FlexPlan

Advanced methodology and tools taking advantage of storage and FLEXibility in transmission and distribution grid PLANning

Guideline for the compliance of network planning tool with EU overall strategies and regulatory conditions

D6.1

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About FlexPlan

The FlexPlan project aims at establishing a new grid planning methodology considering the opportunity to introduce new storage and flexibility resources in electricity transmission and distribution grids as an alternative to building new grid elements. This is in line with the goals and principles of the new EC package *Clean Energy for all Europeans,* which emphasizes the potential usage of flexibility sources in the phases of grid planning and operation as alternative to grid expansion. In sight of this, FlexPlan creates a new innovative grid planning tool whose ambition is to go beyond the state of the art of planning methodologies, by including the following innovative features: integrated T&D planning, full inclusion of environmental analysis, probabilistic contingency methodologies replacing the N-1 criterion as well as optimal planning decision over several decades. However, FlexPlan is not limited to building a new tool but it also uses it to analyse six regional cases covering nearly the whole European continent, aimed at demonstrating the application of the tool on real scenarios as well as at casting a view on grid planning in Europe till 2050. In this way, the FlexPlan project tries to answer the question of which role flexibility could play and how its usage can contribute to reduce planning investments yet maintaining (at least) the current system security levels. The project ends up formulating guidelines for regulators and for the planning offices of TSOs and DSOs. The consortium includes three European TSOs, one of the most important European DSO group, several R&D companies and universities from 8 European Countries (among which the Italian RSE acting as project coordinator) and N-SIDE, the developer of the European market coupling platform EUPHEMIA.

Partners

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List of Abbreviations and Acronyms

Abbreviation/Acronym	Meaning
ACER	Agency for the Cooperation of Energy Regulators
ARERA	Autorità di Regolazione per Energia Reti e Ambiente (Italian Regulatory Authority for Electricity Gas and Water)
ASM	Active System Management
BESS	Battery Energy Storage Systems
BRP	Balance Responsible Party
CACM	Capacity Allocation and Congestion Management
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CBCA	Cross-border Cost Allocation
CDSO	Closed Distribution System Operator
CEC	Citizens' Energy Communities
CEDEC	The European Federation of Local Energy Companies
DE	Distributed Energy (scenario)
DER	Distributed Energy Resources
DSO	Distribution System Operator
DSR	Demand Side Response
EB GL	Electricity Balancing (Guideline)
EC	European Commission
ECG	Electricity Coordination Group
EDSO	European Distribution System Operators
EENS	Expected Energy Not Served
ENS	Energy Not-supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	Emission Trading System
EU	European Union
EV	Electric Vehicle
GA	Global Ambition (scenario)
GEODE	Groupement Européen des entreprises et Organismes de Distribution d' Energie
IEM	Internal Electricity Market
IGCC	International Grid Control Cooperation
IUS	System Benefit Index (Indice Utilità di Sistema)
KORRR	Key Organisational Requirements, Roles and Responsibilities
LCOE	Levelized Cost of Electricity
LOLE	Loss of Load Expectation
NECP	National Energy and Climate Plans

NRA	National Regulating Authority
NT	National Trends (scenario)
NTC	Net-transfer capacity
OPEX	Operational Expenditure
P2G	Power to Gas
PCI	Projects of Common Interest
PEM	Proton Exchange Membrane
PINT	Put IN one at the Time
R&D	Research and Development
R&I	Research and Innovation
REN	Redes Energeticas Nacionais
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SEW	Socio-economic Welfare
SGU	Significant Grid Users
SO	System Operator
SO GL	System Operation (Guideline)
SOEC	Solid Oxide Electrolyser Cell
SoS	Security of Supply
T&D	Transmission and Distribution
TN	Transmission Network
TOOT	The Take Out One at the Time
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VAN	Present Net Value (Valore Attuale Netto)
VOLL	Value of Lost Load

Executive Summary

This deliverable includes the first results of work package 6 ("Regulatory Analysis") of the FlexPlan project and is the first in a series of three reports that are looking into regulatory aspects concerning the methodologies developed within the project.

The present document carries out an assessment of the Pan-European regulatory framework aimed at ensuring that the project outcomes comply with the overall Pan-European political targets. This is complemented by reference to the existing practices at both TSO and DSO levels.

The activity applies qualitative evaluation methods, based on data collected through literature screening and survey-based research. The study restricts the focus to a pre-defined selection of issues, which have critical importance for FlexPlan project and are called "topics of interest". These topics represent either some key assumptions made within the project, or/and some attributes, which can be directly or indirectly decisive for the development and later for the implementation of the project outcomes. In addition to this the project team carried out a survey for DSOs and TSOs asking them about their practices related to the identified topics of interest for this study. Table 0.1 presents an overview of the identified topics of interest and reports some concluding comments for each of them.

Table 0.1 Summary of concluding comments to the identified topics of interest.

Category	Topic of interest	Conclusion
Flexible resources	Requirements for taking into consideration flexible resources in planning	One can conclude that there is a clear conviction emerging from the present regulatory framework and supported by a broad agreement across different stakeholders that flexible resources are a viable resource for the operation of the power system and thus should be considered in the planning procedures of the power grid. It is however difficult to see any common well-established practice in Europe, meaning that the process is still under development.
	Ownership and operation of energy storage	There is still an ongoing public discussion about involvement of system operators (SOs) into ownership, operation and management of energy storage facilities. The IEM Directive maintains position from the previous editions, which do not allow to own, develop, manage or operate energy storage facilities for SOs. It can also be noticed that

		the most recent version of recasts has been partially modified, in order to take into account input coming from some stakeholders, among others Eurelectric (see page 32 in [1]), expending the possible terms of derogation for SOs for operational purposes. Therefore, provision of flexibility from batteries will most likely be done as a service from independent operators in the close future. This also means that the system operators, which presently own electricity storage will have to transfer the ownership to third companies, unless they will get specific exception from their respective National Regulators. It seems it could be possible to own and operate batteries for some new actors as active customers and possibly Citizens Energy Communities (CECs). Apparently, the final solution could be shaped by a learning process connected to technologic maturing.
	Ownership and procurement of other resources including so-called strategic reserves	There is a strong message at European level that resources necessary for the operation of the system should be acquired via market-based arrangements. There are still many remaining questions about the organisation of such markets and on the best coordination schemes to be adopted for to regulate the interaction between TSOs and DSOs (for further details see results of H2020 project SmartNet [12]).
	Cross-border flexibility transfer	Involvement of flexibility resources in, for example, cross-border capacity transfer is not explicitly mentioned in the Regulation on IEM [5]. However, other sections of regulation put demand response and storage on equal terms with generation in dispatching and redispatching procedures. It is therefore reasonable to assume that the articles in EU's recent Directives and Regulations regulating cross-border participation mechanisms can be equally applied to flexibility services as well. There

		is also a clear signal from the European Commission about the need to facilitate the access to cross-border trade for the new suppliers, including suppliers of DR.
Organisation of Cost-Benefit Analysis (CBA)	Rules for allocation of costs and incomes between different TSOs and between TSOs and DSOs in new common investment projects	There is a clear message from the European Commission that socio-economic welfare should be taken as the main indicator for the prioritization of investments in new grid projects. From the Transmission side, following the requirements of the EU Regulation 347/2013 on guidelines for trans-European energy infrastructure [14] ENTSO-E has developed a Cost-benefit Analysis of Grid Development Projects, ensuring a common framework for multi-criteria CBA for TYNDP projects. This approach is also recommended as the standard guideline on project-specific CBA for the cross-border cost allocation (CBCA) process. The present practice is based on a split of costs at transmission system level. However, this practice may be reconsidered in case flexibility resources from distribution networks will be actively employed for the provision of system services to TSOs. DSOs point out that this may cause additional costs, which will have to be covered by the TSOs. For the present, there is no regulatory framework, applicable to this case.
	Evaluation criteria for distribution effects and consequences among different countries: monetary and non-monetary values	The ENTSO-E's guideline [6] presents a uniform procedure for the assessment of grid projects and is recommended to be used also for Cross-border costs allocation (CBCA). However, for different types of projects, different methods should be used, as there is no unified method yet available that could handle the special aspects of all these projects in a satisfying way.
	Multi-criteria vs. cost-based	Following the same conclusions as in the previous

	approach for evaluation of new projects	section, the practice at TSOs is mostly pre-determined by the CBA Guideline [2] from ENTSO-E. It is also important to repeat the point, made by ENTSO-E in its CBA guideline: costs mostly depend on scenario independent factors like routing, technology, material, etc., benefits are strongly correlated with scenario specific assumptions. As stated in the EC Guide to Cost-Benefit Analysis of Investment Projects, Economic appraisal tool for Cohesion Policy 2014-2020 (2014) [3] : "In contrast to CBA, which focuses on a unique criterion (the maximisation of socio-economic welfare), multi-criteria analysis is a tool for dealing with a set of different objectives that cannot be aggregated through shadow prices and welfare weights, as in standard CBA." This is why ENTSO-E favours (see 6.24 Section 24 in [2]) **a combined multi-criteria and cost benefit analysis** that is well adapted to the proposed governance and allows an evaluation based on the most robust indicators, including monetary values if an opposable and coherent unit value exists on a European-wide level. On DSOs side the practice seems to be more diversified, even though there is a preference for multi-criteria approaches.
	What cost function should be applied to reliability in order to include this into CBAs.	In general, the European Commission insists on using a CBA estimation in all decision-making processes concerning the power industry. This applies to several aspects like risk-preparedness, demand connection and network expansion planning etc. The key indicator for reliability is the lost load, which is monetised via the Value of Lost Load indicator (VOLL). There is a strong indication from ENTSO-E that there is no a uniform estimation for VOLL throughout Europe, and this could lead to

		less transparency and inconsistency and greatly increase uncertainties compared to using the physical units, as for example GWh/year in Expected Energy Not Supplied (EENS) indicator.
TSO-DSO interaction	Procedures for TSO-DSO interactions during planning: priority, iteration, sharing of information and models	The present situation is that TSOs bear the main responsibility for organizing the interaction with DSOs. There is also an indication that concrete actions and procedures will have to be defined bilaterally between TSO and DSO, where the Data Management report can be used as a common reference point. The "Key Organisational Requirements, Roles and Responsibilities" (KORR) [4] issued by ENTSO-E, naturally represents TSO-specific point of view, while it seems like opinion DSOs about the future evolution of roles and responsibilities is somewhat underrepresented at the moment.
	Sharing of resources between TSO and DSO: what are the priorities?	At present, there is no common regulatory or practice background allowing to draw clear conclusions on this topic. This necessity is clearly highlighted both at the institutional level and by the stakeholders.
	Responsibilities for congestion management and balancing	The overall evolution of roles and responsibilities depends upon the time horizon. In the first 10-20 years it is reasonable to suppose that TSOs will remain responsible for system balancing and congestion management in their own networks, while DSOs will have to deal with congestion in the distribution networks. It is also worth mentioning that the European Commission has started the formalisation process of several new business actors, including so-called Citizens Energy Communities (CEC) by indicating their roles and responsibilities in the IEM Directive [3]. Eurelectric looks at Microgrids and in particular CECs as an

		important future resource, which in the future can be endorsed with new duties, especially local balancing responsibility.
	Roles and responsibilities related to network expansion planning	The necessity of common TSO-DSO interaction in network planning process seems to be recognised by all parties. More specific details in the interaction are likely to be defined following implementation and maturing of the process.
	Technology maturity level, flexibility technologies	ENTSO-E's network code on demand connection opens for connection of loads, which support disconnection capabilities (automatic or remotely controlled), by defining specific technical requirements In TYNDP framework the scenarios include assumptions about cost development for different technologies and corresponding levelized cost of electricity. It is also necessary to mention that there is an on-going public consultation by the European Commission (open until 2020-05-14) related to development of new network codes, and code on demand side flexibility is mentioned as one of them. However, the drafting process might not start before 2022.
Other	Incentivisation mechanisms for flexibility resources	In general, the flexible resources can be an asset operated directly by the system operator or can be procured from external providers, as for example independent aggregators. From the regulatory point of view there is a protective measure, limiting the potential compensations for demand response providers, which is relevant to both categories. The method for calculating compensation may take account of the benefits brought about by the independent aggregators to other market participants and, where it does so, the aggregators or participating customers may be required to

		contribute to such compensation but only where and to the extent that the benefits to all suppliers, customers and their balance responsible parties do not exceed the direct costs incurred. Several national regulating provisions have already embedded incentive mechanisms for DSOs for investment into flexibility services. It is difficult to see any other specific incentives for the time being. There are however a lot of on-going sandboxes involving flexibility and they could result in a need for improving the present regulation.
	Criteria for development of scenarios time horizon and other details	The prevailing practice for TSOs is to use (fully or partially) the methodology of the TYNDP. The situation is somewhat more difficult for the DSOs, probably because they are directly interfaced with final users and local communities, so their plans will in many ways depend upon the development on the consumption side.
	Reliability criteria for system planning n-1 vs. probabilistic: different national practices, implementation timeline	TSO practice shows that n-1 is commonly used as a reliability criterion. The collected feedback about existing practice shows gradual implementation of probabilistic methodologies by some TSOs. Depending upon the overall success of the first implementations, this may result in common transfer to the probabilistic approach.

