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Guidelines for conducting a cost-benefit analysis of Smart Grid projects

Vincenzo Giordano, Ijeoma Onyeji, Gianluca Fulli
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(DG ENER)

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EXECUTIVE SUMMARY

Introduction

Policy goals are largely shaping current transformations in the electricity sector in Europe [EC 2006, 2007a, 2007b, 2011a]. Smart Grids are a key component of the European strategy towards a low-carbon energy future [EC 2011a, 2011b; EEGI 2010; EURELECTRIC 2011]. Significant investments need to be mobilised. According to the International Energy Agency (IEA), Europe requires investments of €1.5 trillion from 2007 to 2030 for the renewal of the electrical system from generation to transmission and distribution [IEA 2008]. A fair allocation of short-term costs and long-term benefits among different players is a precondition for reducing uncertainties and incentivising investments [Clastres 2011; Zio et al. 2011; Jackson 2011].

Given the economic potential of the Smart Grid and the substantial investments required, there is a need for a methodological approach to estimate the costs and benefits of Smart Grids, based as much as possible on actual data from Smart Grid pilot projects.

In this context, in 2011 the Joint Research Centre carried out the first comprehensive collection of Smart Grid projects in Europe to perform a qualitative and quantitative analysis of past and currently running projects and to extract results, trends and lessons learned [EC 2011b].

To complement this work with a quantitative analysis, the present study proposes a comprehensive assessment framework of Smart Grid projects centred on a cost-benefit analysis (CBA). A European Smart Grid project (InovGrid, led by the Portuguese distribution operator EDP Distribuição) has been selected from the Smart Grid project inventory and used as a case study to fine-tune and illustrate the proposed assessment framework. To the best of our knowledge, this is the first study to actually test a CBA methodology on a concrete Smart Grid case study.

Goal of the report

The goal of this report is to provide guidance and advice for conducting cost-benefit analyses of Smart Grid projects. We present a step-by-step assessment framework based on the work performed by the EPRI (Electric Power Research Institute), and we provide guidelines and best practices. Several additions and modifications have been proposed to fit the European context. 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 monetise benefits and costs, and to perform a sensitivity analysis of the most critical variables. It also provides guidance in the identification of externalities and social impacts that can result from the implementation of Smart Grid projects but that cannot be easily monetised and factored into the cost-benefit computation.

The content of our guidelines should be seen as a structured set of suggestions, as a checklist of important elements to consider in the analysis. A comprehensive analysis of Smart Grid projects requires adaptation to local circumstances and will ultimately rely on the professional skills and judgement 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 projects, scenarios and local specificities.

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 Annex 1 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 fulfil the provisions in Annex I 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's '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 CBA.

This study serves as the scientific basis for the CBA section of the EC Recommendations on smart metering deployment [EC 2012a]. It is currently being used as a basis for discussion in the 2012 work programme of the EC Smart Grids Task Force[1] for the definition of eligibility criteria for Smart Grid projects of common interest, according to the provisions in Article 4 of the Regulation Proposal mentioned above.

Proposed assessment framework

In setting up the guidelines for the CBA, our more general target is an economic-oriented CBA of Smart Grid projects, which goes beyond the costs and benefits incurred by the actor(s) carrying out the Smart Grid project. Our guidelines ultimately aim to take a societal perspective in the CBA, considering the project's impact on the entire value chain and on society at large.

The proposed approach also recognises that the impact of Smart Grid projects goes beyond what can be captured in monetary terms. Therefore, our general approach aims to integrate an economic analysis (monetary appraisal of costs and benefits on behalf of society) with a qualitative impact analysis (non-monetary appraisal of non-quantifiable impacts and externalities, e.g. social impacts, contribution to policy goals).

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 tries to include all costs and benefits that spill over from the Smart Grid project 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). To what extent these additional benefits and costs might ultimately be internalised and included in the CBA depends on how defensible the calculation of their euro equivalent is.

The proposed approach to CBA comprises three main parts:

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

To this end, the report aims to provide:

- insights to choose key parameters
- a systematic approach to link deployed assets with benefits
- formulae to monetise benefits
- an indication of most relevant cost categories
- illustration of a sensitivity analysis to identify critical variables affecting the CBA outcome.

As mentioned, the economic appraisal needs to be integrated with a qualitative impact analysis to assess externalities that are not quantifiable in monetary terms. This includes the costs and the benefits derived from broader social impacts like security of supply, consumer participation and improvements to market functioning. To this end, we provide guidelines to identify and assess (in physical terms or through a qualitative description) project impacts and externalities, in order to give decision-makers the whole range of elements for the non-monetary appraisal.

[1] http://ec.europa.eu/energy/gas_electricity/smartgrids/taskforce_en.htm

1. BACKGROUND AND OBJECTIVES OF THE COST-BENEFIT GUIDELINES

Policy goals are largely shaping current transformations in the electricity sector in Europe [EC 2006, 2007a, 2007b, 2011a]. Smart Grids are a key component of the European strategy toward a low-carbon energy future [EC 2011a, 2011b; EEGI 2010; EURELECTRIC 2011]. Significant investments need to be mobilised. According to the International Energy Agency (IEA), Europe requires investments of €1.5 trillion from 2007 to 2030 for the renewal of the electrical system from generation to transmission and distribution [IEA 2008]. A fair allocation of short-term costs and long-term benefits among different players is a precondition for reducing uncertainties and incentivising investments [Clastres 2011; Zio et al. 2011; Jackson 2011].

Given the economic potential of the Smart Grid and the substantial investments required, there is a need for a methodological approach to estimate the costs and benefits of Smart Grids, based as much as possible on data from Smart Grid pilot projects.

In this context, the Joint Research Centre Institute for Energy and Transport carried out a collection of Smart Grid projects in Europe from November 2010 to May 2011 in order to perform a qualitative and quantitative analysis of past and current projects and to extract results, trends and lessons learned. In July 2011, the JRC published the first catalogue of Smart Grid projects in Europe and a comprehensive qualitative analysis of the status and trends of Smart Grid implementation [EC 2011b].

To complement this work with a quantitative analysis, the present study proposes a comprehensive assessment framework of Smart Grid projects centred on a cost-benefit analysis (CBA). We have tested and fine-tuned the proposed approach using preliminary data and results from a Portuguese Smart Grid project, InovGrid.

The assessment framework is structured into a set of guidelines to tailor assumptions to local conditions, to identify and monetise benefits and costs, and to perform a 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 Grid projects but which cannot be easily monetised and factored into the cost-benefit computation.

We emphasise 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 Smart Grid projects requires adaptation to local circumstances and will ultimately rely on the professional skills and judgement of project developers and relevant decision-makers. It is not our goal to provide an exhaustive and detailed set of indicators to fit all possible projects, scenarios and local specificities.

1.1 Policy background

The Directive on internal markets 2009/72/EC [European Union 2009] encourages Member States to deploy Smart Grids and smart metering systems (Article 3). Such deployment may be subject to long-term CBA, as mentioned in Annex 1 of the Directive.

Even though there is already some guidance on a CBA for infrastructure projects at the European level, it is nevertheless important to put forward common criteria to assist Member States in their assessment. The Smart Grids Task Force suggests that these should be based on quantifiable indicators, such as improved energy efficiency and energy savings or lower bills due to better customer feedback etc. [EC Task Force for Smart Grids 2010a, 2010b, 2010c].

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 Member States to fulfil the provisions in 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 CBA.

1.2 Cost-benefit analysis – literature review

The survey on Smart Grid projects across Europe discussed in [JRC 2011] concludes that there are only a few projects that have conducted some form of CBA. While some projects may not have shared their data for confidentiality reasons, many others simply did not have such data because a detailed CBA was beyond the scope of the project, which often predominantly focused on evaluating technologies, applications and solutions. Another reason may be the lack of an established CBA methodology for Smart Grid projects. The literature on this topic is still fragmented.

One of the few systematic approaches developed is the Smart Grid Investment Model (SGIM) by the 2010 Smart Grid Research Consortium[2], which was completed in January 2011 and is only available to Consortium members. The SGIM approach applies only four basic steps to evaluate smart grid investment costs and benefits:

- identify each technology and programme that fits within the scope of smart grids;
- identify benefits of each technology/programme (including cost savings, operational efficiency and reductions in customer kWh, peak kW and hourly load profiles over the next 20 years);
- identify technology, installation programme and management costs based on utility and customer characteristics;
- compare costs and benefits to determine investment returns [SGRC 2011]. One main drawback of this methodology is that it follows more of a utility-centric approach, which is arguably too narrow as it does not take into consideration the benefits for consumers and society at large.

We find that the most advanced work published on the CBA of smart grids so far has been done by the Electrical Power Research Institute (EPRI) in 2010 [EPRI 2010]. Commissioned by the US Department of Energy (DoE), the study leading up to the EPRI methodology was intended to develop a basis for estimating the benefits of individual Smart Grid pilot projects.

The EPRI methodology provides a framework for evaluating economic, environmental, reliability, safety and security benefits from the perspective of all the different stakeholders groups (utilities, customers and society). Its aim is the identification of easy-to-understand, directly measurable and quantifiable benefits. It is the first of its kind to develop a systematic way of defining and estimating the benefits of the Smart Grid. However, this methodology has not yet been tested with a real case study.

Prior to the EPRI study, no structured approach to a CBA for Smart Grid projects had been developed. Instead, there were a number of studies with ideas and concepts that were relevant to the exercise of evaluating costs and benefits of smart grid projects but which had yet to be applied and validated.

A number of studies addressed the development of metrics for evaluating Smart Grid projects. [KEMA 2009] developed a set of metrics to evaluate the impact of Smart Grids in areas such as economic stimulus or energy independence and security. Another study by [Office of Electricity Delivery and Energy Reliability 2008] proposed metrics to measure the progress toward Smart Grid implementation.

Other studies focused on the definition of benefits. While [EPRI 2008] studied the different ways in which utilities estimate societal benefits of smart metering, studies such as [Miller 2008], [NETL 2007] and [Baer et al. 2004] proposed a taxonomy of benefits. The main outcome of these previous studies were benefit categories such as reliability, security and safety, economics, efficiency, environment, etc. and a differentiation between intermediate and final benefits.

[2] Smartgridresearchconsortium.org

Another group of studies put forward different methods, scenarios and assumptions for the estimation of various Smart Grid benefits. [Faruqui et al. 2009] proposed the estimation of side benefits for customers resulting from, for example, dynamic pricing or distributed energy resources. [Kannberg et al. 2003] estimated the national benefits of a Smart Grid deployment, taking into consideration the more efficient use of existing assets. [Anders 2006; L'Abbate et al. 2009; L'Abbate et al. 2011] took a set of benefits, e.g. reduced congestion cost, reduced operational and maintenance costs, higher capacity utilisation, etc., and estimated them for different scenarios.

Though many studies have touched upon the subject of Smart Grid benefits, it is difficult to find studies which have attempted to develop a systematic approach to the definition and evaluation of the costs and benefits of Smart Grid projects and which have tested their approach on real case studies.

One of the reasons for this lack of a formal analysis framework is that evaluating Smart Grid projects based on their investment needs and resulting benefits can prove difficult. The challenge is linked to three main reasons [Jackson 2011]:

- Smart Grid projects are typically characterised by high initial costs and benefit streams that are uncertain and often long term in nature. In fact, many Smart Grid benefits are systemic in nature, i.e. they only come into play once the entire smart electricity system is in place and new market players have successfully assumed their roles.

- Smart Grid assets provide different types of functions to enable Smart Grid benefits. A variety of technologies, software programs and operational practices can all contribute to achieving a single Smart Grid benefit, while some elements can provide benefits for more than one Smart Grid objective in ways that often impact each other.

- The active role of customers is essential for capturing the benefits of many Smart Grid solutions. Especially at this early stage of the Smart Grid development, consumer participation and response are still uncertain and relevant behavioural information (e.g. load profiles) is often not (yet) accessible to utilities.

1.3 Adaptation of the EPRI methodology to the European context

On the basis of the literature review presented in the previous section, the CBA framework described in this study builds upon the EPRI CBA methodology. Modifications (see Annex VIII for details) and additions (qualitative impact analysis, formulae for the quantification of benefits, sensitivity analysis, etc.) tailored to the European context have been proposed wherever necessary. This work draws on the existing collaboration between the Commission and the US DoE in the framework of the EU-US Energy Council.

In April 2011, the EC started a selection process to choose a European Smart Grid project to serve as a case study to test and illustrate a European CBA methodology. The JRC shortlisted three projects from the JRC catalogue [EC 2011b] and held telephone interviews with project coordinators to assess the suitability of each project as a case study for this exercise. EURELECTRIC, the European association of the electricity industry, facilitated and supported this exercise. At the end of the process, the InovGrid project in Portugal was chosen. Throughout this report, we will use preliminary data and information from the InovGrid project to illustrate the steps of the cost-benefit analysis and make them more concrete and understandable.

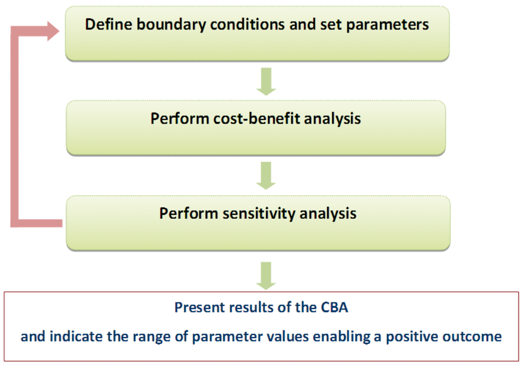
We emphasise that the results of the InovGrid project depend on many project-specific factors related to geography, typology of consumers and regulation. In this study, we have tried to analyse and discuss these factors in order to extrapolate guidelines from this particular case study that can be applied to different typologies of projects with different local circumstances. We therefore invite readers to regard the data and the results provided in this report as an illustration of the methodology and a useful indication of the key aspects which should be considered. The proposed results are not valid under all circumstances. An extrapolation and more general conclusions should be drawn cautiously.

1.4 General approach to the CBA

In setting up the guidelines for the CBA, our more general target is an economic-oriented CBA of Smart Grid projects that goes beyond the costs and the benefits incurred by the actor(s) carrying out the Smart Grid project. Our guidelines ultimately aim to consider the CBA from a societal perspective, considering the project's impact on the entire value chain and on society at large.

The proposed approach also recognises that the impact of Smart Grid projects goes beyond what can be captured in monetary terms. Therefore, our general approach aims to integrate an economic analysis (monetary appraisal of costs and benefits on behalf of society) with a qualitative impact analysis (non-monetary appraisal of non-quantifiable impacts and externalities, e.g. social impacts, contribution to policy goals).

Figure 1: Cost-benefit analysis framework.



Economic analysis – monetary appraisal

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

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

The proposed approach to the CBA comprises three main parts (see Figure 1):

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

To this end, this report aims to provide:

- insights to choose key parameters
- a systematic approach to link deployed assets with benefits
- formulae to monetise benefits
- an indication of most relevant cost categories
- illustration of a sensitivity analysis to identify critical variables affecting the CBA outcome.

The 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 representing the CBA outcome include:

- economic net present value (ENPV) – the difference between the discounted social benefits and costs
- economic internal rate of return (EIRR) – the discount rate that produces a zero value for the ENPV
- B/C ratio, i.e. the ratio between discounted economic benefits and costs.

Qualitative impact analysis – non-monetary appraisal

The overall analysis should also consider externalities that are not quantifiable in monetary terms. This includes the costs and benefits derived from broader social impacts like security of supply, consumer participation and improvements to market functioning.

To this end, it is necessary to identify project impacts and externalities and assess them in physical terms or through a qualitative description, in order to give decision-makers the whole range of elements for the non-monetary 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 Chapter 5 for more details). These weights should reflect the relative importance of the different criteria as determined by the decision-maker; suitable weighting factors to combine the quantitative and qualitative analysis (see Figure 2).

In any case, the appraisal report should argue convincingly, with the support of adequate data, on the weights used to combine all the different elements of the qualitative analysis and to combine the output of the qualitative analysis with the economic analysis.

Based on the assessment framework sketched above, the present report is structured as follows:

Chapters 2, 3 and 4 detail the main components of the proposed CBA framework. More specifically, Chapter 2 provides guidelines for the definition of boundary conditions and the setting of variables and parameters; Chapter 3 provides a step-by-step description of how to identify, monetise and compare costs and benefits of a Smart Grid project; and Chapter 4 illustrates guidelines to conduct the sensitivity analysis of the most critical variables affecting the CBA outcome.

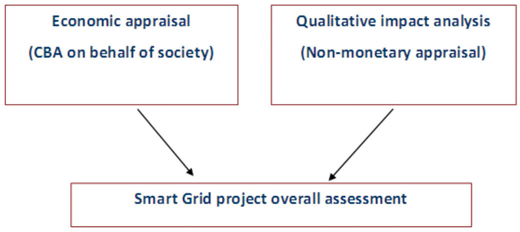


Figure 2: Assessment framework of Smart Grid projects, including economic and qualitative appraisals.

Chapter 5 discusses qualitative impact assessment tools to evaluate additional impacts of the Smart Grid projects (e.g. social impact) that are difficult to capture and to internalise in the CBA.

Finally, Chapter 6 summarises the ten guidelines we recommend for conducting a complete CBA of Smart Grid projects.

2. DEFINE BOUNDARY CONDITIONS AND SET PARAMETERS

The overall project assessment should be tailored to local conditions. Different geographies and contexts will determine different impacts on benefits quantification. This implies clearly spelling out the main variables and assumptions, adapting them to specific project conditions and substantiating their validity. We recommend identifying the data sources used for making assumptions and for selecting parameters and specifying the level of uncertainty (high, moderate, low). We also recommend designing Smart Grid projects that take into account the requirements of the CBA. This is important to ensure that all necessary project data are available to carry out the CBA.

In the remainder of this chapter, we analyse some of these critical variables in more detail. Wherever appropriate, a sensitivity analysis should be considered (see guideline 9).

2.1 Discount rate

The discount rate takes into account the time value of money (the idea that the 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 anticipated future cash flows (which may be less than expected).

The discount rate typically has a significant impact on the assessment of the Smart Grid project. This is because (1) costs are incurred predominantly at the beginning of the scenario, while (2) 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 risks of the projects, then a higher discount rate should be applied to 'smart investments' that have a higher risk level than conventional investments. In this case, however, discounting could lead to seriously undervaluing Smart Grid benefits, particularly systemic benefits that often only come into play 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) may be used. The rationale for choosing a public policy discount rate is to recognise the societal value of Smart Grid investments, the impacts of which go beyond project developers and affect a wide range of stakeholders and society at large. From 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 this case, the project developer (e.g. the system operator) is 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 the project gives to society, regardless of the actual project funding costs. For example, in most countries where utilities' weighted average cost of capital is higher than the societal discount rate, the cost of remuneration of this new investment (rate of return rate over an increased remunerated assets base) and changes in operational cost impacting the regulated tariff may be included as an additional cost of the project in the CBA.

At the European level, societal discount rates of 3.5%, 4% and 5.5% have been suggested [EC 2008, 2009]. However, different values may be proposed and justified, for example on the basis of a specific Member State's macroeconomic conditions and capital constraints. In other cases, the rate of return on utility investments could be a reasonable choice for a discount rate.

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

2.2 Time horizon of the CBA

It is necessary to estimate over how many years the benefits and costs are to be analysed and to clearly explain why the chosen time period is the most appropriate one. The time horizon of the CBA varies according to the nature of the investment. Energy infrastructure projects are generally appraised over a period of 20-30 years [EC 2008].

In the case of investments including assets with a different lifetime, the time horizon may be fixed according to the lifetime of the principal asset, and the renewal of the asset with a shorter lifetime should be included as an additional cost in the CBA. In the case of assets with a very long life, a residual value may be added at the end of the appraisal period (as an investment cost with a minus sign) to reflect their continuing use value [EC 2008].

2 .3 Schedule of implementation

The implementation schedule of the project may have a great impact on the CBA. Different implementation schedules may have different impacts for different stakeholders.

One possible scenario is that net benefits decrease as the implementation rate increases. This may be the case when a particular choice of the discount rate values earlier initial costs much higher than the 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 (e.g. in a smart metering project, when the internal rate of return (IRR) per smart meter is higher than the discount rate), the sooner the installation occurs, the higher the NPV of the installation.

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

The deployment time frame, the expected lifetime and the number of installed assets and the composition of the deployment (urban v rural; concentrated v scattered implementation) are all good candidate variables for a sensitivity analysis (see guideline 9).

2.4 Impact of the regulatory framework on assumptions/parameters

Providing information about the regulatory framework in the Member State where the Smart Grid implementation is taking place (e.g. presence of a risk premium to Smart Grid investments over traditional investment, investment in Smart Grids included in the Remunerated Asset Base) is also recommended, specifying the impact of regulations 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 where the Smart Grid project is taking place, and to show how this may affect the distribution of costs and benefits.

2.5 Macroeconomic factors

Factors such as the inflation rate or carbon costs need to be taken into account in order to make estimates as accurate as possible. In those cases where the calculation of carbon costs is feasible, using the projected EU Emission Trading Scheme carbon prices in the Commission reference scenario up to 2050 as a minimum lower bound is recommended, assuming implementation of existing legislation, but not decarbonisation.[3]

2.6 Implemented technologies

Design parameters, system architecture and technology (as well as the adoption of public standards and protocols) can greatly affect the CBA outcome. Critical variables include the choice and the design of project assets (e.g. automation systems, communication technology, etc.).

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

Also, if relevant, project developers are encouraged to identify alternative project options that will be evaluated against the baseline scenario (business as usual). These options should reflect different project investments in terms of scope, size, engineering features, etc.

Cost reduction associated with technology maturity needs to be taken into account as well, in order to make estimates as accurate as possible. The latter is important as international penetration of Smart Grid technologies results in price reductions in real terms. Finally, in some instances it may be necessary to use forecasts on the penetration of new assets and applications, like distributed generation and demand response, as they may have an impact on the implementation choices made today.

2.7 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 et al. 2010]. Therefore, 'shaving off' peak demand would postpone, reduce or even eliminate the need to install expensive and possibly polluting peak generation capacity. Depending on the incentives a project provides for shifting peak load to off-peak hours (e.g. demand response through various forms of dynamic pricing), projects can achieve up to 30% peak load transfer [Faruqui et al. 2010].

2.8 Electricity demand

The 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 the electricity demand or the demand growth on country-specific forecasts.

Electricity price developments should also be taken into account. Since electricity savings are typically one of the most significant benefits resulting from the implementation of smart meters (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 prices obviously have a large impact on the outcome of the CBA and should therefore be subject to a sensitivity analysis (see guideline 9).

3. COST-BENEFIT ANALYSIS

The core of our assessment framework is expressed by the definition of a CBA methodology for Smart Grid projects. The following seven steps are the elements of our proposed CBA framework (Figure 3), based on the approach developed by EPRI [EPRI 2010]. The outcome of the CBA is then refined through a sensitivity analysis, which aims to identify the range of critical variables for which the CBA outcome is positive.

The main idea behind the EPRI methodology is that assets provide a set of functions[4] that can in turn enable Smart Grid benefits which can be quantified and eventually monetised. In our modified version of the methodology, we propose mapping (1) assets on to functionalities, (2) functionalities on to benefits, and (3) benefits on to 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: (1) they assist in thinking of sources of benefits, making a complete set of estimated benefits more likely, and (2) they make possible the evaluation of the impact of a project, i.e. measuring progress toward attaining characteristics of the Smart Grid through specific key performance indicators (KPIs) that were proposed by [EC Task Force for Smart Grids 2010a] and will be used in the qualitative impact analysis detailed in Chapter 5.

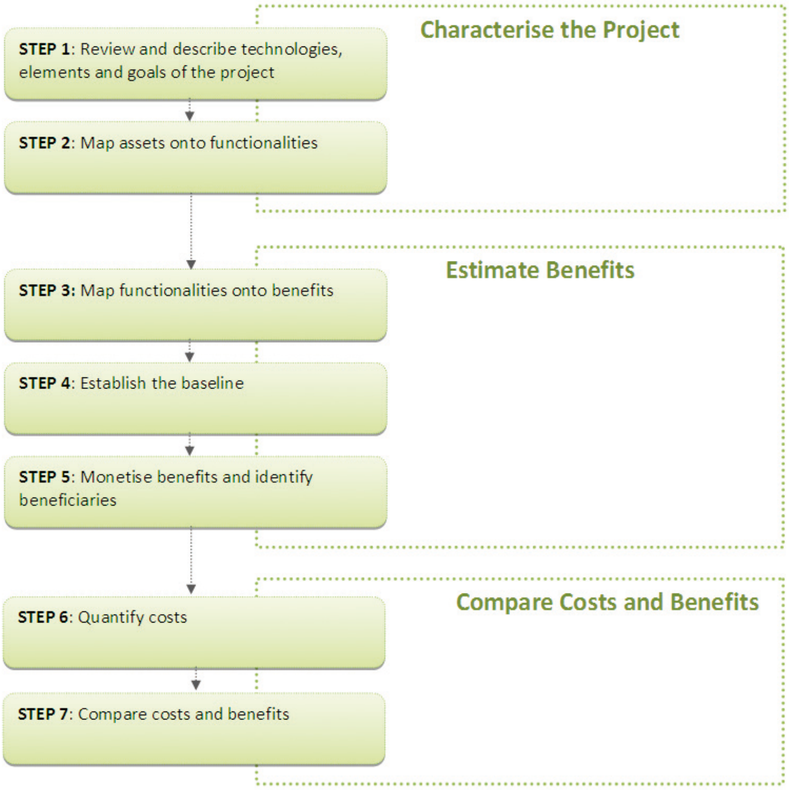


Figure 3: Cost-benefit analysis framework.

The links between assets and benefits through functionalities is not straightforward and requires a good deal of thinking. Nevertheless, after testing this step on real case studies we think it is useful to perform these steps, as the identification of functionalities helps project coordinators to place their project in the Smart Grid context, clarify concepts and recognise how they have achieved the benefits.

[4] For a discussion of functions v functionalities, refer to Annex VIII.

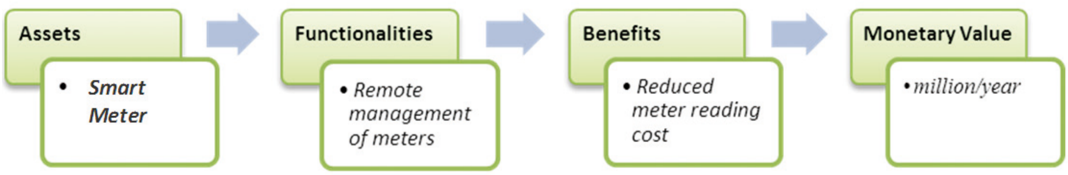


Figure 4: Mappings applied in the analysis.

As for the scope of the analysis, it should consider the whole value chain and society at large. This is important in order to discuss Smart Grid project impacts in terms of the overall Smart Grid social surplus and, accordingly, share costs and benefits fairly among different stakeholders.

This requires:

- identifying all the actors affected directly and indirectly by the Smart Grid project. This implies considering all the actors directly involved in the project (e.g. distribution system operators (DSOs) and consumers), all other actors in the electricity system who are affected by the project (e.g. retailers, generation companies, aggregators, etc.) and society at large;
- quantifying (to the greatest possible extent) the costs and benefits of all actors after the project. This requires including all quantifiable externalities (i.e. quantifiable costs and benefits that spill over from the project into society). As mentioned before, non-quantifiable externalities (e.g. social impact, consumer inclusion, etc.) will be dealt with qualitatively (see Section 3.5);
- adding up all the costs and benefits of the different actors. Total costs/benefits are the sum of the costs/benefits to all players (including society). Transfer payments among different players cancel each other out and should not contribute to the overall cost-benefit calculation.

CBA Step 1 – Review and describe the technologies, elements and goals of the project

The first step is to provide a main summary and to describe the elements and goals of the project.

The project must be clearly defined as a self-sufficient unit of analysis. This may involve providing (some of) the following information:

- the scale and dimension of the project (e.g. in terms of consumers served, energy consumption per year)
- the engineering features (e.g. the technologies adopted and the functionalities of the 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
- the regulatory context and its impact on the project.

Illustration of Step 1 with InovGrid

The InovGrid project[5] aims to replace the current Low Voltage (LV) meters with electronic devices called EDP Boxes (EBs), using AMM (Automated Meter Management) standards. The EB is a gateway to energy management and includes the functions of smart metering. It can interact locally with other devices through a Home Area Network (HAN) interface.

Local control equipment (DTC or Distribution Transformer Controller) in secondary substations performs automation functions for the distribution transformer, collects information from the EBs and sends it to the upstream systems.

The main demonstration site of the project is the municipality of Évora in Portugal, which has a population of 54 780 and covers an area of 1 307 km^2. There are around 32 000 electricity customers, whose annual consumption equals approximately 273 GWh.

The main components of the system are:

- **EDP Boxes (EBs)**: devices to be installed at consumers/producers (including modules for metering, control, processing, interface, communication, etc.);
- **Distribution Transformer Controller (DTC)**: local control equipment to be installed in MV/LV (middle voltage/low voltage) transformers (including modules for measuring, actuation, processing, interface, communication, etc.);
- **Grids/Communications**: equipment and technologies for information transmission;
- **Information Systems**: systems and applications for management and central data processing.