Summarising the screening process above and bearing in mind the overall picture, it seems evident that the European Commission strongly emphasises efficiency in different activities of the power system. Utilisation of the already existing resources as demand response can reduce the necessity for new investments. The Commission therefore demands consideration of the existing resources as a consistent part network expansion planning and considering demand response and storage with the same priority as generation in dispatching and redispatching procedures. Furthermore, the necessity to apply market-based mechanisms whenever possible is underlined in several regulatory documents with reference to many network operative aspects, as for example for the procurement of resources for ancillary services or even for system defence and restoration services. Finally, application of CBAs is put forward as a unified justification criterion to activate new investments. At the very same time it is necessary to mention that Commission shows a very pragmatic approach on several critical issues, as for example the above-mentioned issues related to ownership and operation of energy storage. The most recent recast of the IEM Directive shows modifications of the terms and introduction of new actors as CECs. Possibly, the final solution will emerge at the end of a learning process connected to technologic maturity

It is clear that the methodological efforts by ENTSO-E in developing network codes and guidelines have greatly contributed to a common understanding and approaches among the European TSOs. On some issues, however, there is a clear disagreement between TSOs and DSOs, like for example costs allocation. FlexPlan has probably to consider both points of view and make evaluations on a case-to-case basis.

The third version of ENTSO-E's CBA guideline describes the common principles and procedures for performing combined multi-criteria and cost-benefit analysis using network, market and interlinked modelling methodologies for developing Regional Investment Plans and the Union-wide TYNDP. The present practice at TSOs is mostly pre-determined by the Guidelines from ENTSO-E, even though there is a certain variation in application of it. It is also important to repeat the point, made by ENTSO-E in its CBA guideline: costs mostly depend on scenario independent factors like routing, technology, material, etc., benefits strongly correlate with scenario specific assumptions. On DSOs side the practice seems to be much less standardized, even with preference of multi-criteria approaches.

Another important issue is the assessment of the reliability indicator (VOLL). According to ENTSO-E's guideline the value for VOLL that is used during project assessment should reflect the real cost of outages for system users, hence providing an accurate basis for investment decisions. It is also stated that the experience has demonstrated that estimated values for VOLL vary significantly in dependency of geographic factors, differences in the nature of load composition, the type of affected consumers, and the level of dependency on electricity in the impacted geographical area, differences in reliability standards, the time of year and the duration of the outage.

Regarding the evolution of roles and responsibilities, in a 10-20 years' timeframe it is reasonable to suppose that TSOs will remain responsible for system balancing and congestion management in their respective networks, while DSOs will be allowed to deal with congestion in their own distribution network. It is also worth mentioning that the European Commission has started the formalisation process of several new business actors, including so-called Citizens Energy Communities. The introduction of these new actors could change the landscape and roles/procedures applied both in the planning and in the operation phases.

Finally, it must be remarked that there are strong regulatory signals prompting European system operators to consider flexible resources as a new important active subject in the grid expansion planning process for. Despite strong efforts from ENTSO-E to develop common methodologic principles, there are still several missing elements in the puzzle. This strengthens once again the importance and proper timing of FlexPlan project, both for testing new innovative grid planning methodologies coping with the present challenges, for the comprehensive scenario assessment up to 2050 and for the final synthesis of the results into regulatory guidelines brought to the attention of National Regulators and the Commission.

1 Introduction

The Pan-European regulatory landscape has been constantly changing during the recent years, focusing on the long-term goal of decarbonising the power sector. The growing share of Renewable Energy Sources (RES) as well as the appearance of new loads as a consequence of transports electrification and use of heat pump for space heating, create several challenges in Distribution and Transmission Networks, which require adequate compensating methods like congestion management and in some cases also the necessity to expand the network. The necessity to consider the usage of flexible resources as a support of grid planning, has been clearly highlighted in the most recent European Directives (e.g. internal market directive of the package "Clean Energy for All Europeans"). However, technically this still remains an "uncharted territory", and FlexPlan (2019-2022) is the first Horizon2020 project directly addressing this issue by proposing an innovative planning tool and validating it in large-scale realistic regional cases over Europe.

This deliverable is the first result of the FlexPlan work package dedicated to "Regulatory Analysis" and the first in a series of three reports that are looking into regulatory aspects related to the topics of the FlexPlan project, which include:

- Guideline for the compliance of FlexPlan network planning tool with EU overall strategies and regulatory conditions (present document)
- Identified regulatory limitations and opportunities, based on the regional cases (D6.2)
- Lessons and recommendations on Pan-European level regulation, policies and strategies (D6.3).

The present document carries out an assessment of the Pan-European regulatory framework aimed at ensuring that the project outcomes comply with the overall Pan-European political targets. This is complemented by reference to the existing practices at both TSO and DSO levels.

The purpose of the document therefore is to set an optimal environment for the real implementation of the planning tool realized by the FlexPlan project. This activity does not create specific visions nor draw a conclusive opinion, but rather defines the objective conditions for the project, based on regulatory acts, stakeholders' positions and practices.

2 Methodology

The activity applies qualitative evaluation methods, based on data collected through literature screening and survey-based research. The activity follows a stepwise approach, which is presented in Figure 2.1.

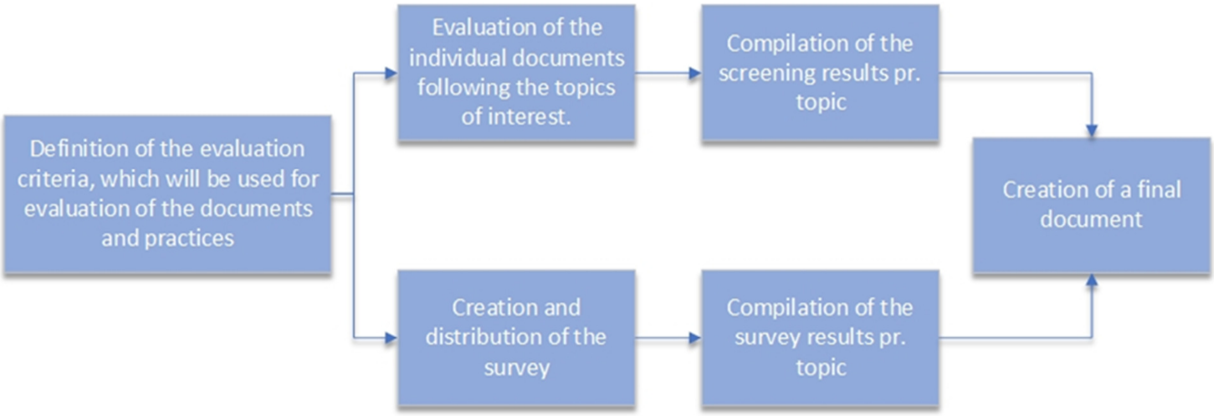

Figure 2.1 Steps in the working methodology

To facilitate this analysis, it was necessary to, first, decide which aspects of the project would be important and informative to evaluate against current practices or planned solutions outlined by various stakeholders. These are referred here as *topics of interest* and defined in the first step (see Section 2.2 for details). Based on this, the activity is divided into two parallel streams: one carries out a screening of a set of documents selected by the project group, while another builds up a survey aimed at being responded by TSOs and DSOs. Finally, the results of both activities are compiled into the present document.

2.1 Terms and defintions

The continuous changes in the regulatory landscape creates several new technical terms and definitions. Some of these have been already modified several times or in some cases vary from one official document to another. In order to reduce any potential ambiguity, this document has a specific Glossary section (see page 56), which refers to the most recent official European documents.

Flexibility is in many ways a key term in the study. Here, it is used as it is defined in "TSO-DSO Data Management Report"(see p.67 in [5]), stating that: "*Active management of an asset that can impact system balance or grid power flows on a short-term basis (from day-ahead to real time). Flexibility can be provided by different assets. The first three can be both directly or through an aggregator:*

- *generation (part of the dispatchable units, RES)*
- *load facilities (involved in a demand response programme)*
- *storage (pumped storage power station, batteries, etc.); and/or*
- *interconnectors (intraday energy exchanges).*

Flexibility can be used by:

- *the TSO for balancing and congestion management in the short term and planning in long-term contracting*
- *the DSO for congestion management in the short term and planning in long-term contracting and/or*
- *the BRP for portfolio management both in the short and long term (investment)"*

Furthermore, within the FlexPlan project a set those flexible resources has been defined (see Table 2.1), which are considered to be in the scope of the project.

Table 2.1 Overview of the flexible resources. Source: [6]

Flexibility resource	
Battery energy storage system	
Demand Response	Domestic
	Industrial
Electric vehicles	
Hydrogen	Alkaline
	PEM
	SOEC
Pumped hydro	
Thermal loads	Space heating /cooling
	Cold storage
Combined heat and power	
Compressed air storage	
Liquid-Air Electricity Storage systems	
Thermo electric storages	

Capacitor banks, shunt reactors and phase-shifters are conventional assets which can be considered as enablers for flexibility but are not flexibility resources.

2.2 Topics of interest defined for the study

In order to create more systematic approach, a set of *topics of interest* has been identified. These topics represent either some key assumptions made within the project, or/and some attributes, which can be directly or indirectly decisive for development of and later implementation of the project's outcomes. The topics were identified in a common effort of the whole project (see Figure 2.2) and were divided into four subcategories.