[5] http://www.inovcity.pt/en/Pages/homepage.aspx

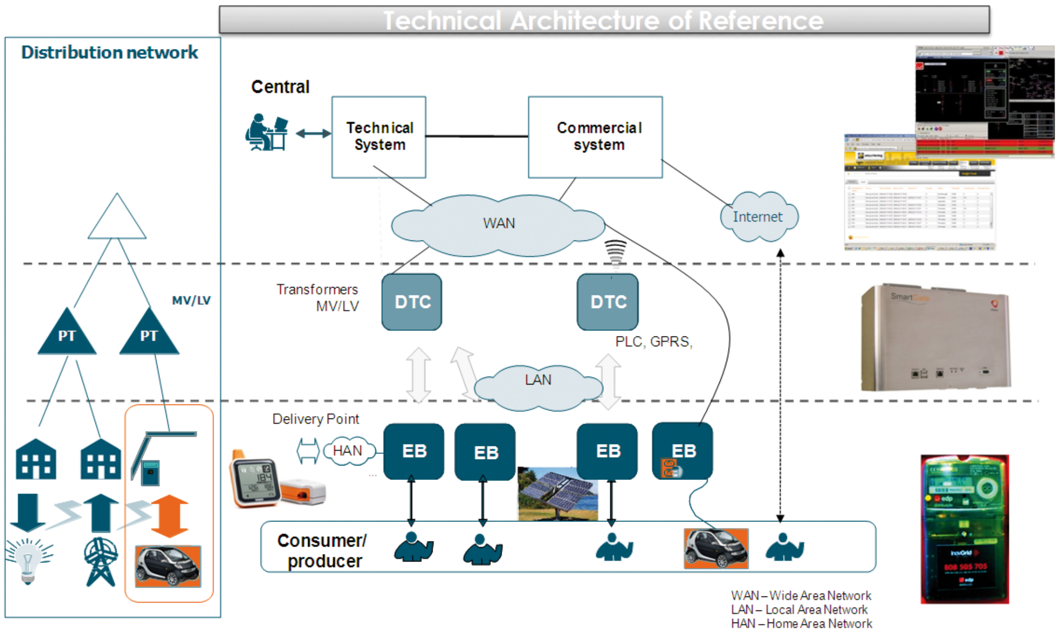


Figure 5: InovGrid project – technical architecture.

Figure 5 outlines the overall reference architecture of the InovGrid platform, highlighting the major players, their roles and the communication infrastructure.

CBA Step 2 – Map assets on to functionalities

Determining which Smart Grid functionalities are activated by the assets proposed by the project is an important early step in a CBA for Smart Grid projects. Smart Grid assets provide different types of functionalities that enable Smart Grid benefits. If the assets deployed and/or functionalities enabled by the project are unclear, the analysis is likely to be incomplete.

To complete this step, consider the assets of the project. 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. The functionalities are listed in Annex III.

Illustration of Step 2 with InovGrid

Table 1 provides a list of assets that are taken into account when assessing costs and benefits of the InovGrid project.

Table 1: List of assets deployed in the InovGrid project.

Infrastructure	**EDP Box (EB)**	Device that includes a measurement module, control module and communication module and which is installed at the consumer/producer site.
	HAN Module	Communication and control module that allows reading of the records of the local EB (e.g. consumption, power consumption profile, historical events, quality of service) by connecting to other devices.
	Distribution Transformer Controller (DTC)	Local control equipment will be installed in distribution transformer stations, the main components being a measurement module, a control module and a communication module. Its main functions are: collecting data from the EB and MV/LV substation, data analysis functions and grid monitoring.
	DTC Cell Module (Distribution Automation)	Module that enables the turning on and off remotely or locally of the various independent circuits of the MV/LV substation. This is a critical component for Distribution Automation for providing new functionalities like remote management and automatic network reconfiguration.
	DTC Power Quality Module	Module that allows the recording and reporting of the quality characteristic values of the wave voltage (root mean square value, flicker, voltage dips, harmonics), providing information and generating alarm events.
Information Systems	**InovGrid Infrastructure Management**	Includes all features related to the execution of commands and data collections of the InovGrid infrastructure, with the possibility of being integrated into commercial systems, management of communication and InovGrid network settings.
	Meter Data Management (MDM)	Repository of data collected from InovGrid infrastructure, including consumption, readings, events, status and data network quality. It also includes the main functions of the data validation received, management of InovGrid equipment (DTCs and EBs).
	Energy Data Management (EDM)	Includes the features related to the treatment of consumption figures collected, including the estimation of missing or invalid data, aggregation data functions and publication of data. Also includes features related to the profiling of added value based on the rules and profile type in force.
	DSO Web Portal	DSO web page that offers access to remote commercial services and to data consumption/production, with the possibility of using functions of data analysis.
	Supervision Module	Comprises components directly related to the supervision of InovGrid solutions, including the treatment of events/incidents, the overall performance management solution (InovGrid equipment and systems) and the management of the service provided by the solution.
	Meter Asset Management (MAM)	Repository for registration of features and configurations of the equipment-based infrastructure InovGrid (DTC and EB), including the management of their history..
	Distribution Management System (DMS)	Comprises a monitoring and control system, remote data collection devices and sensors. It enables real-time communication with the infrastructure, with the possibility of remote control actions on the network.
	DPlan	A simulation and analysis system that optimises investment and operations planning.

FUNCTIONALITIES

ASSETS	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	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
EDP Box	•	•	•	•	•	•	•			•	•	•	•			•	•		•	•		•	•		•	•	•	•	•	•	•		•
HAN Module																						•			•			•		•	•		•
Distribution Transformer Controller (DTC)	•	•	•	•	•	•	•		•	•	•	•	•		•	•	•		•	•	•	•	•					•	•				
DTC Cell Module			•		•																												
DTC Power Quality Module		•	•			•	•	•		•									•														
InovGrid Infrastructure Management	•	•	•	•			•	•	•	•	•	•	•	•	•	•		•	•	•		•	•	•	•	•	•	•	•	•			•
Meter Data Management (MDM)		•		•	•	•	•	•	•	•	•	•	•		•	•	•	•	•		•			•				•	•	•			•
Energy Data Management (EDM)							•		•											•	•			•									
DSO Web Portal	•	•																		•	•	•	•	•	•			•	•	•	•	•	•
Supervision Module		•	•	•	•	•	•	•		•					•			•	•														
Meter Asset Management (MAM)								•										•											•				
Distribution Management System (DMS)		•	•	•	•	•	•	•		•	•	•		•	•				•														

Figure 6: Map each asset on to the functionalities it provides.

The assets identified (see Table 1) are deployed in a project to improve the power grid through a number of enhancements.

Figure 6 illustrates the mapping of assets on to functionalities for the InovGrid project. The dots in the cells represent the functionalities provided by the project and show which assets activate them. The assets-functionalities matrix is given in Annex V.

CBA Step 3 – Map functionalities on to benefits

The purpose of this second mapping is to link the functionalities identified in Step 2 to the (potential) benefits they provide. For this purpose, we use the 22 Smart Grid Benefits put forward by the EPRI methodology[6] (see Annex I). These benefits are divided into ten sub-categories, which are grouped into four main benefit categories: *economic, reliability, environmental* and *security*.

The project coordinator should consider each functionality individually and contemplate how it could contribute to any of the benefits listed in the first column. This analysis should continue until all applicable functionalities have been considered. The functionalities-benefits matrix is given in Annex VI.

Illustration of Step 3 with InovGrid

Figure 7 summarises this assessment for the InovGrid project. The dots in the cells mark the benefits of the InovGrid project identified through the mapping exercise. The green columns represent the functionalities provided by the project's assets, as identified in Step 2.

It is worth noting that it is quite likely that some of the functionalities identified in Step 2 are not necessarily going to be mapped onto any of the benefits in Step 3. The InovGrid case study shows that even though the group of assets employed in the project (is expected to) activate every functionality (as demonstrated in Step 2), four of them do not appear to be linked to any of the benefits in Step 3 (see Figure 7). There can be several reasons for this as the outcome of this mapping depends strongly on various factors, such as (but not restricted to):

- nature, size and scope of the project;
- measurability or applicability of certain benefits depending on the types of organisations involved (e.g. a DSO might not be able to calculate *deferred transmission capacity investments*);
- monetisation of benefits (e.g. project assets may activate functionality 26: *Provide grid users with individual advance notice of planned interruptions*. This could lead to a significant increase in customer satisfaction, which is an important benefit with the increase of competition in the power market but is very difficult to monetise);
- regulations (e.g. functionality 11: *Allow grid users and aggregators to participate in ancillary services market* may be more relevant to projects in countries where the regulations allow such participation).

[6] Note that these benefits differ from the ones put forward by the Smart Grids Task Force [EC Task Force EG3 2010]. They represent concrete final benefits that can be monetised.

FUNCTIONALITIES

BENEFITS	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	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
Optimised 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 in Contracted Power							•																										
Reduced Electriciy Cost								•				•										•			•			•	•				
Reduced Sustained Outages			•	•	•			•					•				•			•													
Reduced Major Outages					•									•																			
Reduced Restoration Cost					•	•	•																						•				
Reduced Momentary Outages					•	•	•																						•				
Reduced Sags and Swells						•	•																										
Reduced CO_2 Emissions	•	•				•	•	•	•	•		•					•		•			•	•		•			•	•	•	•	•	
Reduced SOx, NOx, and PM-10 Emissions	•	•				•	•	•	•	•		•					•		•			•	•		•			•	•	•	•	•	
Reduced Oil Usage	•	•				•	•																•					•	•				
Reduced Wide-scale Blackouts																																	

Figure 7: Map each functionality on to a standardised set of benefit types.

CBA Step 4 – Establish the baseline

The objective of establishing the project baseline is to formally define the 'control state' that reflects the system condition which would have occurred had the project not taken place. This is the baseline situation against 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 project.

EPRI describes the two types of states of the system necessary to evaluate the difference between the BaU and the 'with project' scenario as:

- Scenario A: The baseline conditions that reflect what the system condition would have been *without* the Smart Grid system;
- Scenario B: The realised and measured conditions *with* the Smart Grid system installed (see Table 2 to find examples of scenarios A and B for Smart Grid benefits).

In order to quantify any particular benefit, it is necessary to define scenarios A and B and measure the difference in that benefit metric between scenarios A and B.

It is worth noting that in a CBA, it is most appropriate to use incremental, or marginal, costs and benefits associated with Smart Grid investments. This is important when developing baselines, as they comprise the incremental component of both costs and benefits.

Control Groups In Smart Grid projects 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' behaviour, and in turn on customers' peak load curves and electricity bills. Baselines in such situations are preferably a 'control group' of comparable customers randomly selected from the target population [EPRI 2010].

Even though historical consumption data is always a good indication of the BaU scenario, certain factors are likely to vary over time, and it is therefore important to work with control groups. This method helps project evaluators to more accurately compare project scenarios with a baseline scenario.

When establishing the target group(s) of customers, i.e. the group(s) that will reflect the impacts of the project, 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 who volunteer to participate in the pilot. It is also advisable to conduct a statistical analysis on the customers who refuse to participate in the project in order to better understand this segment of consumers.
- **Exclusive focus on 'premium' groups** Do not measure benefits only in groups with very good access to information and a high

propensity to adopt new technologies as this will significantly bias the results. Define the segmentation of customers such that it covers all types of consumers, independent of social status and education.

- **Ability to extrapolate results to a national level** When working with sample groups, there is always the risk of not being able to identify the drivers that allow the extrapolation of the local results to a country level, so 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 on a national level.

- **Mismatch between segments and products & services** The risk of products and services offered not being compatible with certain customer segments can be mitigated by conducting an initial socio-demographic analysis to identify which products and services are most likely to work best in which segments.

Illustration of Step 4 with InovGrid

Baselines

For the development of project baselines, InovGrid uses historical data, such as the estimated growth rate of the client base or the cost reduction associated with technology maturity/year, adjusted by forecasts for baseline metrics, such as the projection of demand growth, inflation and evolution of electricity prices (€/MWh). *Historical data* can be used for (relatively) stable conditions over the project period, while *forecasted data* is typically used for baseline metrics that are expected to vary over short time periods, such as electricity demand growth or electricity prices [EPRI 2010]. Table 2 provides some examples from InovGrid of scenarios A and B with the types of metrics that were used to estimate benefits. It shows an excerpt of values assigned to baseline metrics. InovGrid measured costs and benefits at incremental levels.

Table 2: Examples from InovGrid of baseline conditions for Smart Grid benefits.

BENEFIT	A: BASELINE CONDITION (BaU)	METRICS USED*	B: ESTIMATED/REALISED CONDITION (InovGrid)	METRICS USED*
Reduced Meter Reading Cost	Cost with local meter readings	• Meter reading cost/ client/year (H) • Number of LV clients (H) • Inflation rate (F)	Reduced cost of obtaining local 'disperse' readings (i.e. readings from clients without smart meters or experiencing communication failures): with InovGrid infrastructure, only clients who are unable to use the EDP Box and those who experience communications failure will require local meter-reading services	• Communications success rate (H) • % of customers unable to use EDP Box (F) • Cost of 'disperse' local readings
Reduced Outages[7]	Losses relating to power outages (BaU)	• Annual revenue LV • Number of minutes/ year (H) • Estimated number of minutes non- supplied/ year BaU (H) • Economy cost per kWh of load not served (F)	Reduced losses relating to reduced outage: InovGrid infrastructure is expected to reduce outage times (time between a breakdown and the restoring of supply) due to monitoring and real-time network information and quicker detection of anomalies	• Reduced outage through DTC and EDP Box (F) • Reduced outage through DA-DTC Cell (F)
Reduced Distribution Maintenance Cost	Maintenance cost of transformers and secondary substations (BaU)	• Direct costs relating to maintenance of transformers and secondary substations (H)	Reduced maintenance cost: InovGrid infrastructure makes it possible to remotely control and monitor asset condition and utilisation and avoid site visits	• Reduced maintenance cost: InovGrid infrastructure makes it possible to remotely control and monitor asset condition and utilisation and avoid site visits
Reduced CO_2 Emission	CO_2 Emissions (BaU)	• Operational fleet (number of vehicles) (H) • Number of km driven in 2010 (H) • Consumption of diesel (litres/km) (H) • Value of a metric ton of CO_2 (F)	Reduction in CO_2 emissions: InovGrid infrastructure enables reduction of total mileage through the reduction of local meter readings and operations, and therefore a reduction in CO_2 emissions.	• Estimated % reduction in total mileage (F)

[7] It is worth clarifying that in the InovGrid project two different capabilities lead to the reduced outage benefit in Table 2: the implementation of the smart metering system and of the distribution automation system. Specifically, it is expected that the smart metering infrastructure will reduce outage times in LV and MV networks (in terms of SAIDI, SAIFI and TIEPI) by 5% due to (1) monitoring and real-time network information, and (2) quicker detection of anomalies and reduced amount of time between a breakdown and the restoring of the supply. Additionally, investment in DTC Cell will allow remote management and automatic network reconfiguration in selected networks. Internal studies and experience at EDPD show that an additional investment of DTC Cell in selected (problematic) networks would significantly reduce TIEPI.

* (F) refers to forecasted metrics; (H) refers to historical metrics.

Control groups

Control groups could consist of consumers chosen from both within the pilot area and outside. They should have no knowledge of the project. InovGrid, for example, is testing different new products and services, such as new tariffs (through simulation, such as for example the 'Time of Use' (ToU) tariff, consumption levels tariff, target kWh tariff), pre-payment plans and alerts (e.g. hourly load diagrams), on different client segments in order to evaluate changes in energy efficiency. In this case, the baseline was established with historical consumption data and control groups – both inside Évora and in a nearby city – which are completely unaware of the project. For certain indicators, it might be more suitable to use the rest of the country as a control group (to ensure data quality and consistency of estimations). This will ensure that results are more easily extrapolated to a national level. Examples of such indicators from the InovGrid project include temperature, electricity demand or GDP impact.

In total, 1 250 customers were selected for testing special services. A random stratified sampling method was used to identify groups in order to ensure statistical validity. The various effects on energy efficiency are being analysed, taking into consideration the different products and services (SMS alert, in-home displays (IHD), smartphone applications, etc.) made available to the different customer segments (see Figure 8).

The idea is to test, cumulatively, different products and services on different groups:

- control group (outside Évora) has no information;
- control group in Évora is testing the 'InovCity Effect', which is the impact on energy efficiency caused by (1) invoicing based on remote real readings with no estimations, (2) remote operations, (3) client access to more and new information as load diagrams, and (4) generic measures of promotion of the project in Évora city (e.g. conferences, involvement with local stakeholders, etc.);
- test Groups – there are six different segments within the test group. Some segments will test alerts/messages, some others will test simulated tariffs and others will test in-home displays and access to real-time information.

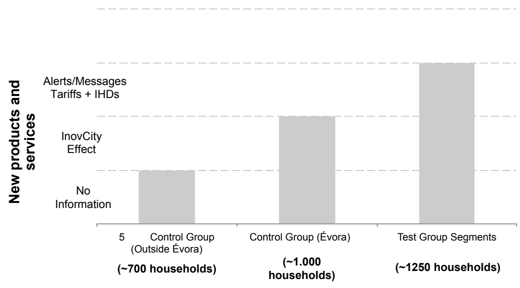


Figure 8: Example of set of control groups to test the impacts of different services and products.

CBA Step 5 – Monetise the benefits and identify the beneficiaries

Once the baseline and project scenarios have been defined, projects need to identify, collect and report the data required for the quantification and monetisation of the benefits. This data might be raw data, such as hourly load data, or data that is already analysed, such as line losses. Annex I presents the list of benefits proposed in [EPRI 2010].

Identify and compile the data

This sub-step involves identifying and compiling the necessary data from the project. The benefits to be calculated (identified in Step 3) and the baseline scenarios needed to calculate those benefits (identified in Step 4) determine the type of data needed. For each benefit identified in Step 3 and each baseline condition identified in Step 4, this step identifies and compiles the data required for calculation. Data should be collected both before and after implementation of the Smart Grid project. As mentioned earlier, we recommend taking into consideration the data requirements of the CBA in the design phase of the project. Table 2 provides examples of metrics used for the calculation of baseline and project conditions.

Quantify the benefits

As mentioned earlier, the benefits of a project represent the change between baseline and project conditions. Depending on the project, changes can occur at the level of distribution costs, greenhouse gas emissions or power quality. In general, the monetary value of a benefit can be calculated as:

$$\textit{Value } (€) = [\textit{Condition}]_{\textit{Baseline}} - [\textit{Condition}]_{\textit{Project}}$$

For example, the estimation of the benefit reduction in meter reading costs could be done by comparing the total cost of local meter readings for a control group which does not have smart meters installed (i.e. BaU scenario) to the cost of local meter readings under project conditions for a fraction of customers who are unable to use the smart meter or experience communication failure and therefore need local meter-reading services (i.e. Smart Grid project scenario). Alternatively, the project could always directly report the reduced costs, i.e. benefits, for example by using percentage variations of variables impacting the baseline scenario. Table 2 provides examples of baseline v project conditions from the InovGrid project.

Monetise the benefits

This step entails monetising (i.e. expressing in equivalent economic terms) the benefits quantified in the previous sub-step. Compilation and comparison of benefits which are very different in nature (e.g. reduction of technical losses, reduced outages, reduced CO_2 emissions) requires expressing them in a common unit of measurement.

Annex II offers an approach for quantifying and monetising some Smart Grid benefits. For a more detailed characterisation of benefits, we have suggested formulae for the monetisation and included the rationale behind the benefit calculation.

Identify the beneficiaries

As recommended in [ERGEG 2010], when conducting a CBA it is important to consider an extensive value chain and allocate benefits to different beneficiaries, like consumers, DSOs, retailers/aggregators and society at large [EPRI 2010; ERGEG 2010]. The results of CBAs are likely to vary across different stakeholder groups. In undertaking the CBA, the advice is not to restrict the perspective to costs and benefits incurred by the player responsible for the Smart Grid implementation (e.g. DSOs).

Whenever feasible, it is also worth performing a CBA for each of the actors involved. This may provide a useful indication of how costs and benefits are distributed across the whole value chain. Data required to perform this kind of analysis is typically a sub-set of the data required for the overall CBA.

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.

Assess uncertainty

When undertaking Step 5, it may be useful to characterise the relative level of precision of quantified/monetised benefits. It may not be possible to estimate some Smart Grid benefits, like those based on environmental or social factors, with the same level of confidence as other benefits. Therefore, the EPRI methodology suggests providing at least some basic information regarding uncertainty in cost estimates and project outcomes with the goal of making available useful information on the certainty level of estimates to potential users of the CBA results.

The information on the certainty level is based on judgemental evaluations by the research team undertaking the CBA. The recommendation is to try to identify the individuals most acquainted with the problems at hand in order to obtain results that are as precise as possible. EPRI [EPRI 2010] suggests using four broad categories to characterise a general level of precision for costs/benefits, as presented in Table 3.

Table 3: Four categories of uncertainty levels (source: EPRI methodology [EPRI 2010]).

Level of certainty	Explanation
MODEST level of uncertainty	Most estimates are expected to be subject to uncertainty. A modest level of uncertainty in quantitative estimates and/or in monetisation implies a level of confidence and precision where the estimate is viewed to be ± 20% with at least an 80% level of confidence, i.e. there is an 80% probability that the actual value is within ± 20% of the estimate.
SIGNIFICANT level of uncertainty	Some estimates may be subject to greater levels of uncertainty. The category ‘significant level of uncertainty’ would be for estimates where the estimate is viewed to be ± 40% with at least an 80% level of confidence, i.e. there is an 80% probability that the actual value is within ± 40% of the estimate in quantitative metrics and/or in how to monetise.
HIGH level of uncertainty	This would be for estimates that are very uncertain and difficult to quantify. The implicit precision level is viewed as ± 100% with a 95% level of confidence.
Uncertainty range cannot be quantified	This should be limited to benefits that fall into the speculative category and are so uncertain that they can only be expressed as an order of magnitude estimate.

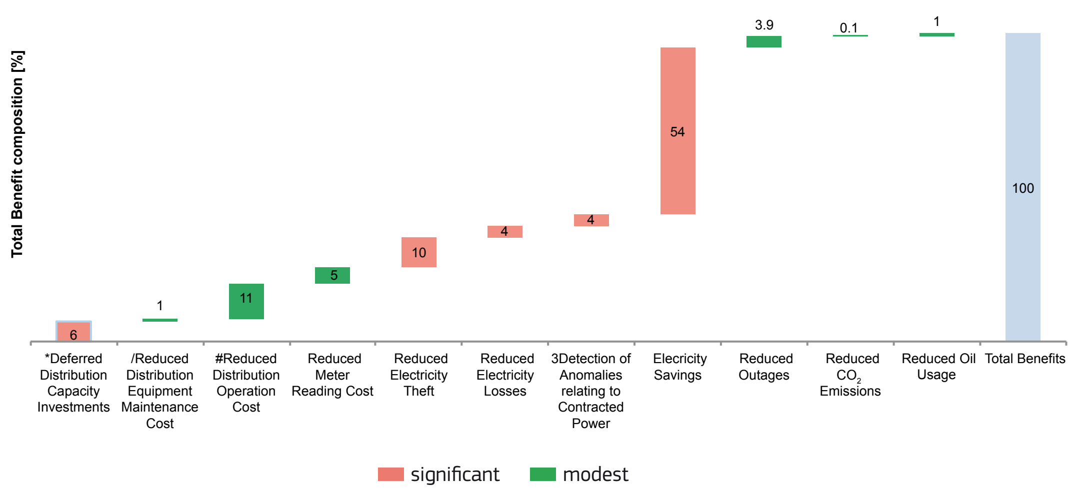


Figure 9: Example of possible benefits breakdown (%) with indication of uncertainty levels;

For the sake of illustration, Figure 9 shows a possible breakdown of total benefits (in percentages), highlighting certainty levels by colour.

CBA Step 6 – Identify and quantify the costs

The costs of a project are those costs incurred in implementing the project, relative to the baseline. Generally, it is more straightforward to quantify the costs of a project than the resulting benefits. Some costs can be measured directly by the investing companies, while others are typically easy to estimate since their prices, or very good proxies, can be obtained in the marketplace.

Step 6 is important in order to evaluate the cost-effectiveness of the Smart Grid project. Collecting information on the project's costs allows the calculation of a project's return on investment, which shows whether it is positive, and if so, when the project will break even. Even though identifying these costs is not usually a difficult exercise, it does require meticulous itemisation of all important costs.

In general, (1) cost data is a combination of estimated costs obtained through dialogue with suppliers and of data coming directly from the project and tracked by the company; (2) according to EPRI "capital costs are amortized over time; each project is to estimate its activity-based costs, using its approved accounting procedures for handling capital costs, debit, depreciation, and taxes" [EPRI 2010]; (3) costs should *only* be those necessary and sufficient for the purpose of implementing the Smart Grid measure(s).

Taxes (energy taxes, VAT) should not be incorporated into the CBA [EC 2008].

Illustration of Step 6 with InovGrid

EDP Distribuição estimated the relevant costs of the InovGrid project through a market consultation at the beginning of 2011. The results provided reasonable estimates of costs of action for a Smart Grid project, such as the costs of smart meters, a telecommunication network, etc. Each of these elements has an investment cost that can be determined through dialogue with the industry. As an example, Table 4 (see next page) gives a list of costs of actions identified for the InovGrid project.

CBA Step 7 – Compare costs and benefits

Once costs and benefits have been estimated, there are several ways to compare them in order to evaluate the cost-effectiveness of the project. The most common methods, as suggested by the EPRI methodology, are summarised below.

Annual comparison This method consists in compiling costs and benefits annually over the study period in order to make annual comparisons (Figures 10 and 11). This approach is

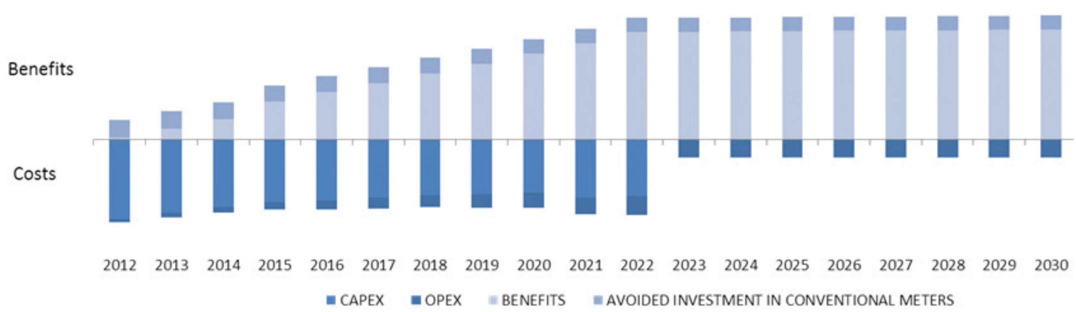


Figure 10: Example of annual comparison.

Table 4: Some costs tracked for the InovGrid project.

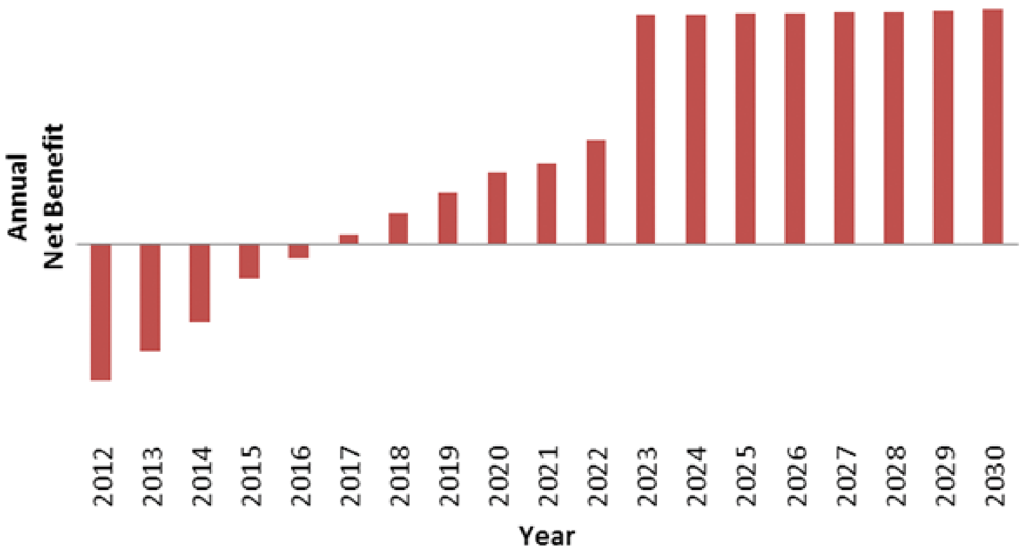
General Category	Type of cost to be tracked for roll-out and to be estimated for the baseline
CAPEX	Investment EDP Boxes (including home area network)
	Investment in Distribution Transformer Controllers
	Investment IT
	Investment communications
	Sunk costs of previously installed (traditional) meters
OPEX	IT maintenance cost
	Network management and front-end cost
	Cost of GPRS communications
	Communication/data transfer costs
	Scenario management costs
	Replacement/failure smart metering systems (incremental)
	Revenue reductions (e.g. through more efficient consumption)
	Meter reading
	Call centre/customer care
	Training cost (e.g. customer care personnel and installation personnel)
	Cost of consumer engagement programmes

useful in identifying individual years in which costs surpass benefits or the other way round.