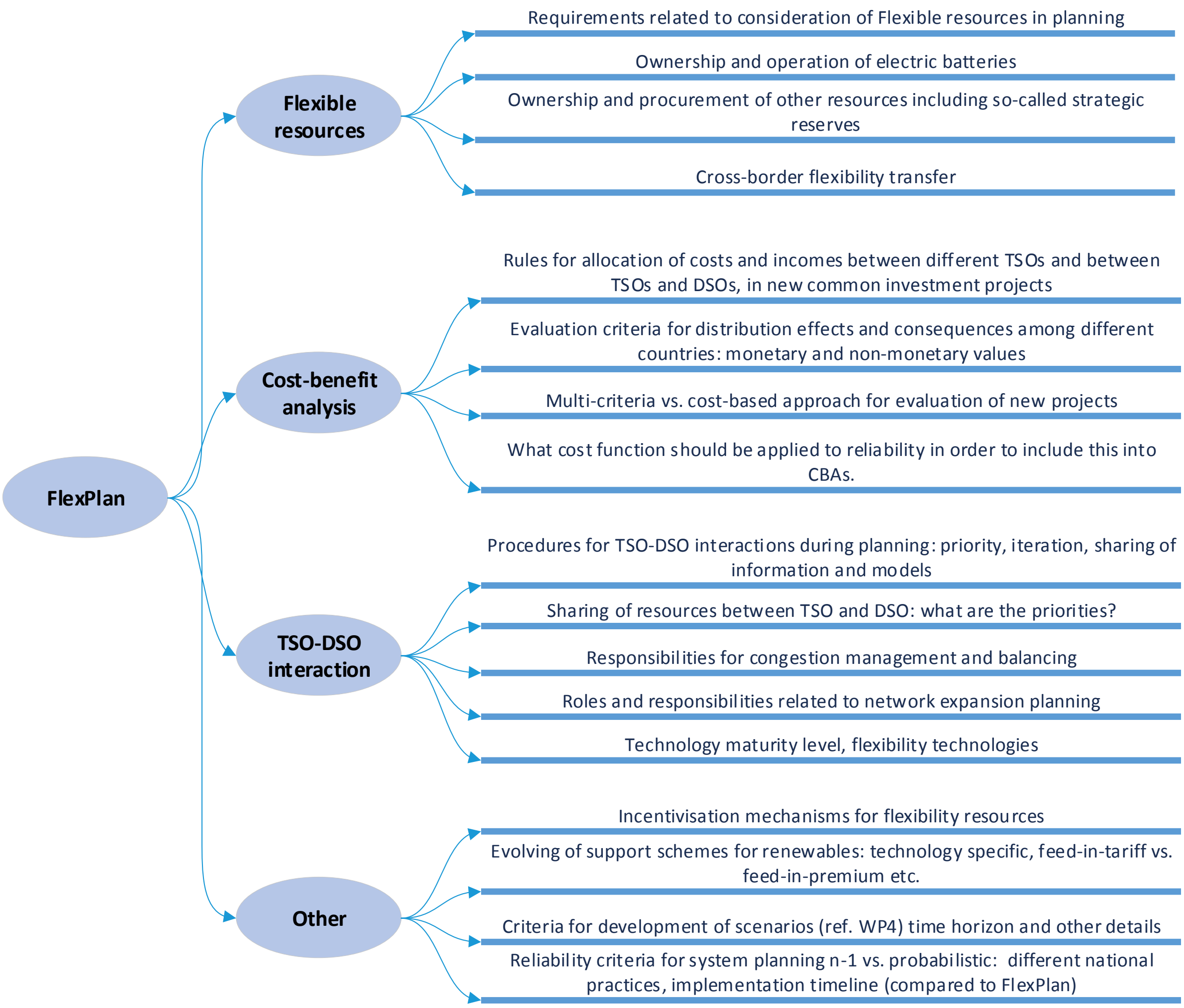

Figure 2.2 Topics of interest, which were identified

2.3 Survey of the present practices

The project team initiated a survey for DSOs and TSOs asking them about their practices related to the identified topics of interest for this study. Considering differences among DSOs and TSOs, the survey was developed in two versions. Responses were received from three TSOs (directly involved into the project) and four DSOs, of which only one participates in the project while the three remaining DSOs joined the survey through the EDSO network (Table 2.2).

Table 2.2 Overview over respondents to FlexPlan survey

TSOs	REN - Rede Eléctrica Nacional, S.A. (PT)
	TERNA (IT)
	ELES Ltd (SI)
DSOs	e-distribuzione S.p.A (IT)
	i-DE Redes Inteligentes, Grupo Iberdrola (ES)

	Netz Niederoesterreich (AT)
	Energijos skirstymo operatorius, AB (LT)

As already clarified, the results of the survey are complementary to those obtained from the screening study.

2.4 Selection of documents for the screening

Selection of the documents is determined by the previously defined purpose of the study. The documents considered in this study have been issued by several types of stakeholders, including:

- Governmental Organisations – the Europeans Commission (EC), issuing Directives and Regulations, including Network Codes/Guidelines
- Organisations working on different aspects of Regulation e.g. the European Commission, ACER and ENTSO-E, which is responsible for development of Network Codes/Guidelines, standard methods for cost-benefit analysis
- Interest organisations and Industrial Associations as Eurelectric, EDSO, GEODE and CEDEC

2.5 Limitations of the study

Narrowing the scope: The present study in general focuses on rules, procedures and practices related to planning activities. Therefore, in some cases the magnitude of the available issues and topics have been scoped down, according to their relevance to the study's main objectives. This was for example done in the area of roles and responsibilities, where TSOs and DSOs as key actors in any national power system have virtually hundreds of responsibilities defined in different documents, making it impossible to mention due to limitations of time and space. Therefore, only those responsibilities which are directly related to the planning activities are mentioned.

Evolving regulatory landscape: Several key regulatory documents from the recent regulatory package "Clean Energy for all Europeans", including The Directive (2019/944) [7] on common rules for the internal market for electricity and the corresponding Regulation (2019/943) [8], have been amended several times, resulting in several recasts. Some of the formulations have had a significant transformation, and some new terms have introduced. The study refers to the most recent recast, existing at the time of writing. Describing important issues, in addition to regular references the study also mentions specific sections or chapter in the referred documents, so the information can be checked for further details, if needed.

Common terminology: Following the previous point, several new terms have developed and modified. In some cases, it has been noticed that certain terms may be used in somewhat ambiguous manner depending upon the specific context and application. Agreeing upon common terminology for the concepts was even defined as a first objective in the common TSO-DSO report [5]. In order to avoid any potential misinterpretations, the document includes a glossary (see page 56) of the key terms, which are used. The glossary uses official documents e.g. EC's Directives and Regulations as source.

3 The screening study

The chapter is organized in the following sections:

- **Step 1:** Overview of the present or/and proposed (not fully implemented yet) legislative acts and definitions using the European Directives, Regulations, including Network Codes/Guidelines etc. as sources.
- **Step 2:** Summary of the stakeholders' opinions have been mapped by using position papers and similar as sources
- **Step 3:** Reference to the present situation (i.e. status quo), which refers to the existing practices at the surveyed TSOs and DSOs
- **Step 4**: Discussion

Several topics are somewhat interrelated, therefore some of the points can be mentioned repeatedly in the description.

3.1 Flexible resources

3.1.1 Requirements related to consideration of flexible resources in planning

The EC Directive (EU) 2019/944 on common rules for the internal market for electricity [7] opens with the statement that DSOs should be incentivised for using distributed resources in order to avoid network expansions. The development of a distribution system shall be based on a transparent network development plan that distribution system operators shall submit every two years to the regulatory authority.

The Directive has a specific section (art.32) dedicated to incentives for use of flexibility in distribution networks, which states that the distribution network development plan shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion.

Furthermore, the same document (art.51) defines that when elaborating the ten-year network development plan, the transmission system operator shall fully take into account the potential for the use of demand response, energy storage facilities or other resources as alternatives to system expansion.

The EC Regulation 2019/943 on the internal market for electricity (see (7) in [8]), which is linked to the above mention Directive, states that in order to integrate the growing share of renewable energy, the future electricity system should make use of all available sources of flexibility, particularly demand side solutions and energy storage, and should make use of digitalisation through the integration of innovative technologies with the electricity system. The document puts on equal terms redispatching rules for generation and demand response. It shall be open to all generation technologies, all energy storage and all demand response, including those located in other Member States unless technically not feasible.

In the Regulation (EU) 2019/941 on risk-preparedness in the electricity sector [9] the flexibility is not directly mentioned, the document however points out that demand-side measures are an important part of the coordinated actions in creation of national risk preparedness plans.

In ENTSO-E's 3rd Guideline for CBA of Grid Development Projects [2] flexibility of demand is considered as a part of estimation of socio-economic welfare.

When it comes to position of TSOs and DSO, the common document known-as "Active System Management Report" (ASM) [10] mentions (see pages 16 and 28) that planning of the grid reinforcement in different time scales (years-months ahead): flexibility services (both implicit and explicit) can be used as a complement for dealing with the congestion. Timely grid expansion, should be applied when affordable and when providing a better business case than market-based flexibility, should be regarded as a basis.

In another common document "TSO-DSO Data Management Report" [5] a specific use case "Network Planning" is presented, comprising both long-term network development (from one year ahead onwards) and operational planning (from hour ahead to year ahead). The document does not put forward specific flexibility requirements for planning. However, it points out the importance of flexibility as a resource for congestion management and system balancing. The document states that flexibility can be used for different purposes, so a coordination process is needed to ensure that flexibility bids can be activated only once and will not cause problems in neither the grid they are connected to nor in grids that might be influenced (see page 20). It is essential that TSOs and DSOs agree on mutual processes and data exchanges. It is key that flexibility be allocated optimally and in the most efficient way (social welfare maximisation, security of supply).

In the document "European Power System 2040: Completing the map" [11] it is unclear whether flexibility was included into the study or not. the document mentions that demand-side responses as well as electric vehicles have been considered in the modelling without specification of any other details.

The document "The Value of the Grid: Why Europe's distribution grids matter in decarbonising the power system" [12], developed by EDSO, refers directly to ASM report [10] and agrees that flexibility services will provide DSOs with additional tools to better cope with congestion and manage their network at reasonable cost. From a long-term perspective, the use of flexibility services will rightly compete with traditional investment options for grid reinforcement or upgrades. Therefore, in the future, DSOs will need to adapt their development plans and include available sources of flexibility among others as an alternative to standard network investments.

Present practices

Several responding TSOs mentioned that they operate Capacitor banks, shunt reactors and phase-shifters. This however can be considered as conventional type of assets and not flexible devices (See Section 2.1 for explanation) and not as flexible resources.

REN addresses "Demand Response" as a flexibility solution. However, this sentence is just to indicate that up to now, the maturity of relevant technologies and their application to the Portuguese network does not yet justify any specific methodology to be applied to grid planning including these solutions. The only exception to this is the undergoing pilot project, created by the Portuguese Regulator, in which demand facilities with a capacity higher than 1MW can participate in the balancing markets.

Discussion

One can conclude there is a clear conviction emerging from the present regulatory framework and supported by a broad agreement across different stakeholders that flexible resources are a viable resource for the operation of the power system and thus should be considered in the planning procedures of the power grid. It is however difficult to see any common well-established practice in Europe, meaning that the process is still under development.

3.1.2 Ownership and operation of energy storage

The IEM Directive (art.1 in [7]) underlines importance of the energy storage by defining the regulatory conditions for it on equal terms with generation, transmission and distribution. Two specific sections (art.36 and art.54) in the most recent version of IEM Directive present the official position of the European Commission regarding ownership of energy storage facilities by respectively Distribution and Transmission System operators. The document maintains position from the previous editions of the Directive, which do not allow to own, develop, manage or operate energy storage facilities for System Operators (SOs). The Directive refers to several reasons for this position, including avoidance of cross-subsidising between the energy storage and regulated functions, distortion of competition and securing free access to the storage services to all market participants (see (62) in [7]).

However, by way of derogation from it, the Member States may allow SOs to own, develop, manage or operate energy storage facilities, where they are fully integrated network components and the regulatory authority has granted its approval, or where all of the following conditions are fulfilled [7] (almost similar conditions for TSOs and DSOs):

a) other parties, following an open, transparent and non-discriminatory tendering procedure that is subject to review and approval by the regulatory authority, have not been awarded a right to own, develop, manage or operate such facilities, or could not deliver those services at a reasonable cost and in a timely manner;
b) such facilities (or non-frequency ancillary services for TSOs) are necessary for the system operators to fulfil their obligations under this Directive for the efficient, reliable and secure operation of the system and they are not used to buy or sell electricity in the electricity markets; and

c) the regulatory authority has assessed the necessity of such a derogation, has carried out an ex ante review of the applicability of a tendering procedure, including the conditions of the tendering procedure, and has granted its approval.

Active customers (see the Glossary, page 56) are allowed to own energy storage facilities (art.15 in [7]) and have several rights stipulated in the document, related to grid connection, not subject to additional fees and charges. In addition to this, it is also interesting to mention that so-called Citizen Energy Community (CEC) may engage in energy storage services or charging services for electric vehicles or provide other energy services to its members or shareholders(see (11) in [7]).

The document [2] does not explicitly mention anything about the ownership of the batteries, it says however that storage projects are, in principle, assessed in a similar way as transmission projects.

Present practices in ownership and operation of batteries

One of the responding TSOs (ELES) has indicated that as a part of two specific projects, the company procures battery energy storage systems (BESS) with size of 10 MW/50MWh and 4 MW/8MWh. One of DSOs (Netz Niederoesterreich) has also indicated ownership of BESS with 2 MW capacity.