Cumulative comparison: This method presents costs and benefits cumulatively over time, i.e. the cost of each year is the sum of that year's value in addition to the value of all previous years (Figure 12). This approach is useful in identifying the point in time when benefits exceed costs (i.e. the 'break-even' point).

Net present value (NPV): This method consists of estimating the sum of net present values of individual cash flows of the Smart Grid project for the entire study period. The project needs to (1) subtract estimated costs from benefits for each year, (2) discount these annual net benefit amounts, and (3) sum up the discounted values. The net NPV can be understood as the net benefit 'brought back' to the baseline year by applying a discount rate, thereby accounting for the time value of money.

Figure 11: Example of annual net benefit.



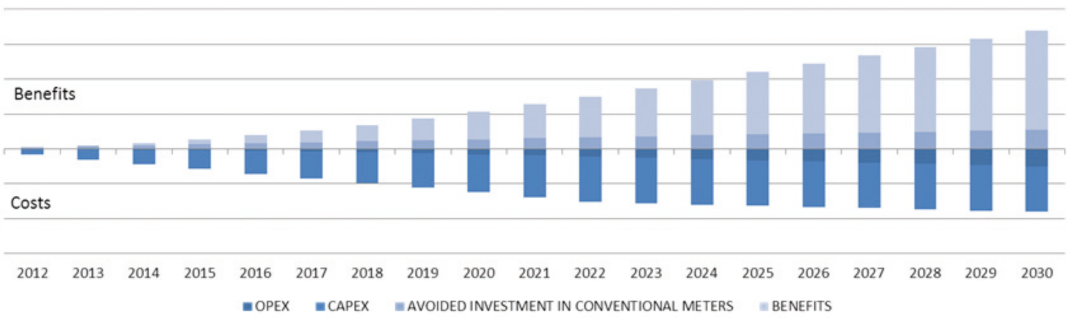


Figure 12: Example of cumulative comparison.

The NPV is calculated as follows:

$$\sum_{t=0}^{n} \frac{R_t}{(1+i)^t}$$

where

t is the time of the cash flow;

i is the discount rate;

R_t is the net cash flow (cash inflow minus cash outflow at time *t*).

n is the total number of periods (typically years) considered

A small discount rate sets future values close to present ones, while a larger discount rate incrementally devalues present values of future cash flows, usually indicating the presence of an alternative option of investment in financial markets [UNEP 2009].

For the sake of illustration, Figure 13 gives a hypothetical example of a comparison of discounted costs and benefits, and the estimated net benefit (NPV).

Benefit-cost ratio: A project's value can also be represented as a ratio of benefits to costs (either on a present value basis or on an annual basis). This method is a simple way of representing the size of the benefits relative to that of the costs. If the ratio is greater than one, the project is cost-effective.

Use of a computational tool

The US Department of Energy (DoE) has designed a computational tool to streamline the implementation of the EPRI methodology to DoE-funded projects. The tool guides project coordinators in the input of data and the calculation of project performance metrics [US DoE 2011].

Drawing on the DoE computational tool in the framework of the on-going collaboration with the US DoE, the JRC is presently exploring the possibility of creating a similar computational tool with all the methodological steps presented in this report.

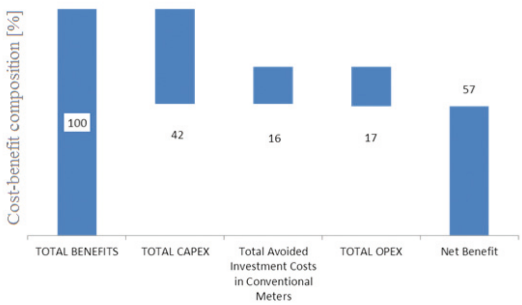


Figure 13: Example of NPV composition (total benefit 100%).

4. SENSITIVITY ANALYSIS

In this section, we discuss guidelines and best practices for the implementation of a sensitivity analysis to the main assumptions and variables of the CBA. A sensitivity analysis is a necessary component of a CBA. The reason is two-fold.

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. The legacy characteristics of a country's power grid and primary drivers for implementation of a Smart Grid may vary significantly from one country to another and will determine the relative importance of one project over another, according to the potential benefits provided. For example, different consumption trends and/or varying installed capacity across countries can strongly influence the variable *Deferred Distribution Capacity Investments*. Also, the benefit of *Reduced Technical Losses* may amount to a lower value in countries where consumption is either more concentrated or closer to the generation points. Other values that are likely to vary significantly across countries include *Reduced Electricity Cost*, *Reduced Outage Cost* and *Reduced Electricity Theft*, as they all strongly depend on country-specific variables.

Secondly, a CBA is 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 forecasts that are considered to be the most probable. However, these forecasts often cover a long period of time and may thus differ significantly from values actually realised. 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 project, i.e. to perform a sensitivity analysis.

A sensitivity analysis indicates to what extent the profitability of a project is affected by variations in key quantifiable variables. This analysis is most commonly performed by calculating changes in a project's internal rate of return (IRR) or NPV.

The goal of the sensitivity analysis is to find the range of variables leading to a positive outcome of a CBA. This requires identifying the switching value of critical variables, i.e. the value that would have to occur in order for the NPV of the project to become zero, or more generally, for the outcome of the project to fall below the minimum level of acceptability.

The use of switching values in the sensitivity analysis allows appraisers to make some judgements on the riskiness of the project and the opportunity of undertaking risk-preventing actions. For example, if one of the critical variables of a Smart Grid project is 'energy savings' and its switching value is 0.5%, then the project promoter can evaluate if the conditions for such a consumption decrease exist and, in a positive case, may consider strengthening preventing actions (e.g. larger information campaign, in-home visualisation tools, etc.).

In the following sections, we list some of the critical variables affecting the results of a Smart Grid CBA. For these variables (as a minimum), a sensitivity analysis should be undertaken.

4.1 Estimated growth rate of energy consumed and energy efficiency potential

The estimated growth rate of energy consumed significantly affects the benefit calculation and varies considerably from country to country and according to different sources. The most recent estimate by the DoE/EIA predicts that the European nations of the OECD will experience an annual increase in electricity generation of 1.2% [EIA 2011].

The Portuguese Independent Energy Services Regulator ERSE estimated an average growth rate for electricity demand in Portugal of 2.1%

for 2011.[8] In comparison, for the purposes of the CBA exercise, EDP Distribuição has assumed a (conservative) *estimated growth rate of energy* consumed of around 0.5% per year (for the next 20 years).

The calculation of benefits is very sensitive to the estimated growth rate of energy consumed as, *ceteris paribus*, a 1% increase of this variable in the InovGrid model would result in an increase of the NPV of around 16%. Figure 14 shows the result of the sensitivity analysis for the expected growth rate of energy consumption. The red curve shows the NPV for estimated growth rates from 0% to 5%. Clearly, the estimated growth of energy consumed affects the potential for energy efficiency benefits.

Note that for this exercise we did not take into account an increase in annual investments to support growing capacity, as is likely to be the case if a higher growth rate is anticipated. Therefore, the variations of the net benefit are likely to be lower in reality. However, rather than demonstrating that higher consumption rates translate into higher benefits, the point of this sensitivity test is to illustrate that this benefit is potentially more important for countries/regions with higher consumption rates/growth forecasts than for those with lower ones.

For the quantification of the value of reduced energy consumption, the retail value is an acceptable proxy.

Benefit(s) affected:

- *Reduced electricity technical losses* (reduction in technical losses at distribution level by consumption reduction and peak load transfer; reduction in technical losses at transport level due to consumption reduction);
- *Electricity savings* (benefits by consumption reduction; benefits peak load transfer).

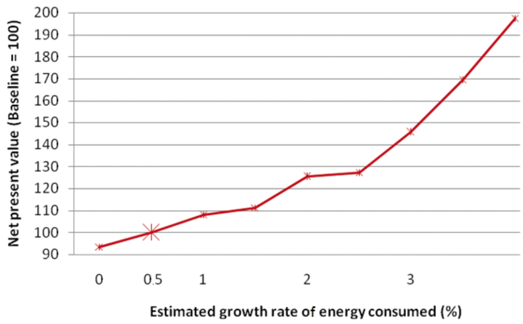


Figure 14: Example of impact of growth rate of energy consumption on expected net benefits.

[8] www.edp.pt

4.2 Peak load transfer

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 et al. 2010]. Therefore, 'shaving off' peak demand would postpone, reduce or even eliminate the need to install expensive and polluting peak generation capacity. Depending on the incentives a project provides for shifting peak load to off-peak hours (e.g. demand response through various forms of dynamic pricing), projects can achieve up to 30% peak load transfer [Faruqui et al. 2010]. Other recent experiences show an average peak load shaving of around 11% in the residential sector [VaasaETT 2011].

The InovGrid project provides some insights into how the peak load transfer can affect net benefits. A variation of 1 percentage point in the peak load transfer would lead to a 4.7% variation in net benefits.

Benefit(s) affected:

- *reduced electricity cost (peak load transfer)*
- *deferred distribution capacity investments.*

4.3 Percentage of electricity losses at T&D level

Figure 15 shows the average electric power T&D (transmission and distribution) losses (% of output, 2006-2008) of some EU Member States reported by the World Bank [World Bank 2011]. T&D losses vary significantly across Member States.

This variable can potentially alter the final net benefit considerably. In the InovGrid project, EDP Distribuição assumes *% electricity losses at T&D level* to be at 9.4% (around 8.1% at distribution level and around 1.3% at transmission level). A 1 percentage point increase in distribution level losses would result in an increase of 0.4% net benefit.

It is important to take into account network characteristics (grid-km per supplied GWh), the consumption mix at each voltage level and the percentage of underground v aerial network when analysing the current level of losses.

For example, countries with a high grid-km per supplied GWh (e.g. Portugal) cannot easily change losses through energy efficiency measures. The grid-km per supplied GWh is in fact a structural characteristic of a country's grid.

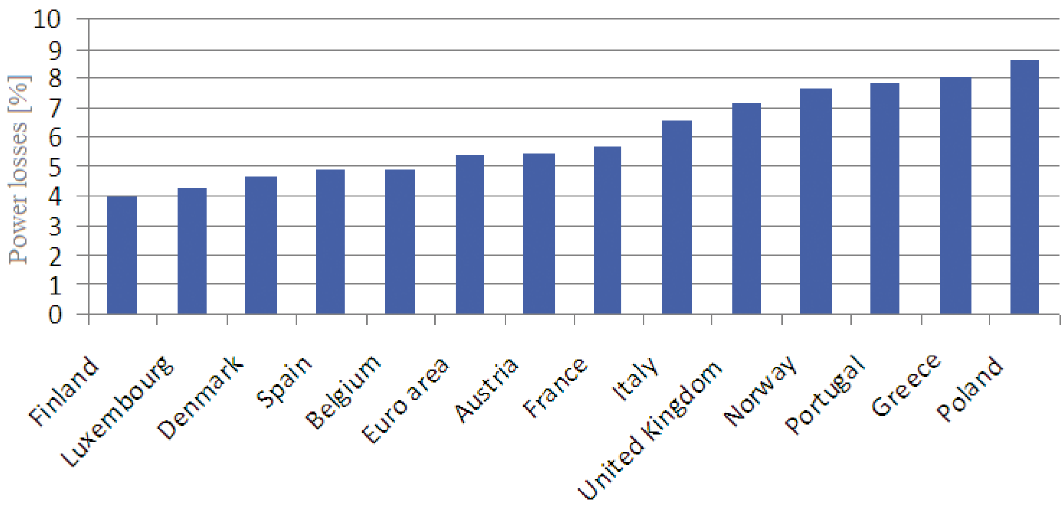


Figure 15: Electric power transmission and distribution losses (% of output, average 2006-2008).

Benefit(s) affected:

- *reduced electricity technical losses.*

4.4 Estimated number of non-supplied minutes

Figure 16 presents data on the estimated number of non-supplied minutes for selected Member States, published by the Council of European Energy Regulators [CEER 2008]. Benefits related to these figures are likely to vary greatly with the level of reliability of power supply in a country.

In the InovGrid project (in the baseline scenario), the assumed estimated number of non-supplied minutes per year is 120 (including both planned and unplanned interruptions). With regard to sensitivity, a variation of 5% of non-supplied minutes implies a variation in net benefit of about 0.2%. As already mentioned in Section 2.4, it is assumed that the reduction of outages is achieved through two different measures: improved observability of the network (smart metering infrastructure) and improved distribution automation (automatic network reconfiguration).

Benefit(s) affected:

- *reduced outage times* (benefits relating to recovered revenue associated with reduced outage times).

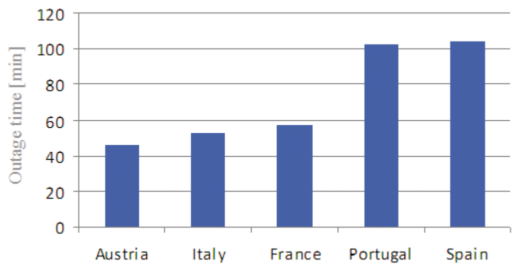


Figure 16: Minutes lost per year due to unplanned interruptions in 2007 (excluding exceptional events) [Source: CEER 2008].

4.5 Value of Lost Load

The Value of Lost Load (VOLL) expresses the economic cost per kWh of load not served. Table 5 gives the VOLL in different countries. The large differences in value depend, among other things, on the type of customer base in different geographical areas. Higher VOLL indicates higher shares of industrial or privileged consumers. This parameter should be carefully set, and details on how it has been chosen should be provided. Obviously, this variable will be significantly affected by the nature of customers' activity/business. In the InovGrid project, a VOLL of €1.5/kWh was used as an estimate of the cost to the economy per kWh of energy not supplied.

In countries with higher levels of VOLL, benefits based on this assumption are likely to be higher than those resulting from InovGrid's CBA, as in this model an increase of €1 in the VOLL would lead to a 3% increase in net benefit. Figure 17 depicts a sensitivity test that varies the value of service from its baseline value of €1.5/kWh up to €13/kWh.

Country	VOLL	Unit	Study
US	3-12	$/kWh	[Amin and Schewe 2007]
Ireland	12.9	€/kWh	[Leahy and Tol 2011]
Netherlands	8.6	€/kWh	[De Nooij et al. 2007]

Table 5: Estimated VOLL for selected countries.

Benefit(s) affected:

- *reduced outage times* (benefits relating to recovered revenue associated with reduced outage times).

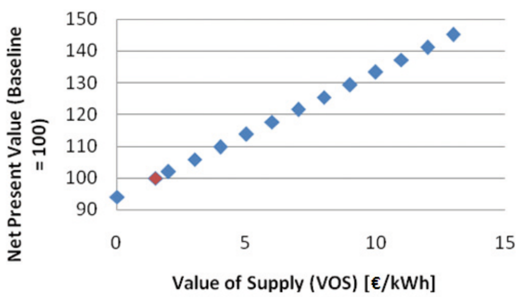


Figure 17: Example of sensitivity analysis on VOLL.

4.6 Discount rate

It has been suggested that all CBAs should be tested for sensitivity to the discount rate [UNEP 2009]. This analysis can be undertaken as described in Figure 18, which illustrates the relationship between the discount rate and the NPV for a range of discount rates (from 0% to 20%). In the hypothetical example in Figure 18, the red dots demarcate the NPV at a discount rate of 3% (left) and the IRR (right), which is where the curve crosses the horizontal line indicating an NPV of zero (at a discount rate of about 18%). It shows that the higher the discount rate, the lower the net benefit, as future benefits are increasingly undervalued with increasing discount rate.

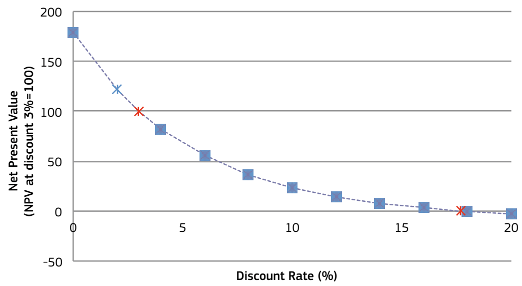


Figure 18: NPV curve – example of sensitivity analysis to discount rate.

4.7 Implementation schedule

The implementation schedule is a critical factor of the sensitivity analysis for the overall evaluation of the project's viability. The impact of the implementation schedule on overall net benefits may vary significantly. Figure 19 shows an example of a sensitivity analysis, indicating the changes in NPV with different implementation schedules of Smart Grid assets.

In the example, the schedule with the steepest implementation slope (i.e. fast roll-out) results in the lowest NPV. However, in other hypotheses and scenarios, the impact of the implementation schedule on the NPV may be reversed.

More generally, we stress that the definition of the 'optimal' implementation schedule should take into account several variables, such as:

- **Discount rate:** (see discussion in previous section);
- **Installation time frame and installation rate:** It is advisable to avoid installation peaks to allow for a better management of the supply chain and the installation teams;
- **Rural v urban:** Urban and rural installations may have different installation costs (euro/meter/day), and different implementation schedules for urban and rural installations (in terms of installed meter/day) may affect the final cost-benefit result.
- **Dispersed v concentrated:** Whether the deployment campaign is 'concentrated' (e.g. the entire network/city, then another, etc.) or 'scattered' (e.g. only customers with higher consumption in each network) may affect the smartness of the implemented Smart Grid functionalities and consequently the final cost-benefit result.
- **Technology maturity effect:** The installation of a technology with an expected high reduction of costs over the years (due to economy of scale) may suggest a slower implementation schedule to take advantage of future cost reductions.

A sensitivity analysis (see guideline 9) should be used to test the influence of these variables on the overall net benefit of the implementation.

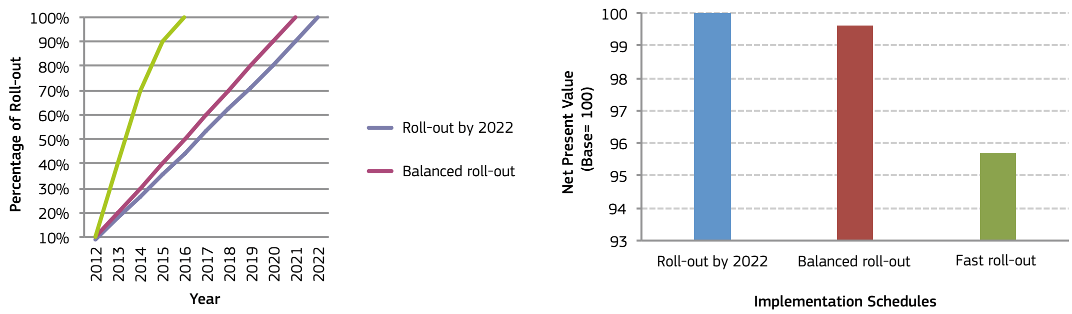


Figure 19: Sensitivity analysis of implementation schedule.

5. QUALITATIVE IMPACT ANALYSIS (NON-MONETARY APPRAISAL)

As mentioned earlier, an overall project assessment should address both quantifiable and non-quantifiable benefits (e.g. [Department of Transport, Victoria, Australia 2010; EC 2008]). There are certain benefits, like consumer participation or transparency of bills, which are difficult to monetise and include in a CBA. Other aspects of social impact should also be taken into account, e.g. job creation, strengthening of know-how and competitive positions, improvement of safety conditions and social acceptance.

Moreover, a CBA does not include potential future applications and functionalities or the resulting indirect benefits that are enabled by the Smart Grid project [CER 2011; Clastres 2011; Faruqui et al. 2010; WEF 2009, 2010]. For example, new indirect benefits can result from setting up a service platform on top of the infrastructure laid out in the InovGrid project. New services and products enabled by the InovGrid infrastructure may include energy efficiency applications, time of use tariffs, aggregation services (e.g. demand response, vehicle2grid services), smart appliances, electric mobility, etc. In turn, the set-up of these services and products fosters innovation and leverages new business ecosystems that may have a positive impact on the society at large but is difficult to quantify.

All these externalities represent important results that are enabled by the project and which have effects on the public or society at large. They are complex to quantify but should be taken into account in the project assessment, at least qualitatively, and complement the quantitative results of the CBA.

To conduct qualitative assessment (non-monetary) of additional benefits brought by the project (performance assessment of the project), it is important to consider:

- contribution of the project to different policy objectives – in Section 5.1 we provide a structured framework based on KPIs;
- Identification and appraisal of non-monetary impacts on society (e.g. environmental impact, social impact, job creation, consumer inclusion); these externalities should be expressed as much as possible in physical units in order 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 5.2 we provide a (non-exhaustive) list of externalities that may be applicable to Smart Grid projects.

The outcome of the overall qualitative impact analysis should therefore include (1) KPI-based scores of the project merits for different objectives, and (2) qualitative appraisal of foreseen externalities. The final outcome should be a vector like the one shown in Figure 20.

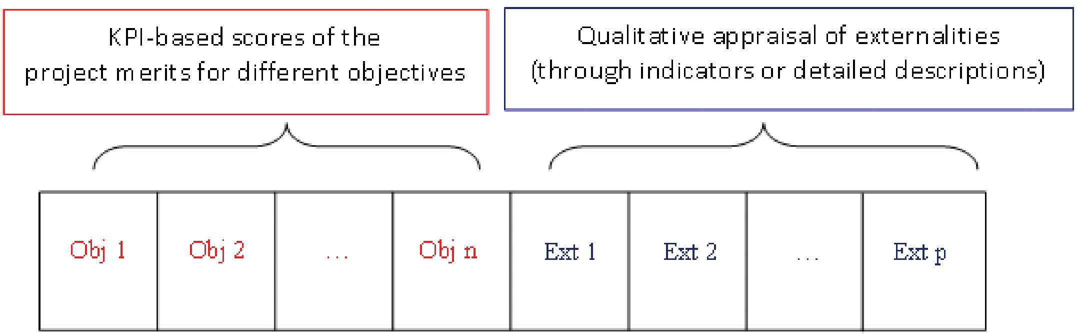


Figure 20: Outcome vector of the qualitative impact analysis with respect to policy objectives (Obj) and externalities (Ext).

Once the outcome vector is built, a technique should be devised to aggregate information, and expert judgement needs to be used to assess the overall impact. The outcome of the analysis should then be combined with the economic analysis through suitable weights to make a comprehensive project appraisal.

We stress that the analysis of non-monetary impacts of the project needs to be treated very cautiously, especially when it does not rely on quantitative indicators but on vague and subjective descriptive appraisals.

5.1 Performance Assessment – Deployment Merit

Different approaches have been proposed to define KPIs in order to qualitatively capture the deployment merit of the Smart Grid project (particularly with reference to policy goals and expected Smart Grid outcomes) [US DoE 2009a; 2009b; Dupont et al. 2010] and to complement the monetary quantification carried out in the CBA.

In discussing the list of benefits arising from the implementation of a Smart Grid, ERGEG [ERGEG 2010] and the EC Task Force [EC Task Force for Smart Grids 3 2010c] have proposed a comprehensive set of benefits and corresponding KPIs, which in many instances cannot be easily monetised, but which nevertheless provide a useful qualitative indication of the impact of the project (e.g. enhanced consumer awareness and participation in the market by new players create a market mechanism for new energy services such as energy efficiency or energy consulting for customers). These indicators aim at measuring the impact of Smart Grid projects toward the achievement of the ideal Smart Grid and of the policy goals behind it.

Building on this set of benefits and indicators, the EC Task Force [EC Task Force for Smart Grids 2010a, 2010c] has introduced an assessment approach to link KPI and functionalities and to capture the merit of the project deployment. This analysis is conceptually similar to step 3 of the original EPRI methodology [EPRI 2010], which was skipped in our CBA.

Table 6: Example of a sub-set of the merit deployment matrix to assess services and benefits.

	SERVICES						
Benefits and Key Performance Indicators	**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**	**TOTAL SUM FOR ASSESSMENT**
Increased sustainability							
Quantified reduction of carbon emissions	Deployment of Smart Meters and associated IT systems 0.1	Use of the DTC, interaction with EBs and supporting IT systems 0.3		Remote network management 0.2		Smart meter, Direct/Indirect messaging system, web portal, in-house display 0.1	0.7
Environmental impacts of grid infrastructure	Deployment of Smart Meters and associated IT systems 0.2	Use of the DTC, interaction with Smart Meters and supporting IT systems 0.3		Remote network management 0.2			0.7
Quantified reduction of accidents and risks	Deployment of Smart Meters and associated IT systems 0.2	Use of the DTC, interaction with Smart Meters and supporting IT systems 0.3					0.5
SUM TOTAL	0.5	0.9	0.0	0.4	0.0	0.1	

The assessment framework proposed by [EC Task Force for Smart Grids 2010c] is based on a merit deployment matrix (see Annex VII), where benefits and corresponding KPIs are given in the rows, whereas functionalities (which are grouped into homogeneous clusters called services) are given in the columns:

		Functionality j
Benefit i	KPI^i_1	0-1
	KPI^i_2	0-1
	KPI^i_3	0-1
	…	…

For each project, the matrix is completed in two main steps:

- identify links between benefits/KPI and functionalities. Select the corresponding cell;
- for each cell, explain how the link between benefits/KPI and functionalities is achieved in the project. Assign a weight (in the range 0-1) to quantify how strong and relevant the link is.

By summing up the cells along the columns, it is possible to quantify the impact of the project in terms of functionalities, whereas by summing up the cells along the rows, it is possible to quantify the impact of the project in terms of benefits.

The use of the Task Force assessment framework is a possible approach to qualitatively capture the deployment merit of the project in a more systematic way.

For the sake of illustration, Table 6 gives a sub-set of the merit deployment matrix of the InovGrid project. Adding up all columns and rows of the whole deployment matrix (not done here for the sake of brevity) results in the graphs in Figure 21. The areas spanned in the service/functionality and benefit planes represent the deployment merit of the project: the larger the area in the graph, the greater the project impact.

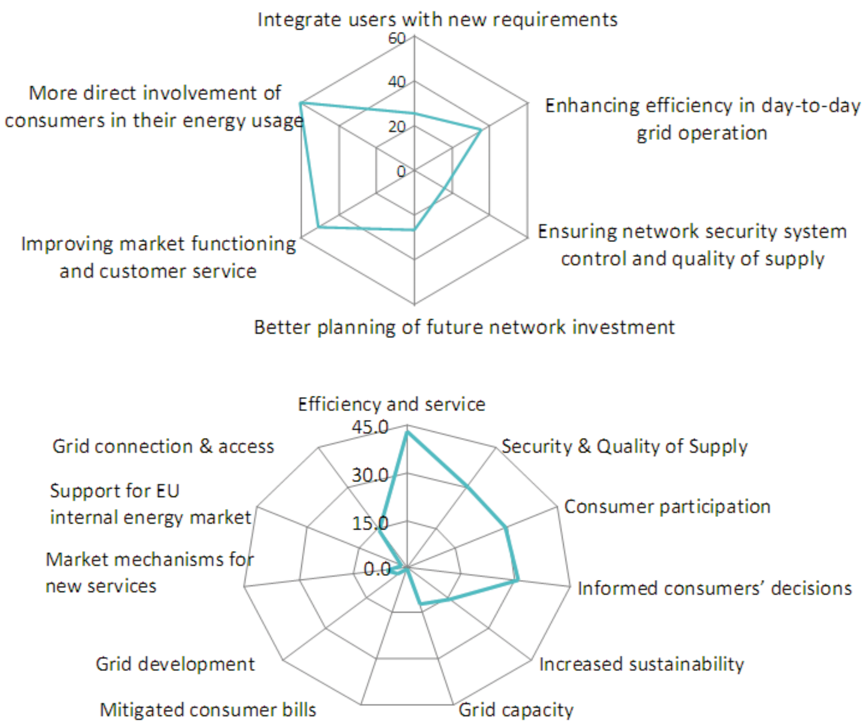
The outcome of the merit deployment assessment is therefore a vector composed of the score of the project in terms of different objectives (either benefits or services/functionalities). The contribution to each of the objectives may then be weighted according to the relative importance given to them by the decision-maker.

5.2. Externalities and social impact

Apart from addressing the deployment merit of a project, the qualitative analysis should granularly identify and assess all costs and benefits that spill over from the project into society and that cannot be monetised and included in the economic analysis (externalities). All externalities should be listed and expressed in physical terms (e.g. use decibels to quantify noise reduction benefit). We recommend defining an indicator for each externality to make the assessment as objective and rigorous as possible. The choice and calculation of each indicator should be transparently illustrated and motivated. Where the calculation of an indicator is not feasible, a detailed description of the estimated impacts of the project should be provided to give decision-makers the whole range of elements for the appraisal. Another option is to use a 'benefit transfer' approach, i.e. to use values previously estimated in projects with similar conditions as proxies for the same benefits in the project under analysis [EC 2008].

Social impacts represent a significant portion of the possible externalities of a Smart Grid project. It is expected that society at large may benefit from the Smart Grid through the resulting improvement in areas like national security, environmental conditions, public health or economic growth [NETL 2010]. Increased national security, for instance, can be achieved by reducing a country's dependence on foreign oil through various combinations of conservation, demand response and reduced T&D losses. Similarly, Smart Grids can contribute to improving public health through the Smart Grid's ability to support an intensified use of electric vehicles (EVs), thereby reducing

Figure 21: Example of project impact across services/functionalities (a) and benefits (b).



vehicle emissions from combustion vehicles. Although difficult to monetise, the social impact of Smart Grid implementation is significant. These benefits are complex to evaluate, but understanding their importance is essential for grasping the (entire) value of Smart Grids. Therefore, in the remainder of this section, we will present some of the areas worth considering in the assessment of the social impact of a Smart Grid project.