Discussion

Taking any specific position towards this important issue is not among objectives of the present project. There is still an ongoing public discussion about involvement of system operators into ownership, operation and management of energy storage facilities. The document maintains position from the previous editions of the Directive, which do not allow to own, develop, manage or operate energy storage facilities for System Operators (SOs). It has been also noticed the most recent recasts of the IEM Directive have been partially modified, according to input from some stakeholders, among which Eurelectric (see page 32 in [1]), specifying the possible terms of derogation for System Operators for operational purposes (mostly full integration as network components and necessity for secure and reliable operation). There is, apparently, an on-going learning process connected to technologic maturity, which is gradually shaping the final terms. Therefore, provision of flexibility from batteries will most likely be conceived as a service from independent operators in the close future. This also means that the system operators, which presently own electricity storage will have to transfer the ownership to third companies, unless they will get specific exception from their respective National Regulators according to the above-mentioned conditions. It seems to be possible to own and operate the batteries for the new actors as active customers and probably CECs.

3.1.3 Ownership and procurement of other resources including so-called strategic reserves

The IEM Directive defines (see art.31 in [7]) that for DSOs procurement of the products and services referred to operation of the system shall ensure the effective participation of all qualified market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation.

For TSOs specifically procurement of balancing capacity shall be market-based and organised in such a way as to be non-discriminatory between market participants in the prequalification process (see art.6 in [8]). Cost-efficient and market-based procurement of balancing and ancillary services shall be ensured by the member states. When it comes to Risk-preparedness regulation (see (31) in [9]), measures taken to prevent or mitigate electricity crisis should be first market-based and non-market (see Glossary on page 56) shall be only the last resort if all options provided by the market have been exhausted or insufficient.

In common Active System Management report TSOs and DSOs commonly suggest a market-based approach for procurement of resources for congestion management [10]. Another common TSO-DSO document "General Guideline for reinforcing cooperation between TSOs and DSOs" (see page 2 in [13]) defines the main principle for procurement of resources, necessary for TSOs and DSOs. Coordinated access to resources is mentioned as a main principle:

- The use of resources for TSO and DSO purposes needs to be better coordinated.
- When decisions are made on the TSO side, the side effects on the DSO side (and vice versa) need to be taken into consideration to avoid a lack of resources for alternative purposes or in induced grid issues on another network.

In addition, it is mentioned that in order to enable flexibility (see page 5 in [13]) it is important to determine how flexibility is measured. For this, a baseline calculation method might be developed. DSOs and TSOs could investigate possible options for coordinating the use of flexible resources. Among these options are:

- Single marketplace: full integration of bids for balancing and congestion management. Possible solution: marked bids/DSO or TSO tag when geographical information is included.
- Local congestion markets: these would feature a local market for congestion management operating with a high level of coordination between TSOs and DSOs and in coherence with existing markets.

Present practices in ownership and procurement of other resources

Among the TSOs, one company (REN) procures 2 437 GW for balancing purposes, the second TSO (TERNA) procures aggregated resources from of consumption, production and storage units from 1 MW without specific limit on maximum capacity. They are used for congestion management, balancing and tertiary reserve. The third TSO (ELES) procures a part of tertiary reserves from DSM in range 69 MW and secondary reserves from BESS with current capacity of 14 MW.

On the DSO side, only one company indicated procurement of flexible resources as interruptible heat pumps and water boilers.

Discussion

There is a strong message at European level that resources necessary for the operation of the system should be acquired via market-based arrangements. There are still many remaining questions about the organisation of such markets and on the best coordination schemes to be adopted for to regulate the interaction between TSOs and DSOs (for further details see results of H2020 project SmartNet [12]).

3.1.4 Cross-border flexibility transfer

In general, involvement of flexibility resources in, for example, cross-border capacity transfer is not explicitly mentioned in the Regulation on IEM [8]. However, other sections of regulation put demand response and storage on equal terms with generation in dispatching and redispatching procedures. It is therefore reasonable to assume that the articles in EU's recent Directives and Regulations regulating cross-border participation mechanisms can be equally applied to flexibility services as well. The IEM Directive (see 13 in [7]) points out that the Member states should facilitate cross-border access for new suppliers including suppliers of demand response (DR).

Capacity mechanisms other than strategic reserves and where technically feasible, strategic reserves shall be open to direct cross-border participation of capacity providers located in another Member State. Transmission system operators should facilitate the cross-border non-discriminatory participation of interested producers in capacity mechanisms in other Member States. Calculation of cross-zonal capacities should be done by regional coordination centres (see Annex I in [8]).

ENTSO-E in its guideline [2] mentions cross-border exchange of balancing capacity as flexibility service, but does not yet put forward a specific methodology to be applied to arrive at quantitative/monetised results.

Another document (see page 30 in [5]) states that the potential for balancing resources to be effectively shared between countries can enhance the security of supply and reduce overall system costs, so there is a strong rationale to further develop cross-border capacities and balancing markets in Europe.

The study [11] argues the necessity of interconnections mostly from the market point of view i.e. high price differences of national borders. In addition, it refers to cross-border and internal physical bottlenecks as a part of 2040 analysis, concluding that both it is necessary to have both cross-border and internal network reinforcement.

Present practices of cross-border flexibility transfer

One of the TSOs (ELES) is involved in several projects, dealing with reserve sharing and now being implemented in projects MARI in PICASSSO. Terna also participates in the European projects for the exchange of balancing energy between TSOs pursuant to Regulation (EU) 2017/2195 TERRE for the exchange of balancing energy from replacement reserves, MARI for the exchange of balancing energy from frequency restoration reserves with manual activation, PICASSO for the exchange of balancing energy from frequency restoration reserves with automatic activation and the International Grid Control Cooperation (IGCC) for imbalance netting process. None of DSOs has been involved into similar projects.

Discussion

Involvement of flexibility resources in, for example, cross-border capacity transfer is not explicitly mentioned in the Regulation on IEM [5]. However, other sections of regulation put demand response and storage on equal terms with generation in dispatching and redispatching procedures. It is therefore reasonable to assume that the articles in EU's recent Directives and Regulations regulating cross-border participation mechanisms can be equally applied to flexibility services as well. There is also a clear signal from the European Commission about the need to facilitate the access to cross-border trade for the new suppliers, including suppliers of DR.

3.2 Organisation of Cost-Benefit Analysis (CBA)

Considering the importance of the topic for the FlexPlan project, this introduction provides a very brief overview to Cost Benefit Analysis (CBA) of Grid Development Projects guideline according to the 3rd version [2], which was developed in compliance with the requirements of the EU Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure [14].

The 3rd CBA guideline describes the common principles and procedures for performing combined multi-criteria and cost-benefit analysis using network, market and interlinked modelling methodologies for developing Regional Investment Plans and the Union-wide TYNDP.

In general, the assessment of projects takes into account the range of future energy scenarios; a definition of the reference network used to assess the impact of the reinforcement; and the acceptable techniques to be used in undertaking the analysis. Whilst projects' costs mostly depend on scenario independent factors like routing, technology, material, etc., benefits strongly correlate with scenario specific assumptions. Therefore, scenarios which define potential future developments of the energy system are used to gain an insight in the future benefits of transmission projects.

The **scenarios** reflect European and national legislations in force at the time of the analysis and consider plausible energy futures characterised by, amongst others, generation portfolios, demand forecasts and exchange patterns with the systems outside the study region etc.

For different types of projects, different methods should be used, as there is no unified method yet available that could handle the special aspects of all these projects in a satisfying way. Therefore, three options are given to calculate the:

- **Market simulations**
  Market studies are used to calculate the cost optimal dispatch of generation units under the constraint that the demand for electricity is fulfilled (taking into account DSR) in each bidding area and in every modelled time step. There are different options to represent the transmission network in market models, namely:
- **Net transfer capacity (NTC)-based market simulations**
    - Flow-based simulations

- Network simulation

  Network studies represent the transmission network in a high level of detail and are used to calculate the actual load flows that take place in the network under given generation/load/market exchange conditions.

- **Combined market and network simulations i.e. redispatch simulations**

  Redispatch simulations is a combination of both network and market studies by combining network contingencies with the economy of the generation dispatch.

The next step is definition of the **reference grid** that is made up of the existing grid and the projects that have a strong chance of being implemented by the date of the scenarios that are considered. It is used as the starting point of the CBA.

Project benefits are then calculated as the difference between simulations including the project and simulations exclude the project. Market and network simulations with projects either added to the reference grid, or removed from it, are compared to the simulations of the reference grid alone to assess each of the projects' performance. Consequently, the reference case has a significant impact on the outcome of an individual project assessment.

Two methods for project assessment are described as follows:

- **Take Out One at the Time (TOOT)** method, where the reference case reflects a future target grid situation in which all additional network capacity is presumed to be realised (compared to the starting situation) and projects under assessment are removed from the forecasted network structure (one at a time) to evaluate the changes to the load flow and other indicators.
- **Put IN one at the Time (PINT)** method, where the reference case reflects an initial state of the grid without the projects under assessment, and projects under assessment are added to this reference case (one at a time) to evaluate the changes to the load flow and other indicators.

Sensitivity analysis can be performed with the intention of observing how certain changes of scenario (e.g. by changing only one parameter or a set of interlinked parameters) affects the model results in order to achieve a deeper understanding of the system's behaviour regarding these parameters.

Based on the experience of previous TYNDPs the parameters listed below could be optionally be used to perform sensitivity studies.

- Fuel and CO2-Price
- Long-term societal cost of CO2 emissions
- Climate year
- Load
- Technology phase-out
- Must-run
- RES installed capacity

The **assessment of costs and benefits** are undertaken using combined cost-benefit and multi-criteria approach within which both qualitative assessments and quantified, monetised assessments are included.

Using this combined cost-benefit and multi-criteria assessment each project is characterised by its impact of both the added value for society and in terms of costs in a standardised way.

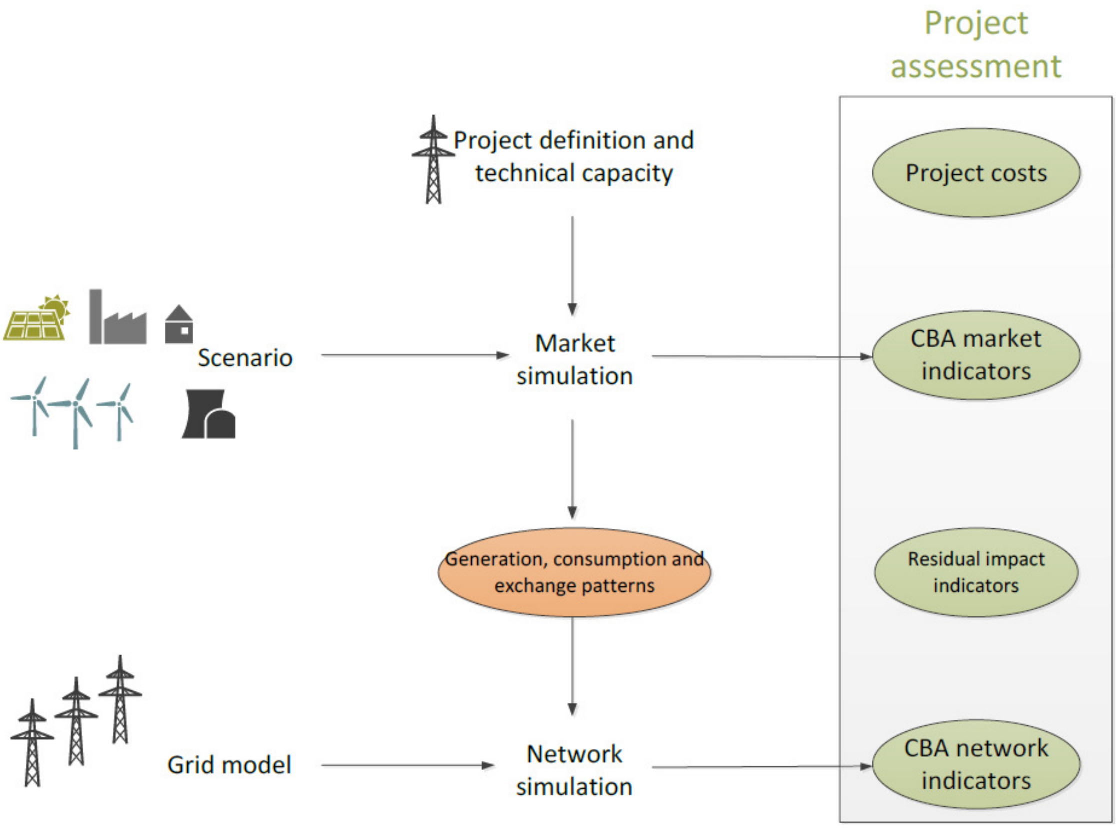

Figure 3.1 The project assessment process. Source: [2]

Figure 3.1 presents a simplified description of the project assesssment process. "CBA market indicators" and "CBA network indicators" are the results of market and network studies respectivley, "Project costs" and "Residual impacts" are obtained without use of simulations.

The main categories of the prodject assessment process are presented in Figure 3.2.

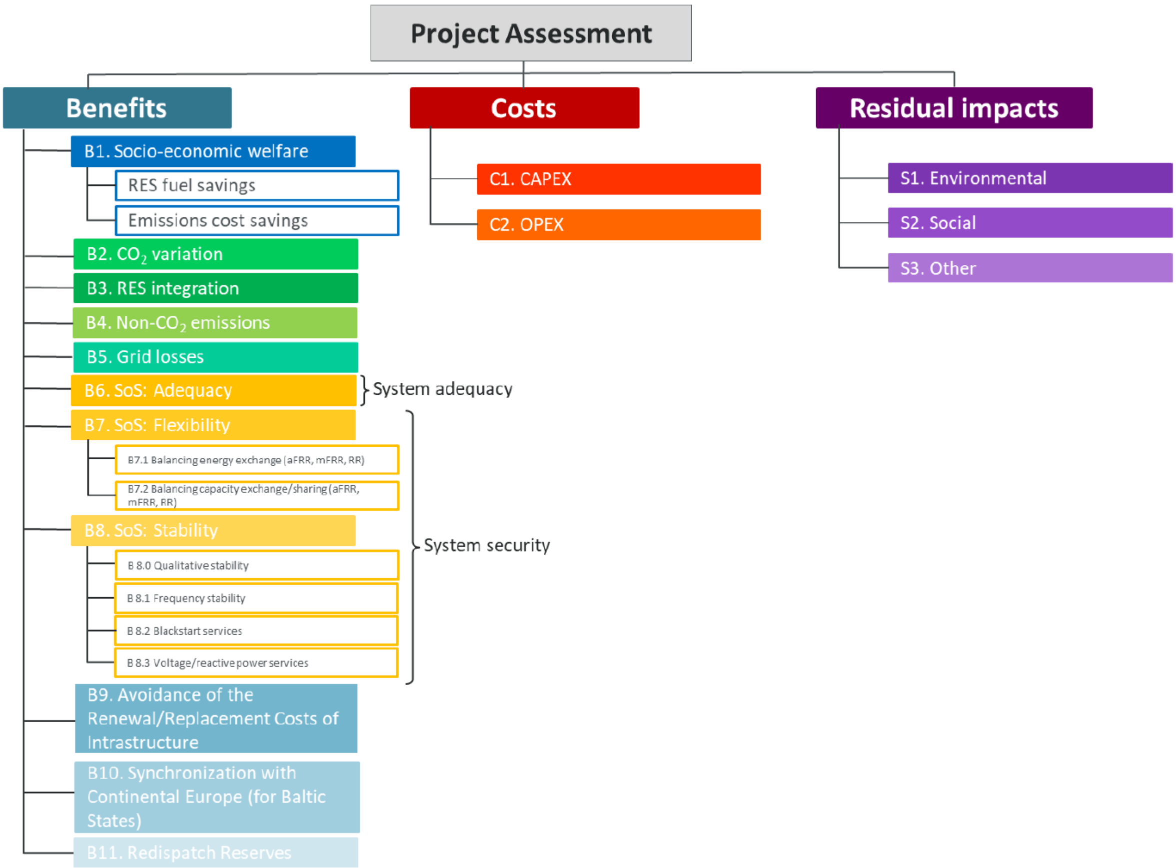

Figure 3.2 Main categories of the project assessment methodology. Source: [2]

Brief overview and descriptions of the all listed benefits, costs and residual impacts are presented in Annex II (see page 60). More detailed explanations and methodology for estimation can be found in [2]. In addition to this, Annex III (see page 63) presents a brief overview over CBA Methodology, practiced by the Italian TSO TERNA.

The project assessment has to be carried out based on the eleven benefit indicators mentioned above, as well as the three residual impact indicators and the investment costs. Whilst the benefits should be given for each study scenario (e.g. the TYNDP visions), costs and residual impacts are scenario-independent indicators.

3.2.1 Rules for allocation of costs and incomes between different TSOs and between TSOs and DSOs in new common investment projects

The 3rd ENTSO-E's guideline for Cost Benefit Analysis of Grid Development Projects [2] is in general recommended to be used for Cross-border costs allocation (CBCA). However, it is mentioned that project appraisal is based on analyses of the global (European) increase of welfare. This means that the goal is to bring up the projects which are the best for the European power system. Some benefits (socio-economic welfare, CO2…) may also be disaggregated on a smaller geographical scale, like a member state or a TSO area. This is mainly useful in the perspective of cost allocation and should be calculated on a case-by-case basis, taking into account the larger variability of results across scenarios when calculating benefits related to smaller areas.

The common TSO-DSO report [5] presents separately views of TSOs and DSOs:

- **DSO view:** The DSO duty to expand the network has to be weighed against any (new) right to limit network usage. In order to maximise social welfare (e.g. by minimising overall system costs) a proper assessment is needed.
- **DSO view:** Balancing services based on assets connected on the DSO level should, for economic reasons, not lead to any additional constraints in DSO networks. If this is the case, TSO and the market actor interested in using this asset connected to the DSO network on the balancing market should cover the full costs of any grid enforcement according to the national regulations on the allocation of network expansion costs.
- TSO view: In case of additional constraints in DSO's networks, a regulatory framework should be established in which the compromise between the additional value of the flexibility not available to the balancing markets due to these constraints and the network expansion that resolves those congestions is evaluated and, in any case, ensures a proper allocation of the corresponding additional costs.

Present practices for rules for allocation of costs and incomes

One of the TSOs (ELES) has responded that common projects with DSOs and other TSOs apply specific bilateral agreements in scope of the Slovenian legislation for allocation of costs and incomes.

From DSOs' several alternative practices were mentioned:

- Cost allocation is between TSO and DSO: TSO transmission feeders and DSO transformers and distribution feeders (Iberdrola).
- Mainly at the interchange substation with the TSO there are common investment projects. Costs and earnings are split by the system border of the voltage levels (Netz Niederoesterreich).
- Each project is unique and coordinated between DSO and TSO individually (Energijos skirstymo operatorius).

Discussion

There is a clear message from the European Commission that socio-economic welfare should be taken as the main indicator for the prioritization of investments in new grid projects. From the Transmission side, following the requirements of the EU Regulation 347/2013 on guidelines for trans-European energy infrastructure [14] ENTSO-E has developed a Cost-benefit Analysis of Grid Development Projects, ensuring a common framework for multi-criteria CBA for TYNDP projects. This approach is also recommended as the standard guideline on project-specific CBA for the cross-border cost allocation (CBCA) process.

The present practice is based on a split of costs at transmission system level. However, this practice may be reconsidered in case flexibility resources from distribution networks will be actively employed for the provision of system services to TSOs. DSOs point out that this may cause additional costs, which will have to be covered by the TSOs. For the present, there is no regulatory framework, applicable to this case.

3.2.2 Evaluation criteria for distribution effects and consequences among different countries: monetary and non-monetary values

The Regulation on risk-preparedness defines that coordinated cross-country measures for assistance in case of electricity crisis should take account of social and economic factors, including the security of Union citizens and proportionality (see (26) [9]).

The 3rd ENTSO-E's Guideline (see Section 6.3 in [2]) suggests a set of evaluation criteria for project assessment methodology, including monetised and not-monetised.

The main cost categories are presented in Figure 3.2 and explanation of these is included into Annex (see page 60) for more detailed description and monetisation level see [2]. The guideline also specifically mentions for cross-border projects, that for different types of projects, different methods should be used, as there is no unified method yet available that could handle the special aspects of all these projects in a satisfying way.

Therefore, three options are given to calculate the benefits:

- market simulations
- network simulations
- combined market and network simulations, i.e. redispatch simulations.

Present practices for evaluation criteria for distribution effects and consequences among different countries

In the Italian CBA, the main evaluation criteria are market integration, security of supply (SoS), RES integration, ASM costs reduction, resiliency increasing, GHG emissions reduction. All the impacts are monetized. The criteria for evaluation of new investment project are always monetized in the Italian CBA. According to TERNA, for all projects included in the NDP, these criteria are used for the evaluation of the projects' benefits. For cross-border projects included in TYNDP, the benefits evaluation follows the ENTSO-E's CBA guidelines (possibly integrated with the assessments made at national level). For the latter, the assessment of the cost allocation can follow specific bilateral agreements between the two TSOs or alternatively the rules of the CBCA.

In Slovenia no special rules are applied, and distribution is done according to bilateral agreements. In future, distribution of cost might follow rules for Cross Border Cost Allocation as set in ACER's recommendation and taking ENTSO-E's TYNDP project evaluation results.

Discussion

The ENTSO-E's guideline [6] presents a uniform procedure for the assessment of grid projects and is recommended to be used also for Cross-border costs allocation (CBCA). However, for different types of projects, different methods should be used, as there is no unified method yet available that could handle the special aspects of all these projects in a satisfying way.

3.2.3 Multi-criteria vs. cost-based approach for evaluation of new projects

The ENTSO-E's guideline (see Section 3 in [2]) suggest combined cost-benefit and multi-criteria analysis, defining the main principles for the assessments.

Following the multi-criteria approach, the national risk preparedness plans [9] should take into account the environmental impacts of demand-side and supply-side measures proposed.

The EU Power System 2040 study [11] does not actually assess projects as such, but considers reinforcement of the network for future (2040) scenarios, comparing with potential costs:

- Fragmented markets (high price differences on borders)
- Generation capacity i.e. reliability of supply
- Meeting CO2 targets i.e. curtailment of RES
- Handling physical flows i.e. cross-border and internal bottlenecks
- Frequency management including system inertia
- Transient and voltage stability

Considering the view of DSOs, their common Declaration document [15] refers to the rate of return as the main indicator for evaluation of new project.

Present practices for evaluation of new projects

TSOs in Italia and Portugal apply multi-criteria approach, while in Slovenia during planning process different technical solutions may appear. They are evaluated not only by technical means (N-1, overloads, ENS, ...) but also by nontechnical means, such as cost of construction, environmental impact, probability of possible delays due to siting procedures etc. More specifically, REN evaluates new projects using a multi-criteria approach considering safety of supply; modernization and grid reliability, quality of service, operational efficiency, sustainability, promotion of competition to ensure market rules, and other technical criteria for infrastructure.

On the DSOs' side ENEL and Iberdrola apply multi-criteria approach. In case of Netz Niederoesterreich this is organised via Innovation Management, which sets a radar on technology. From that a company strategy is derived. Project proposals within this strategy are assessed according to the investment budget. All other new projects are part of the standard investment (refurbishment) program, which planning is done in a year ahead cycle of the management.

Discussion

Following the same conclusions as in the previous section, the practice at TSOs is mostly pre-determined by the Guidelines from ENTSO-E.

It is also important to repeat the point, made by ENTSO-E in its CBA guideline [2]: costs mostly depend on scenario independent factors like routing, technology, material, etc., benefits are strongly correlated with scenario specific assumptions. As stated in the EC Guide to Cost-Benefit Analysis of Investment Projects, Economic appraisal tool for Cohesion Policy 2014-2020 (2014) [3] : "In contrast to CBA, which focuses on a unique criterion (the maximisation of socio-economic welfare), multi-criteria analysis is a tool for dealing with a set of different objectives that cannot be aggregated through shadow prices and welfare weights, as in standard CBA." This is why ENTSO-E favours (see 6.24 Section 24 in [2]) **a combined multi-criteria and cost benefit analysis** that is well adapted to the proposed governance and allows an evaluation based on the most robust indicators, including monetary values if an opposable and coherent unit value exists on a European-wide level.