Jobs

One important challenge is to evaluate the impact on jobs along the whole value chain and to identify the segments where jobs may be lost or gained. The analysis may include an estimation of the number of jobs created/lost in the supply and operational value chain.

The first direct impact is on utility jobs created by Smart Grid projects that will require new skills, and on utility personnel (e.g. meter readers) who will need to be retrained for other roles. A second direct impact is on new jobs for service providers working toward the implementation of the project.

Other categories that may 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, EV manufacturers and suppliers, etc.).

Safety

This analysis should 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 meters).

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

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

Environmental impact

This analysis may consider the impacts on the environment in terms of noise (noise reduction or noise increase) and landscape changes. If numerical indicators cannot be calculated, the project appraisal may try to include a verbal description of the expected (positive or negative) impacts.

If a monetisation of the reduced CO_2 and air pollutant emissions has not been carried out in the CBA, these impacts should be taken into account here, preferably expressed in physical units (e.g. tons or decibels).

Social acceptance

In several instances, social acceptance is key to the successful implementation of Smart Grid projects. Social resistance may arise due to concerns over transparency, fair benefit sharing or environmental impact. If applicable, an assessment of the level of social resistance (or participation) to the project should be presented, including a description of the means adopted to ensure social acceptance and their effectiveness.

Time lost/saved by consumers

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

For example, in a smart metering installation project, consumers may save time through fewer complaints as bills are more accurate and transparent or they may save time by having their tariff plan changed remotely.

Enabling new services and applications and market entry for third parties

This analysis should try to assess which new services and applications may be enabled by the implementation of the Smart Grid project under consideration. It should assess the impact of the projects in creating new opportunities for third parties (e.g. aggregators, telecom companies) to enter the electricity market.

Ageing workforce – gap in skills and personnel

This analysis may address the impact of the project in reducing the gap in skills and personnel due to the 'greying workforce, i.e. shortages of qualified technical personnel due to skilled technicians reaching retirement age. It may also analyse the impact of the project in creating new skills and boosting know-how and competitiveness.

Privacy and security

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

6. SUMMARY: GUIDELINES

- In this chapter, we provide guidelines for performing a comprehensive CBA assessment (Figure 22). The ten guidelines cover four main macro-steps, illustrated in detail in this study: definition of assumptions, critical variables and boundary conditions tailored to the specific geographical/regulatory context (Chapter 2);
- implementation of the CBA (Chapter 3);
- implementation of a sensitivity analysis to analyse the influences of key variables on the CBA (Chapter 4);
- integration of the CBA with qualitative assessment of the merit of the deployment, externalities and social impact (Chapter 5).

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.

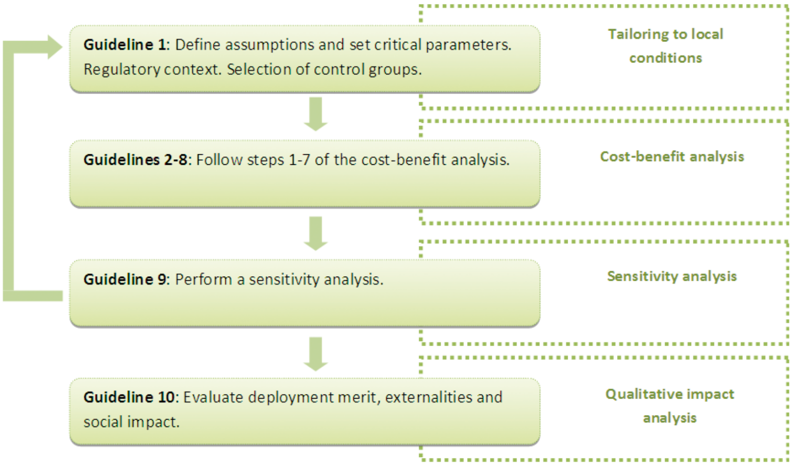


Figure 22: Guidelines flow chart.

I. Tailoring to local conditions

Guideline 1 – Define assumptions and set critical parameters

Critical parameters in Smart Grid projects that need to be chosen include (non-exhaustive list):

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	€
Life expectancy of installed systems	Number of years
Installation costs	€
Carbon costs	€/ton
Inflation rate	%
Cost reduction associated with technology maturity	%
Implementation schedule	% asset deployment/year
Percentage of asset deployment in rural v urban areas	%

Table 7: Non-exhaustive list of variables/ parameters to define.

II. Cost-benefit analysis

Guideline 2 – Review and describe the technologies, elements and goals of the project

The first step is to provide a main summary and to describe the elements and goals of the project. This may involve answering (some of) the following questions:

- What are the project's overall purposes and solutions?
- What are the main components/technologies deployed?
- What are the functionalities of the main components?

In the definition of the boundaries of the CBA, Smart Grid investments and applications should be considered together only if they need to function together.

Guideline 3 – Map assets into functionalities

Determine what Smart Grid functionalities are activated by the assets proposed by the project. Consider each asset individually and contemplate how it could contribute to any of the functionalities. Smart Grid assets provide different types of functionalities that enable Smart Grid benefits. If the assets deployed and/or functionalities enabled by the project are unclear, the analysis is likely to be incomplete.

To complete this step, consider the assets of the project. 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.

Guideline 4 – Map functionalities on to benefits

Link the functionalities identified in Step 2 to the (potential) benefits they provide. Consider each functionality individually and contemplate how it could contribute to any of the benefits. This analysis should continue until all applicable functionalities are considered.

Guideline 5 – Establish the baseline

The objective of the establishment of the project baseline is to formally define the 'control state' that reflects the system condition which would have occurred had the project not taken place. This is the baseline situation against 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 BaU scenario on the one hand and those associated with the implementation of the project on the other. In a situation where costs and benefits are related to projected behavioural impacts of electricity consumers, baselines should preferably be a 'control group' of comparable customers, randomly selected from the target population.

The CBA should refer to the useful life of the Smart Grid investments, which indicates the period of time when the installed Smart Grid system is intended to reliably perform its designed functions.

Guideline 6 – Monetise the benefits and identify the beneficiaries

Identify, collect and report the data required for the quantification and monetisation of the benefits. Key assumptions and the level of estimation uncertainty should be clearly documented.

Some recommendations:

- benefits should represent those actually resulting from the project;
- benefits should be significant (meaningful impact), relevant to the analysis and transparent in their quantification and monetisation;
- 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 with the benefit estimation should be clearly stated and documented;
- take into consideration the data requirements of the CBA in the design phase of the project in order to make sure that all data necessary for the CBA can be collected;
- the beneficiaries (consumers, system operators, society, retailers, etc.) associated with each benefit should be identified, as far as 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.

Guideline 7 – Identify and quantify the costs

Estimate the relevant costs. Some costs can be measured directly by the company, while others are typically easy to estimate since their prices, or very good proxies, can be easily obtained in the market place. The costs of a project are those costs incurred to implement the project, relative to the baseline. The costs should include capital, ongoing/operational and transitional costs.

Collecting information on the project's costs allows the calculation of a project's return on investment, which shows whether it is positive, and if so, when the project will break even. Even though identifying these costs is not usually a difficult exercise, it does require meticulous itemisation of all important costs.

Some recommendations:

- costs should *only* be those necessary and sufficient for the purpose of implementing the Smart Grid measure(s);
- 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, as far as 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;
- good practices to estimate costs include a market consultation;
- use approved accounting procedures for handling capital costs, debit, depreciation and taxes;
- the choice of the amortisation rate depends on the technology ageing speed and on the assumptions about the market conditions. If the market imposes high innovation turnover for some assets (e.g. IT) or if uncertainty exists, the amortisation rate has to be set conservatively high.

Guideline 8 – Compare costs and benefits

Once costs and benefits have been estimated, there are several ways to compare them in order to evaluate the cost-effectiveness of the project. The most common methods are *annual comparison, cumulative comparison, NPV* and *benefit-cost ratio*.

III. Sensitivity analysis

Guideline 9 – Sensitivity analysis

Perform a sensitivity analysis. Sensitivity analysis is a method used for investigating the impact of changes in project variables on the baseline scenario. Typically, mainly adverse changes are taken into consideration. The sensitivity analysis assists in identifying key variables that influence the project's costs and benefits, and demonstrates the consequences of likely adverse changes in these key variables. For example, it could demonstrate how the NPV would change with the increase/decrease of a particular variable.

A sensitivity analysis can aim at varying major benefits and costs one at a time or in combination. This technique will help project promoters assess whether and how project decisions could be affected by such changes and will help them identify actions that could mitigate possible adverse effects on the project.

Good candidates for inclusion are variables with a wide range of potential values and/or which are more subjective in nature (e.g. discount rate, estimation of peak transfer).

IV. Performance assessment, externalities and social impact

Guideline 10 – Qualitative impact analysis: non-monetary appraisal

The CBA should be complemented by a qualitative impact analysis, i.e. a qualitative estimation of additional costs and benefits that cannot be monetised and included in a CBA. The qualitative impact analysis should include (1) deployment merit of the project (performance assessment); (2) externalities, with particular reference to social impacts.

Performance assessment – KPI-based project merit deployment

Fill in the benefit-functionality matrix ([EC Task Force for Smart Grids 2010c], Annex VII) and draw the corresponding spider diagrams. We recommend that at the national level, a single institutional body (e.g. national regulator) should be in charge of monitoring this exercise, and they should clearly document choices and assumptions made in filling in the matrix.

The outcome of this performance assessment is a vector of KPI-based scores representing the merit of the project for different objectives.

Externalities and social impacts

Identify externalities and express them in physical terms (e.g. use decibels to quantify noise reduction benefit). The choice and the calculation of each indicator should be transparently illustrated and motivated. Where the calculation of an indicator is not feasible, a detailed description of the estimated impacts of the project should be provided to give decision-makers the whole range of elements for the appraisal.

Social impacts typically represent a significant portion of the project externalities. Some areas of focus include:

- job impact
- safety
- environmental impact
- social acceptance
- time lost/saved by consumers
- enabling new services and applications and market entry to third parties
- reduction of the gap in skills and personnel
- privacy and security.

The outcome of the externality assessment (including social impacts) should then be integrated into the KPI-based scores of the performance assessment. It is then necessary to specify weights to combine the different elements of the analysis. The weights should reflect the relative importance of each objective in the decision-maker's view.

Combining economic and qualitative analysis

Once the outcomes of the economic analysis and of the qualitative impact analysis have been assessed, suitable weighting factors to combine the quantitative and qualitative analysis should be advised. The choice of weighting factors needs to be explained clearly and convincingly.

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ANNEX I – LIST OF BENEFITS FOR COST-BENEFIT ANALYSIS IN EPRI METHODOLOGY [EPRI 2010]

Optimised Generator Operation

Better forecasting and monitoring of load and grid performance would enable grid operators to dispatch a more efficient mix of generation that could be optimised to reduce cost.

Reduced Generation Capacity Investments

Utilities and grid operators ensure that generation capacity can serve the maximum amount of load that planning and operations forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Reducing peak demand and flattening the load curve should reduce the generation capacity required to service load and lead to cheaper electricity for customers.

Reduced Ancillary Service Cost

Ancillary services, including spinning reserve and frequency regulation, could be reduced if generators could more closely follow load. Ancillary services are necessary to ensure the reliable and efficient operation of the grid. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. The functions that provide this benefit reduce ancillary cost through improving the information available to grid operators.

Reduced Congestion Cost

Transmission congestion is a phenomenon that occurs in electric power markets. It happens when scheduled market transactions (generation and load) result in power flow over a transmission element that exceeds the available capacity for that element. Since grid operators must ensure that physical overloads do not occur, they will dispatch generation so as to prevent them. The functions that provide this benefit either provide lower cost energy or allow the grid operator to manage the flow of electricity around constrained interfaces.

Deferred Transmission Capacity Investments

Reducing the load and stress on transmission elements increases asset utilisation and reduces the potential need for upgrades. Closer monitoring, rerouting power flow, and reducing fault current may enable utilities to defer upgrades on lines and transformers.

Deferred Distribution Capacity Investments

As with transmission lines, closer monitoring and load management on distribution feeders could potentially extend the time before upgrades or capacity additions are required.

Reduced Equipment Failures

Reducing mechanical stresses on equipment increases service life and reduces the probability of premature failure.

Reduced Distribution Equipment Maintenance Cost

The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure that they maintain equipment sufficiently, and identify failure precursors, some utilities may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment.

Reduced Distribution Operations Cost

Automated or remote controlled operation of capacitor banks and feeder switches eliminates the need to send a line worker or crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle.

Reduced Meter Reading Cost

Automated Meter Reading (AMR) equipment eliminates the need to send someone to each location to read the meter manually.

Reduced Electricity Theft

Smart meters can typically detect tampering. Moreover, a meter data management system can analyse customer usage to identify patterns that could indicate diversion.

Reduced Electricity Losses

The functions listed help manage peak feeder loads, locate electricity production closer to the load and ensure that customer voltages remain within service tolerances, while minimising the amount of reactive power provided. These improve the power factor and reduce line losses for a given load served.

Reduced Electricity Cost

The functions listed could help alter customer usage patterns (demand response with price signals or direct load control), or help reduce the cost of electricity during peak times through either production (distributed generation) or storage.

Reduced Sustained Outages

Reduces the likelihood that there will be an outage, and allows the system to be reconfigured on the fly to help in restoring service to as many customers as possible. A sustained outage is one lasting more than 5 minutes, excluding major outages and wide-scale outages (defined below). The benefit to consumers is based on the value of service (VOS).

Reduced Major Outages

A major outage is defined using the beta method, according to IEEE Std 1366-2003 [IEEE Power Engineering Society 2004]. The functions listed (see [EPRI 2010]) can isolate portions of the system that include distributed generation so that customers will be served by the distributed generation until the utility can restore service to the area.

Reduced Restoration Cost

The functions that provide these benefits cause fewer outages, which result in fewer restoration costs. These costs can include line crew labour/material/equipment, support services such as logistics, call centres, media relations and other professional staff time and material associated with service restoration.

Reduced Momentary Outages

By locating faults or adding electricity storage, momentary outages could be reduced or eliminated. Moreover, fewer customers on the same or adjacent distribution feeders would experience the momentary interruptions associated with reclosing. Momentary outages last less than 5 minutes. The benefit to consumers is based on the VOS.

Reduced Sags and Swells

Locating high impedance faults more quickly and precisely, and adding electricity storage functions will reduce the frequency and severity of the voltage fluctuations that they can cause. Moreover, fewer customers on the same or adjacent distribution feeders would experience the voltage fluctuation caused by the fault.