On DSOs side the practice seems to be more diversified, even though there is a preference for multi-criteria approaches.

3.2.4 What cost function should be applied to reliability in order to include this into CBAs.

This section was initially planned to focus on CBAs explicitly related to planning of network expansion. Since the power grid is a very complex system with several interrelated factors and similarities, some of other types of CBAs may be relevant and useful for FlexPlan project. This is in particularly related to the mentioned below CBA requirements for connection of new facilities, described in the corresponding Network Code [16].

The Regulation on IEM (see art.11 in [8]) demands that by 5 July 2020 for the purpose of setting a reliability standard, regulating authorities shall determine a single estimate of the value of lost load (VOLL) for their territory. That estimate shall be made publicly available. Regulatory authorities or other designated competent authorities may determine different estimates per bidding zone if they have more than one bidding zone in their territory. The reliability standard shall be calculated using at least the value of lost load and the cost of new entry over a given timeframe and shall be expressed as 'expected energy not served' and 'loss of load expectation'. By 5 January 2020 ENTSO-E should submit to ACER a draft methodology for calculating (the project group is not aware if the draft has been submitted):

- the value of lost load (VOLL)
- the cost of new entry for generation, or demand response
- the reliability standard referred to in Article 25 of [8].

According to ENTSO-E's guideline [2] (see 6.25 Section 25) the value for VOLL that is used during project assessment should reflect the real cost of outages for system users, hence providing an accurate basis for investment decisions. A level of VOLL that is too high would lead to over-investment, a value that is too low would lead to an inadequate security of supply because the cost of measures to prevent an outage are erroneously weighed against the value of preventing the outage. It is also stated that the experience has demonstrated that estimated values for VOLL vary significantly by geographic factors, differences in the nature of load composition, the type of affected consumers, and the level of dependency on electricity in the geographical area impacted, differences in reliability standards, the time of year and the duration of the outage (see Annex V. page 73 for a selective overview). Therefore, using a general uniform estimation for VOLL would lead to less transparency and inconsistency, and greatly increase uncertainties compared to presenting the physical units.

The EU Regulation on risk-preparedness (see (12) in [9]) points out that monitoring of security of supply for risk-preparedness procedures should be based on two indicators: "expected energy not-served (EENS)" (GWh/year) and "loss load expectation (LLOE)" (hours/year).

The Network code on demand connection [16] introduces several requirements for demand units connected to both transmission and distribution levels, including remotely and autonomously controlled demand response. For the scope of the present paper, it is more interesting that the Code defines the necessity for conducting qualitative and quantitative CBAs prior to implementation of the requirements to various existing demand facilities (see art.4 in [16]). It defines a two-step process: the TSO should proceed to the quantitative part only if the indicated qualitative analysis shows likely benefits will exceed the likely costs. The document also defines the main principles for the CBAs, and among others mentions that the relevant TSO, demand facility owner or prospective owner, DSO/Closed Distribution System Operator (CDSO) (See Glossary, page 56) or prospective operator, shall also quantify socioeconomic benefits in terms of improvement in security of supply and shall include at least:

- the associated reduction in probability of loss of supply over the lifetime of the modification
- the probable extent and duration of such loss of supply
- the societal cost per hour of such loss of supply

Furthermore, a cost-benefit analysis shall be in line with the following principles:

a) the relevant TSO, demand facility owner or prospective owner, DSO/CDSO or prospective operator, shall base its cost-benefit analysis on one or more of the following calculating principles:
   i. the net present value
   ii. the return on investment
   iii. the rate of return
   iv. the time needed to break even
b) the relevant TSO, demand facility owner or prospective owner, DSO/CDSO or prospective operator, shall also quantify socioeconomic benefits in terms of improvement in security of supply and shall include at least:
   i. the associated reduction in probability of loss of supply over the lifetime of the modification
   ii. the probable extent and duration of such loss of supply
   iii. the societal cost per hour of such loss of supply

c) the relevant TSO, demand facility owner or prospective owner, DSO/CDSO or prospective operator, shall quantify the benefits to the internal market in electricity, cross-border trade and integration of renewable energies, including at least
   i. the active power frequency response
   ii. the balancing reserves
   iii. the reactive power provision

In TYNDP2020 report [17] at the moment it is mentioned that this issue will be presented in the next stage of TYNDP2020 (reference to 2018 meanwhile).

There are several monetised indicators, suggested in ENTSO-E's Guideline for CBAs [2], where the closest to be applicable to reliability function is VOLL (value of lost load) (see also Annex II, page 60 for explanation of different categories).

The EU Power System study [11] looks at security of supply (SoS), but it is unclear if the function is monetised or not. Eurelectric in its study "The Value of the Grid" (see page 7 in [12]) refers to reliability as an important property as well as System Average Interruption Duration and System Average Interruption Frequency Indexes without attaching a specific costs function to these.

Present practices for cost functions, representing reliability

In Italy the TSO uses VOLL (in a range from 20 kEUR/MWh to 40kEUR/MWh) to valorise reliability in CBAs. The Slovenian TSO calculates ENS for projects and by using value 10,8 kEUR/MWh (national value). This is then seen as the benefit of the project and is summed up into yearly projects benefits.

From the DSOs' side:

- ENEL explains that the increase in reliability, directly or indirectly, is the goal of the most important projects. In Italy, the three-years Resilience Plan (required by national regulation since 2018) specifically aims at increasing reliability of the power supply even in case of extraordinary weather events. Regarding Costs and Benefits to take in account: performance indicators, related to continuity of supply, have effect on regulated rewards and penalties. Project CBA takes in account operational cost reductions and performance indicator increase, as direct benefit of investment.
- Iberdrola considers the impact in reliability indexes and has to be aligned with our sustainability drivers.
- Netz Niederoesterreich does not use any functions for this.
- For the Lithuanian DSO the CBA is not applicable. Investment priorities go to top-rated lines/objects. DSO has an internal methodology for objects/lines rating.

Discussion

In general, the European Commission insists on using a CBA estimation in all decision-making processes concerning the power industry. This applies to several aspects like risk-preparedness, demand connection and network expansion planning etc. The key indicator for reliability is the lost load, which is monetised via the Value of Lost Load indicator (VOLL). There is a strong indication from ENTSO-E that there is no a uniform estimation for VOLL throughout Europe, and this could lead to less transparency and inconsistency and greatly increase uncertainties compared to using the physical units, as for example GWh/year in Expected Energy Not Supplied (EENS) indicator.

It is truly difficult to arrive to a non-controversial quantification procedure for the VOLL, so as to give comparative values for all EU countries, which depend from many factors. Nonetheless, a pressure should be applied to all the competent Regulatory Authorities so that a consistent approach is applied everywhere in Europe by taking as far as possible into account all the aspects that define the value of the VOLL.

3.3 TSO-DSO interaction

3.3.1 Procedures for TSO-DSO interactions during planning: priority, iteration, sharing of information and models

The IEM Directive (see art.32 in [7]) requires that the development of a distribution system shall be based on a transparent network development plan that the DSO shall publish at least every two years and shall submit to the regulatory authority. The DSO shall consult all relevant system users and the relevant TSOs on the network development plan. The DSO shall publish the results of the consultation process along with the network development plan.

The common TSO-DSO data management report developed five specific Use Case, where one is related to network planning. The report [5] distinguishes between operational (from hour ahead to year ahead) and long-term (from one year ahead and onwards) network planning. In brief, the report defines the following main data exchanges (for details see Section 6 in [5]):

- For planning purposes, DSOs and TSOs shall agree on common assumptions relevant for planning (e. g. economic growth) and common parameters for planning methodology (e. g. definition of connection requirements for grid users, simplified electrical grid models, etc.).
- Information exchange between TSOs and DSOs supporting long-term network development process could include simplified electrical grid models, including foreseen and planned grid expansion projects as well as annual demand/generation forecasts per physical TSO–DSO interface.
- Information exchange between TSOs and DSOs supporting operational planning could include, as long as it respects confidentiality issues, the year-ahead availability plan, outages and business continuity/ emergency plans and information related to upfront activities for operational security analysis. Also, periodically, demand/generation forecasts on the TSO–DSO interface could be exchanged and/or published, which also would facilitate integration of RES and new customer connections. The periodicity of these forecasts' exchanges could evolve over time.

The report further concludes that TSOs and DSOs shall agree on a network planning process, which is adequately synchronised with the Ten-Year Network Development Plan (TYNDP). TSOs and DSOs need, for future network planning (long-term and operational), an even better view of the decentralised generation and its effect on the power flow at the interchange points between TSO and DSO. Information exchange for operational planning will have to be done in the future in a structured way.

The ENTSO-E's Key Organisational Requirements, Roles and Responsibilities (KORR) [4] defines general responsibilities related to operational data exchange (including establishment and maintenance of the communication links) and more specifically:

- Each TSO, DSO or SGU shall be responsible for the quality of the information they provide regarding their power generating modules, demand facilities or services to other parties

TSOs bares the main responsibility for data exchange, as for example:

- TSOs shall communicate to the relevant TSOs and DSOs of its control area the elements of their transmission and distribution networks identified as a part of observability area
- Each TSO shall provide updated information of the DSO network of its control area that is part of the observability area of other TSO to those TSOs.
- Each TSO may provide updated information of the neighbouring TSO networks which have an impact on the distribution networks of its own control area to the DSOs operating those distribution networks
- All transmission and distribution data to be exchanged between TSO control areas shall be exchanged only through TSOs unless otherwise required by national legislation or specific agreements.

TSOs is responsible for notification of changes within its observability area with the neighbouring TSOs: six months before commission, removal or significant modifications of network elements, power generation module or demand facility

TSO in agreement with DSOs in its control area shall specify the detailed content and publish format for real-time data exchange between them related to distribution network's observability area within its control area.

Present practices for TSO-DSO interactions

Two of the TSOs have indicated that they have specific practices for TSO-DSO interaction, and when it comes to TSOs the used priorities are:

- REN uses quality of supply to the load of the DSO and minimization of active power losses. REN also practises regular planning meetings with the DSO. The company shares mostly grid data, rather than models. Otherwise each company i.e. TSO and DSO make their own studies.
- The main procedure at ELES is to call for data every two years for at least 10 years period, where ELES asks DSOs about their network expansion, planned new substations, consumption for each substation, distributed energy generation expansion, reconstructions etc. No further activities take place at the moment at ELES, and the company does not acquire any network data from the DSO.

All four DSOs indicate that they have specific interaction procedures with TSOs:

- For ENEL the main priority is the increase of the reliability of the network through the coordinated planning and construction of new TSO's power lines and DSO's Primary Substations. The company shares with the TSO the annual development plan that contains the interventions for the following 3 years
- For Iberdrola the transmission planning process is a participatory process conducted by Spain's General State Administration, its autonomous communities, its National Commission on Markets and Competition, Red Eléctrica de España and all the sector actors. Society as a whole is also given a say in information and consultation processes. DSO submits transmission development proposals and provides any information that may be needed for TSO technical studies development. The proposal for the transmission grid development shall include a justification report for each new infrastructure that sets out its contribution to the principles defined in the planning, as well as any development alternatives and the reasons that support the option chosen as optimal for the electricity system.
- For Netz Niederoesterreich the main priority is the national Network Development plan, driven by the TSO. In addition, there is the regional DSO network development plan, which is harmonised with the overall one. The company shares with the TSO the 110 kV network data to get a (parallel) network flow calculation in common with the TSO.
- For the Lithuanian DSO the main interaction priorities are related to real-time grid measurement's data sharing, investment planning, coordination of maintenance and grid operation works. The main objectives of interaction between TSO-DSO agreement is to coordinate key grid bottlenecks when connecting customers/generators to medium voltage grid. The company shares with the TSO primary substation's HV and MV measurements data.

More specifically for Italy and regarding useful data exchange, the Italian NRA ARERA recently approved through resolution 36/2020 the "double level" framework for information exchange: DSOs will collect and transmit to the TSO real-time data related to distribute generation resources connected to their network. ARERA is going to launch further consultations to define:

- the most appropriate technological solutions for the data collection and transfer
- responsibility for the development, deployment and maintenance of the solutions
- the timing of implementation of the data exchange, as well as the timing for any retrofit of the existing SGUs and the related cost coverage mechanisms

Discussion

The present situation is that TSOs bear the main responsibility for organizing the interaction with DSOs. There is also an indication that concrete actions and procedures will have to be defined bilaterally between TSO and DSO, where the Data Management report can be used as a common reference point. The "Key Organisational Requirements, Roles and Responsibilities" (KORR) [4] issued by ENTSO-E, naturally represents TSO-specific point of view, while it seems like opinion of DSOs about the future evolution of roles and responsibilities is somewhat underrepresented at the moment.

3.3.2 Sharing of resources between TSO and DSO: what are the priorities?

The IEM Directive (see (9) in [7]) defines that distribution system operators shall cooperate with transmission system operators for the effective participation of market participants connected to their grid in retail, wholesale and balancing markets. Delivery of balancing services stemming from resources located in the distribution system shall be agreed with the relevant transmission system operator.

Eurelectric [12] defines the necessity, but does not specify the details: In order to sensibly exploit the potential of flexibility management, curtailment and re-dispatch, a conducive regulatory framework and coordination mechanisms are needed. With this objective, coordinating the use of flexibility between DSO and TSO to optimise the use of the grid will be a major achievement.

Discussion

At present, there is no common regulatory or practice background allowing to draw clear conclusions on this topic. This necessity is clearly highlighted both at the institutional level and by the stakeholders.

3.3.3 Responsibilities for congestion management and balancing

According to the IEM Directive (see (7) in [7]) while performing its main tasks (the efficient, reliable and secure operation of the distribution system), the DSO shall procure the non-frequency ancillary services needed for its system in accordance with transparent, non-discriminatory and market-based procedures, unless the regulatory authority has assessed that the market-based provision of non-frequency ancillary services is economically not efficient and has granted a derogation.

TSO is responsible for ensuring a secure, reliable and efficient electricity system (see art.40 in [7]) and, in that context, for ensuring the availability of all necessary ancillary services, including those provided by demand response and energy storage facilities. TSO shall procure balancing services subject to the following:

- transparent, non-discriminatory and market-based procedures
- the participation of all qualified electricity undertakings and market participants, including market participants offering energy from renewable sources, market participants engaged in demand response, operators of energy storage facilities and market participants engaged in aggregation.

ENTSO-E's guideline on CBAs [2] presumes that responsibility for balancing and congestion management is TSOs' responsibility. The same opinion is presented in another ENTSO-E's document " European Power System 2040: Completing the map" [11].

The common TSO-DSO ASM report (see Sections 2.5 and 7.1 in [10]) defines that: system operators are responsible for facilitation of the market (access to, compliance with regulation, participation of all market parties, physical connection). TSO-DSO coordination is essential. Independent of the model chosen, to perform congestion management and trade active power services for the grid and service needs, system operators should exchange all the relevant information from their grid and the relevant connected assets, from structural data (potential flexibility services and their characteristics) to more dynamic data (forecast and activation of the bids) this is needed to allow flexibility procurement without disturbing the grid. The document also defines three alternative models (coordination schemes) for balancing and congestion management.

Another common TSO-DSO document (see page 21 in [5]) mentions that TSOs and DSOs can perform congestion management, while ensuring no harmful interference with system balancing by the TSOs or with congestion management of any other System Operator. TSOs and DSOs should be responsible for qualifying, certifying and validating the execution of the flexibility services contracted. The guideline for TSO-DSO cooperation [13] outlines the future responsibilities for the operators:

- TSOs - maintaining overall system security via frequency control, LFC block balancing and congestion management (across borders and on the TSO level) and voltage support in the transmission network in an electricity system
- DSOs- managing voltage stability and congestion on their grids

Eurelectric [12] looks at Microgrids and in particular Citizens Energy Communities (CEC) as an important future resource, which can be endorsed with new duties (especially balancing responsibility) when acting either as a supplier, as an active customer, as a DSO, or as any other system user.

The IEM Directive in (see art. 32 in [7]) put specific responsibilities for DSOs and TSOs for preparation of network development plans and considering flexible resources in the process, as it has been already mentioned in Section 3.1.1.

Discussion

The overall evolution of roles and responsibilities depends upon the time horizon. In the first 10-20 years it is reasonable to suppose that TSOs will remain responsible for system balancing and congestion management in their own networks, while DSOs will have to deal with congestion in the distribution networks. It is also worth mentioning that the European Commission has started the formalisation process of several new business actors, including so-called Citizens Energy Communities (CEC) by indicating their roles and responsibilities in the IEM Directive [3]. Eurelectric looks at Microgrids and in particular CECs as an important future resource, which in the future can be endorsed with new duties, especially local balancing responsibility.

3.3.4 Roles and responsibilities related to network expansion planning

The IEM Directive [7] defines the main principles for network development stating that:

- DSO (see art.32 in [7]): The network development plan shall provide transparency on the medium and long-term flexibility services needed, and shall set out the planned investments for the next five-to-ten years, with particular emphasis on the main distribution infrastructure which is required in order to connect new generation capacity and new loads, including recharging points for electric vehicles. The network development plan shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion.

- TSO (see art.51 in [7]): At least every two years, transmission system operators shall submit to the regulatory authority a ten-year network development plan based on existing and forecast supply and demand after having consulted all the relevant stakeholders. That network development plan shall contain efficient measures in order to guarantee the adequacy of the system and the security of supply. The transmission system operator shall publish the ten-year network development plan on its website.

As it was previously mentioned, another TSO-DSO common report [5] defines several high level use cases, involving interactions between TSOs and DSOs, where the most relevant is "Network Planning" use case, which gives an overview of processes related to network planning and the related data exchange between TSOs and DSOs. It takes the existing roles & responsibilities as identified in the “roles toolbox” as a starting point. The main steps in the use case are:

- (Customer driven) request for the connection of a new load/generator facility or the adjustment of an existing one towards the TSO or DSO.
- Forecast of the evolution of the demand and production on the distribution and transmission grid, resulting in a forecast of the power exchange on every connection point between the distribution and transmission system.
- Load flow analyses to determine the possible existing and future relevant bottlenecks.
- Detection of other needs: refurbishment due to grid ageing, environmental or safety concerns, etc.
- If needed, joint TSO–DSO analysis to find the optimal solution for the detected bottlenecks.
- Include the needed projects in the investment program.
- Realisation of the program and reporting for the concerned stakeholders.

Typically, TSOs and DSOs have a common planning cycle process, in which once every [x] year(s) a [y] year forward looking plan is agreed with a granularity of [z] year (e.g. in Netherlands: x = 2, y = 10, z = 1). The document also provides an overview of information that needs to be exchanged TSO, DSO and identified third parties (for details se [5]).

Guidelines for TSO-DSO cooperation [13] mentions that specifically with regard to network planning procedures, DSOs and TSOs should:

- exchange DER forecast to optimise power flows at the T/D connection point and work together to increase public acceptance of network construction projects
- work together in defining technical requirements for new technologies and ancillary services
- align network planning at the TSO/DSO interface

Discussion

The necessity of common TSO-DSO interaction in network planning process seems to be recognised by all parties. More specific details in the interaction are likely to be defined following implementation and maturing of the process.

3.3.5 Technology maturity level, flexibility technologies

The network code on demand connection defines several requirements related to new technical capabilities of demand [16]:

- All transmission-connected demand facilities and transmission-connected distribution systems shall fulfil a set requirement related to low frequency demand disconnection functional capabilities (see art.19 in [16]).
- Low voltage demand disconnection functional capabilities, should follow a set of requirements (may be specified by TSO) i.e. not compulsory
- Blocking of on load tap changers

It is interesting to mention that these requirements are closely connected to CBA analysis, mentioned in Section 3.2.4.

In TYNDP2020 [17] the three presented scenarios make certain assumptions about cost development for different technologies and corresponding levelized cost of electricity (LCOE) (see Glossary, page 56). Development of marginal prices for different technologies is differentiated according to scenarios.

Eurelectric [12] states that the digitalisation of the grid requires significant investments in advanced sensors, protections to control voltage and frequency to better stabilise the network, new algorithms for load flows and weather predictions.

Discussion

ENTSO-E's network code on demand connection opens for connection of loads, which support disconnection capabilities (automatic or remotely controlled), by defining specific technical requirements In TYNDP framework the scenarios include assumptions about cost development for different technologies and corresponding levelized cost of electricity.

It is also necessary to mention that there is an on-going public consultation by the European Commission (open until 2020-05-14) related to development of new network codes, and code on demand side flexibility is mentioned as one of them. However, the drafting process might not start before 2022.

3.4 Other

3.4.1 Incentivisation mechanisms for flexibility resources

The IEM Directive (see art.17 in [7]) establishes limits for compensations, to market participants or balance responsible parties, for disturbances due to Demand Response Activation. The financial compensation shall be strictly limited to covering the resulting costs incurred by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response. The method for calculating compensation may take account of the benefits brought about by the independent aggregators to other market participants and, where it does so, the aggregators or participating customers may be required to contribute to such compensation but only where and to the extent that the benefits to all suppliers, customers and their balance responsible parties do not exceed the direct costs incurred. The calculation method shall be subject to approval by the regulatory authority or by another competent national authority.

This issue is further elaborated in art. 32 of the same document, saying that Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system. In particular, the regulatory framework shall ensure that distribution system operators are able to procure such services from providers of distributed generation, demand response or energy storage and shall promote the uptake of energy efficiency measures.

The above-mentioned terms are supported by Eurelectric in its position paper [1]. Furthermore, Eurelectric in its study [15] discusses incentivisation mechanisms, which are embedded in the national regulation regimes and encourage funding of pilot projects. The study asks to recognise the special character of innovative investments. The efficiency requirements should consider the higher technology risks. Incentives for capital expenditure (CAPEX) and operational expenditure (OPEX) should be treated equally, R&D should be removed from OPEX efficiency targets, encouraging DSOs to innovate.

In "The value of the grid" document from Eurelectric [12] incentivisation is not mentioned specifically, however customers have also the potential to be remunerated for providing flexibility services to the system and create additional revenues for themselves. When it comes to CEC, these communities can be useful flexibility sources for distribution grid, and there are ways for partnership to be further developed and to achieve benefits from mutual cooperation. EV batteries can be used to help stabilise the grid while their owners are remunerated for this service.

Discussion

In general, the flexible resources can be an asset operated directly by the system operator or can be procured from external providers, as for example independent aggregators. From the regulatory point of view there is a protective measure, limiting the potential compensations for demand response providers, which is relevant to both categories. The method for calculating compensation may take account of the benefits brought about by the independent aggregators to other market participants and, where it does so, the aggregators or participating customers may be required to contribute to such compensation but only where and to the extent that the benefits to all suppliers, customers and their balance responsible parties do not exceed the direct costs incurred.

Several national regulating provisions have already embedded incentive mechanisms for DSOs for investment into flexibility services. It is difficult to see any other specific incentives for the time being.

There are however a lot of on-going sandboxes involving flexibility and they could result in a need for improving the present regulation.

3.4.2 Criteria for development of scenarios time horizon and other details

The Regulation on IEM (see art.48 [8]) defines that the Union-wide network development plan shall include the modelling of the integrated network, scenario development and an assessment of the resilience of the system. The Union-wide network development plan shall, in particular:

- build on national investment plans, taking into account regional investment plans as referred to; it shall be subject to a cost-benefit analysis using the methodology established for VOLL
- regarding cross-border interconnections, also build on the reasonable needs of different system users and integrate long-term commitments from investors referred to in Articles 44 (Independent System Operator) and 51 (Network development and power to make investment decisions) of Directive (EU) 2019/944 [7]
- identify investment gaps, in particular with respect to cross-border capacities

In TYNDP2020 methodological report [17] ENTSO identified two main drivers to develop their scenario storylines: decarbonisation and centralisation/decentralisation. Decarbonisation refers to the decline in total GHG emissions while centralisation/decentralisation refers to the set-up of the energy system, such as the share of large/small scale electricity generation (offshore wind vs. solar PV) or the share of indigenous renewable gases (biomethane and power to gas (P2G)) vs. share of decarbonised gas imports (either pre- or post-combustive). For 2020 and 2025, all scenarios are based on bottom-up data from the TSOs called the “Best Estimate” Scenario and reflecting current national and European regulations. There are three different storylines for 2030 and 2040/2050:

- **National Trends (NT)** is the central scenario based on draft NECPs in accordance with the governance of the energy union and climate action rules, as well as on further national policies and climate targets already stated by the EU member states. Following its fundamental principles, NT is compliant with the EU’s 2030 Climate and Energy Framework (32 % renewables, 32.5 % energy efficiency) and EC 2050 Long-Term Strategy with an agreed climate target of 80–95 % CO2 reduction compared to 1990 levels.
- **Global Ambition (GA)** is a scenario compliant with the 1.5° C target of the Paris Agreement also considering the EU’s climate targets for 2030. It looks at a future that is led by development in centralised generation. Economies of scale lead to significant cost reductions in emerging technologies such as offshore wind, but also imports of energy from competitive sources are considered as a viable option.
- **Distributed Energy (DE)** is a scenario compliant with the 1.5° C target of the Paris Agreement also considering the EU’s climate targets for 2030. It takes a de-centralised approach to the energy transition. A key feature of the scenario is the role of the energy consumer (prosumer), who actively participates in the energy market and helps to drive the system’s decarbonisation by investing in small-scale solutions and circular approaches.