Reduced CO_2 Emissions

Functions that provide this benefit can improve the performance for end-users in many aspects. These improvements translate into a reduction in CO_2 emissions produced by fossil-based electricity generators.

Reduced SO_x, NO_x and PM-10 Emissions

Functions that provide these benefits can improve the performance for end-users in many aspects. These improvements translate into a reduction in SOx, NOx and PM-10 emissions produced by fossil-based electricity generators

Reduced Oil Usage

The functions that provide this benefit eliminate the need to send a line worker or crew to the switch location in order to operate it. This reduces the fuel consumed by a service vehicle or line truck. For plug-in electric vehicles (PEVs), the electrical energy used by PEVs displaces the equivalent amount of oil.

Reduced Wide-scale Blackouts

The functions listed will give grid operators a better picture of the bulk power system and allow them to better coordinate resources and operations between regions. This will reduce the probability of wide-scale regional blackouts.

ANNEX II – A GUIDE TO THE CALCULATION OF BENEFITS

This chapter provides a description of a possible (non-exhaustive) list of formulae for the calculation of benefits. Benefits should be calculated for each year of the time horizon of the analysis.

a. Reduction in meter reading and operation costs

This benefit comprises two parts: reduced meter operation costs and reduced meter reading costs. In order to determine the value of this benefit, 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 operation costs:

Value (€) = [Estimated cost reductions with remote meter operations (€)]$_{SGproject}$ *– [Estimated cost reductions with remote meter operations (€/year) * Communications failure rate (%/100)]*$_{SGproject}$

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 operation costs, one should take into account situations with communication failure and meter operations that will require local meter operations, such as in the case of breakdown or malfunction, meter replacement or installation in 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 (€)]*$_{SGproject}$

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 (€)]$_{SGproject}$*= [# of clients in LV (# clients) * % of clients not included 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 may still be unable to obtain remote reading. In the above formula we have considered two categories of clients requiring local meter-reading services: (1) clients not included in the roll-out and (2) 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 (€)]*$_{SGproject}$

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 with 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 (€)]*$_{SGproject}$

The estimated cost reduction refers to a reduction in customer claims to call centres regarding billing based on inaccurate meter readings. 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) may take place and negatively impact this benefit.

b. Reduced operational and maintenance cost

To calculate these benefits, the scenario should track the distribution operational and maintenance cost before and after the Smart Grid project 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 (€)]*$_{SGproject}$

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

Reduced cost of equipment breakdowns:

Value (€) = [Cost of equipment breakdowns (€)]$_{Baseline}$ *– [Cost of equipment breakdowns (€)]*$_{SGproject}$

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 amount of equipment requiring replacement and the average cost of the equipment.

c. Deferred distribution capacity investments

The assumption underlying the monetisation of this benefit is that the implementation of Smart Grid solutions will potentially allow a reduction in the 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 in 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.

Monetisation 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 monetisation formulae consider the impact on the amount of distribution capacity investments of asset remuneration on the one hand and of asset amortisation 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 of 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 amortisation:

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

This calculation takes into consideration the deferral of the amortisations 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 amortisation).

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 by 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 Smart Grid project implementation. For example, in a smart metering project, 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.

The potential for deferred cost of capacity (due to peak load shifting) needs to be calculated separately. This calculation should consider only those networks where the peak corresponds with the general peak (e.g. 6 pm) 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 monetisation 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] * % 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 monetisation 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 monetisation of this benefit is that the Smart Grid scenario will potentially allow a reduction in 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 in 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, several Smart Grid functions can contribute to loss reductions, and scenarios that demonstrate more than one of these at the same time will see compounded effects. The total benefit of reduced power losses comprises different sub-categories of benefits. They are related to (1) energy efficiency (consumption reduction and peak load transfer at the distribution level, (2) improved balancing between phases, (3) increased distributed (micro-generation), (4) voltage control, and (5) consumption reduction at the transmission level.

One way of estimating technical loss reductions is the use of simulators. Another way 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 (MWh) * Estimated % consumption reduction with Smart Grid scenario (%/100)*

In *ex-ante* calculations, a confident estimate of consumption reduction for domestic clients is difficult. Assumptions on consumption reduction can be made by analysing international benchmarks and recent studies. They show that a Smart Grid infrastructure may lead 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 (MWh)*

The introduction of new tariff plans and detailed real-time information about consumption is expected to incentivise clients to shift part of their consumption to off-peak periods. The percentage of peak load transfer needs to be estimated. One way of monetising 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 project 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 (€) = % 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 (€) = % 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 (€) = % 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 smart metering systems, it may emerge that in some cases clients were consuming more electricity than the amount contracted. As a consequence, an increase in 'contracted power' may be observed and extra monetary benefit may 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 (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 or 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 to 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 (€)/ Minutes per year (#/year) * Average non-supplied minutes/year (#/year) * % decrease in outage time (%)*

While the value of a 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 in client compensations*

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

j. Reduced CO_2 emissions and reduced fossil fuel usage

CO_2 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 CO_2 emissions is related to the reduction in the total mileage of DSOs' operational fleet and the consequent savings on litres of fuels and CO_2 emissions due to remote meter readings and remote network operations.

In those cases where the analysis permits the calculation of carbon costs, the recommendation is to use the projected EU Emission Trading Scheme carbon prices in the Commission reference scenario up to 2050 as a minimum lower bound, assuming implementation of existing legislation but not decarbonisation.[9]

Benefit of 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)]$_{SGproject}$*

This calculation monetises the reduced CO_2 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 CO_2 content of the electricity produced (tons/MWh). In the definition of this value, the generation sources that are affected by the reduction in line losses should typically be taken into account.

9 Annex 7.10 of SEC (2011) 288 final: Commission staff working document Impact Assessment (http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SEC:2011:0288:FIN:EN:PDF).

Reduced CO_2 emissions due to wider diffusion of low carbon generation sources

*Value (€) = [CO_2 Emissions (tons) * Value of CO_2 (€/ton)]* $_{Baseline}$ *– [CO_2 Emissions (tons) * Value of CO_2 (€/ton)]* $_{SGproject}$

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 Smart Grid deployment and the wider diffusion of low carbon generation sources.

Benefit of reduced CO_2 emissions:

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

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

Benefit of reduced oil usage:

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

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

k. Reduction of air pollution (particulate matters, NO_x, SO_2)

For the 'cost of air pollutants' (particulate matters, NO_x, SO_2), the recommendation is to consult the CAFE (Clean Air For Europe) quantification process for air quality benefits[10]. Other useful information can be found in [EC 2010d].

Reduced air pollutant emissions thanks to wider diffusion of low carbon generation sources (enabled by the Smart Grid project)

For each pollutant:

*Value (€) = [Air pollutant emissions (unit) * Cost of air pollutant (€/unit)]* $_{Baseline}$ *– [Air pollutant emissions (unit) * Cost of air pollutant (€/unit)]* $_{SGproject}$

Reduced air pollutant 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)]* $_{SGproject}$

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

For each pollutant:

*Value (€) = [Fleet mileage (km) * Air pollutant emissions (unit/km) * Cost of air pollutant (€/unit)] Baseline – [Fleet mileage (km) * Air pollutant emissions (unit/km) * Cost of air pollutant (€/unit)]SGproject*

For the quantification of this benefit (e.g. due to reduced mileage of truck rolls of field personnel and of meter-reading operators), the recommendation is to consult the Clean Vehicles 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.

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

ANNEX III – 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 small-scale 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: Optimise 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 non-technical 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, transmission system operators.

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 the required time

D. Better planning of future network investment

Outcome: Collection and use of data to enable more accurate modelling 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 Distributed Generation, 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, application and service providers.

Corresponding functionalities:

20. Participation of all connected generators in the electricity market
21. Participation of virtual power plants 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 grid users with individual advance notice of planned interruptions
27. Improve customer level reporting in the case 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 players in the electricity market through demand response programmes and a more effective management of variable and non-programmable generation. Obtain the consequent system benefits: peak reduction, reduced network investments, ability to integrate more intermittent generation.

Provider: Suppliers (with metering operators and DSOs), Energy Service Companies.

Primary beneficiaries: Consumers, generators.

The only primary beneficiary who 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 on 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 IV – KEY PERFORMANCE INDICATORS AND BENEFITS [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 with 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 optimised use of capital and assets

Adequate grid connection and access for all kinds 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 to 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 supply and grid operation

20. Level of losses in transmission and in distribution networks (absolute or percentage).[11] Storage induces losses, but active flow control also increases losses

[11] For comparison purposes, 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 possible conflict between, for example, aiming for higher utilisation of network elements (loading) and higher losses, should be considered.

21. Ratio between minimum and maximum electricity demand within a defined time period (e.g. one day, one week)[12]

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, distributed energy sources (DER) hosting capacity in distribution grids)

Effective support of transnational electricity markets by load flow control to alleviate loop flows 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 cross-border exchanges and congestion management guidelines

28. Congestion rents across interconnections

Coordinated grid development through common European, regional and local grid planning to optimise transmission grid infrastructure

29. Impact of congestion on outcomes and prices of national/regional markets

30. Societal benefit-cost ratio of a proposed infrastructure investment

31. Overall welfare increase, i.e. always running the cheapest generators to supply the actual demand (this is also an indicator for benefit (6) above)

32. Time for licensing/authorisation of a new electricity transmission infrastructure

33. Time for construction (i.e. after authorisation) of a new electricity transmission infrastructure

Enhanced consumer awareness and participation in the market by new players

34. Demand side participation in electricity markets and in energy efficiency measures

35. Percentage of consumers on (opt-in) time-of-use/critical peak/real-time dynamic pricing

36. Measured modifications of electricity consumption patterns after new (opt-in) pricing schemes

37. Percentage of users available to behave as interruptible load

38. Percentage of load demand participating in market-like schemes for demand flexibility

39. Percentage participation of users connected to lower voltage levels to ancillary services

Enable consumers to make informed decisions related to their energy to meet the EU Energy Efficiency targets

40. Base-to-peak load ratio

41. Relation between power demand and market price for electricity

42. Consumers can comprehend their actual energy consumption and receive, understand and act on free information they need/ask for

43. 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

44. Ability to participate in relevant energy market to purchase and/or sell electricity

45. Coherent link is established between the energy prices and consumer behaviour

[12] For comparison purposes, a structural difference in the indicator should be taken into account due to, for example, electrical heating and weather conditions, shares of industrial and domestic loads.

Create a market mechanism for new energy services such as energy efficiency or energy consulting for customers

46. 'Simple' and/or automated changes to consumers' energy consumption in reply to demand/response signals are enabled

47. Data ownership is clearly defined and data processes in place to allow for service providers to be active with customer consent

48. Physical grid-related data are available in an accessible form

49. Transparency of physical connection authorisation, requirements and charges

50. 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

51. Transparent, robust processes to assess whether the benefits of implementation exceed the costs in each area where roll-out is considered, and a commitment to act on the findings by all the involved parties

52. Regulatory mechanisms that ensure that these benefits are appropriately reflected in consumer bills and do not simply result in windfall profits for the industry

53. New smart tariffs (energy prices) that deliver tangible benefits to consumers or society in a progressive way

54. Market design is compatible with the way consumers use the grid

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

SCENARIO ASSETS										
								1. Facilitate connections at all voltages / locations for any kind of devices	Integrate users with new requirements	Services and Functionalities
								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	Enhancing efficiency in day-to-day grid operation	
								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	Ensuring network security, system control and quality of supply	
								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 the required time		
								17. Better models of DG, storage, flexible loads, ancillary services	Better planning of future network investment	
								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	Improving market functioning and customer service	
								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 grid users with individual advance notice for planned interruptions		
								27. Improve customer level reporting in the case of interruptions		
								28. Sufficient frequency of meter readings	More direct involvement of consumers in their energy usage	
								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 – (EPRI) BENEFITS-FUNCTIONALITIES MATRIX (CBA STEP 3)

		Services and functionalities (Annex III)		
		Functionality 1	...	Functionality 33
Economic	Optimised 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 to Contracted Power			
	Reduced Electricity Cost			
Reliability	Reduced Sustained Outages			
	Reduced Major Outages			
	Reduced Restoration Cost			
	Reduced Momentary Outages			
	Reduced Sags and Swells			
Environmental	Reduced CO_2 Emissions			
	Reduced SOx, NOx, and PM-10 Emissions			
Security	Reduced Oil Usage			
	Reduced Wide-scale Blackouts			

ANNEX VII – MERIT DEPLOYMENT MATRIX [EC TASK FORCE FOR SMART GRIDS 2010C]

		Services and functionalities (Annex III)			
		Functionality 1	...	Functionality 33	Total sum: rows
Benefits and key performance indicators (Annex IV)	KPI 1				Sum row 1
	...				
	KPI 54				Sum row 54
	Total sum: columns	Sum column 1	...	Sum column 33	

ANNEX VIII – MODIFICATIONS TO THE ORIGINAL EPRI METHODOLOGY

The CBA methodology proposed in this study is based on the EPRI methodology. By concretely testing the EPRI methodology on a real case study, modifications to fit the European context have been proposed:

- Step 3 (*Assess the principal characteristics of the Smart Grid to which the project contributes*) of the EPRI methodology [EPRI 2010] has been skipped. This step is intended to measure the smartness of a Smart Grid project and the merit of its deployment. In this study, the merit deployment analysis is based on the assessment framework proposed in [EC Task Force for Smart Grids 2010c] and is proposed as a complement to the CBA (see Chapter 4).

- In steps 2 (*Identify the functions*) and 4 (*Map each function onto a standardised set of benefit types*) [EPRI 2010], functions have been replaced by (European) functionalities [EC Task Force for Smart Grids 2010a], in order to limit the set of new categories and definitions. It is worth mentioning that functions and functionalities cannot be directly compared. Functions have a very strong technical dimension (e.g. fault current limiter, feeder switching). Functionalities represent more general capabilities of the Smart Grid and do not focus on specific technology. They provide an intuitive description of what the project is about. This may help project coordinators to identify the key capabilities of the projects and hence the resulting benefits. We think that the use of functionalities is a useful tool for assessing which areas of the Smart Grid the project is contributing to and for identifying benefits and impacts.

- Steps 6, 7, 8 (*Identification of benefits, quantification of benefits and monetisation of benefits*) have been grouped together. They are considered as sub-steps of the single step 'Quantification of benefits'.

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 anticipated future cash flows (which may 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 period 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 the 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 (IRR): 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, which 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 programme.

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 cost: 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.

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Abstract

The goal of this report is to provide guidance and advice for conducting cost-benefit analyses of Smart Grid projects.

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

A European Smart Grid project (InovGrid, implemented in Portugal) has been used as a case study to fine-tune and illustrate the proposed assessment framework.

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