ENTSO-E's guidelines [2] for CBA describe that construction of scenarios is a starting point for the assessment process. Scenarios are constructed at the level of the European electricity system and can be adapted in more detail at a regional level. The scenarios reflect European and national legislations in force at the time of the analysis and consider plausible energy futures characterised by, amongst others, generation portfolios, demand forecasts and exchange patterns with the systems outside the study region etc. The objective is to construct contrasting future developments that differ enough from each other to capture a realistic range of possible futures that result in different challenges for the grid.

Scenarios can be distinguished depending on the time horizon:

- Mid-term horizon (typically 5 to 10 years): mid-term analyses should be based on a forecast for this time horizon
- Long-term horizon (typically 10 to 20 years): long-term analyses will be systematically assessed and should be based on common ENTSO-E scenarios
- Horizons which are not covered by separate data sets will be described through interpolation Techniques.

The scenarios developed in a long-term perspective may be used as a bridge between mid-term horizons and very long-term horizons (n+20 to n+40). The aim of the perspectives beyond n+20 should be that the pathway realised in the future falls within the range described by the scenarios within reasonably possible expectations. The scenarios on which to conduct the assessment of the projects will be given for fixed years and rounded to full 5 years (e.g. 2025 instead of 2023 for n+5 in TYNDP 2018). For the mid-term horizon the scenarios have to be representative of at least two study years. For example, for the TYNDP 2020 the study years of the mid-term horizon are 2025 (n+5) and 2030 (n+10).

From another point of view, the Regulation on risk preparedness [9] defines that methodology for development of risk identification includes development of regional electricity crisis scenarios, based on a common approach. Detailed methodology to be developed by ENTSO-E and submitted to ACER.

The EU Power system 2040 [11] develops three Pan-European scenarios for 2040, where the European climate targets are met or exceeded:

- Global Climate action
- Sustainable Transition
- Distributed Generation

Two-step approach made up of a "market" study, followed by a detailed network study is applied. The market study is based on a flow-based model, similar to one from e-Highway 2050. The next step - network approach i.e. network simulation to analyse if the capacity increases suggested by the market study increased the network bottlenecks.

Present practices for development of scenarios

All responded TSOs indicated that they develop specific scenarios:

- REN develops ten-year development plan, every two year to the regulator and public authorities.

- TERNA's scenarios are developed in collaboration with the main Italian Gas TSO, estimating the electricity and gas supply and demand, on a twenty-year horizon.
- ELES makes a national development plan every 2 years. For the past years the company used 4 scenarios, which are aligned with Slovenian governmental documents and with ENTSO-E scenarios. Currently the company has started a new process, where at least one scenario will be NECP compliant. For each scenario network analysis are made and if there are overloads or congestions, one or more technical solutions are presented, which are furthermore analysed not only by technical means, but also techno-economic analyses, so in the end only one expansion solution is selected.

All responded DSOs develop scenarios for evaluation of the expansion plans.

- At ENEL the expansion plans are developed considering short term-scenarios of load and generation growth (economic growth and government incentives are the key factors for demand and generation forecast) and long-term technological improvement and regulatory evolution.
- At Iberdrola the investments Plan for the next 3 years must be submitted and approved by the local governments (CCAA). It must also be approved by the government, after an evaluation by the CNMC, which is The National Commission on Markets and Competition, that promotes and defends proper functioning of all markets, in the interest of consumers and businesses.
- For the Austrian DSO the confirmed wind generation requests are one parameter, aggregated load at substations come from experience of the past and forecasting of the two-year future. Third, the big requests of industrial plants are included.

Discussion

The prevailing practice for TSOs is to use (fully or partially) the methodology of the TYNDP. The situation is somewhat more difficult for the DSOs, probably because they are directly interfaced with final users and local communities, so their plans will in many ways depend upon the development on the consumption side.

3.4.3 Reliability criteria for system planning n-1 vs. probabilistic: different national practices, implementation timeline (compared to FlexPlan)

The Guideline on risk preparedness [9] points out that development of the scenarios should go beyond N-1 and consider accidental hazards.

The EU Power system 2040 report [11] applies n-1 approach.

Present practices for reliability criteria

TERNA has already implemented a probabilistic approach for the evaluation of the benefit related to Energy Not Supplied (ENS). ELES is in a process of implementing probabilistic methods for planning. This enables ELES to have a better overview of the circumstances in the network. The company is however very cautious doing this and N-1 criteria remains important for now.

- REN uses the following reliability criteria: continuity of supply, grid losses, minimization of TOTEX, environmental impact, etc. In addition, REN employs a contingency analysis including full N-1 analysis and N-1-1 (or N-2) analysis, for some grid elements considered as high importance (e.g. applied to all 400 kV lines). These rules are defined in the Portuguese Regulation for Transmission Network (Law 596/2010).
- In the Italian CBA methodological document, it is explained that N-1 or probabilistic criteria are used case by case for planning network development projects in reliability. However, according to TERNA the N-1 evaluation criterion is now used only for small portions of the network, while the probabilistic method is the one commonly used in the CBA for project evaluation.
- ELES calculates loss of load expectation (LOLE and ENS) for each of planning scenarios. Furthermore, the company makes great efforts in analysing the effect of distributed energy resources, especially EV on transmission grid in the future.

None of the DSO has national plans for replacing n-1 with probabilistic criteria in the planning activities.

- For ENEL the planning process follows primarily the connection requests of customers. When connection requests are satisfied, the network development responds to quality of power supply criteria: reliability N-1 (grid meshing aims to guarantee the counter-power supply of feeders) and probabilistic (foreseeable scenarios).
- Iberdrola assures quality requirements for security and continuity of supply under normal conditions and in general under N-1.
- The Austrian DSO considers the seriousness of the requests on bigger generation and consumption sites.
- The Lithuanian DSO relies solely on n-1.

Discussion

TSO practice shows that n-1 is commonly used as a reliability criterion. The collected feedback about existing practice shows gradual implementation of probabilistic methodologies by some TSOs. Depending upon the overall success of the first implementations, this may result in common transfer to the probabilistic approach.

3.5 Additional points

The most recent version of ENTSO-E's [2] guideline denotes that flexibility of demand is considered as a part of for estimation of socio-economic welfare. For assessing the socio-economic welfare there are two ways of taking into account greater flexibility of demand:

1. Demand is estimated through scenarios, which results in a reshaping of the demand curve (in comparison with present curves) to model the future introduction of smart grids, electric vehicles, etc. In this case, demand response is not elastic at each time step, but constitutes a shift of energy consumption from time steps with potentially high prices to time steps with potentially low prices (e.g. on the basis of hourly RES availability factors). The generation costs to supply a

known demand are minimised through the generation cost approach. This assumption simplifies the complexity of the model and therefore the demand can be treated as a time series of loads that has to be met, while at the same time considering different scenarios of demand-side management.

2. Introduce hypotheses on level of price elasticity of demand. Two methods are possible:

a) Using the generation cost approach, price elasticity could be taken into account via the modelling of curtailment as generators. The willingness to pay would then, for instance, be established at very high levels for domestic consumers, and at lower levels for a part 47 of industrial demand.

b) Using the total surplus method, the modelling of demand flexibility would need to be based on a quantification of the link between price and demand for each hour, allowing a correct representation of demand response in each area.

4 Conclusions

Summarising the screening process above and bearing in mind the overall picture, it seems evident that the European Commission strongly emphasises efficiency in different activities of the power system. Utilisation of the already existing resources as demand response can reduce the necessity for new investments. The Commission therefore demands consideration of the existing resources as a consistent part network expansion planning and considering demand response and storage with the same priority as generation in dispatching and redispatching procedures. Furthermore, the necessity to apply market-based mechanisms whenever possible is underlined in several regulatory documents with reference to many network operative aspects, as for example for the procurement of resources for ancillary services or even for system defence and restoration services. Finally, application of CBAs is put forward as a unified justification criterion to activate new investments. At the very same time it is necessary to mention that Commission shows a very pragmatic approach on several critical issues, as for example the above-mentioned issues related to ownership and operation of energy storage. The most recent recast of the IEM Directive shows modifications of the terms and introduction of new actors as CECs. Possibly, the final solution will emerge at the end of a learning process connected to technologic maturity

It is clear that the methodological efforts by ENTSO-E in developing network codes and guidelines have greatly contributed to a common understanding and approaches among the European TSOs. On some issues, however, there is a clear disagreement between TSOs and DSOs, like for example costs allocation. FlexPlan has probably to consider both points of view and make evaluations on a case-to-case basis.

The third version of ENTSO-E's CBA guideline describes the common principles and procedures for performing combined multi-criteria and cost-benefit analysis using network, market and interlinked modelling methodologies for developing Regional Investment Plans and the Union-wide TYNDP. The present practice at TSOs is mostly pre-determined by the Guidelines from ENTSO-E, even though there is a certain variation in application of it. It is also important to repeat the point, made by ENTSO-E in its CBA guideline: costs mostly depend on scenario independent factors like routing, technology, material, etc., benefits strongly correlate with scenario specific assumptions. On DSOs side the practice seems to be much less standardized, even with preference of multi-criteria approaches.

Another important issue is the assessment of the reliability indicator (VOLL). According to ENTSO-E's guideline the value for VOLL that is used during project assessment should reflect the real cost of outages for system users, hence providing an accurate basis for investment decisions. It is also stated that the experience has demonstrated that estimated values for VOLL vary significantly in dependency of geographic factors, differences in the nature of load composition, the type of affected consumers, and the level of dependency on electricity in the impacted geographical area, differences in reliability standards, the time of year and the duration of the outage.

Regarding the evolution of roles and responsibilities, in a 10-20 years' timeframe it is reasonable to suppose that TSOs will remain responsible for system balancing and congestion management in their respective networks, while DSOs will be allowed to deal with congestion in their own distribution network. It is also worth mentioning that the European Commission has started the formalisation process of several new business actors, including so-called Citizens Energy Communities. The introduction of these new actors could change the landscape and roles/procedures applied both in the planning and in the operation phases.

Finally, it must be remarked that there are strong regulatory signals prompting European system operators to consider flexible resources as a new important active subject in the grid expansion planning process for. Despite strong efforts from ENTSO-E to develop common methodologic principles, there are still several missing elements in the puzzle. This strengthens once again the importance and proper timing of FlexPlan project, both for testing new innovative grid planning methodologies coping with the present challenges, for the comprehensive scenario assessment up to 2050 and for the final synthesis of the results into regulatory guidelines brought to the attention of National Regulators and the Commission.

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FlexPlan

6 Annex I: Glossary

Active customer	a final customer, or a group of jointly acting final customers, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity [7]
Ancillary service	a service necessary for the operation of a transmission or distribution system, including balancing and non-frequency ancillary services, but not including congestion management [7]
Citizen Energy Community	a legal entity that: (a) is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises (b) has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; and (c) may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders; [7]
Closed Distribution System	a distribution system, which distributes electricity within a geographically confined industrial, commercial or shared services site and does not supply household customers, without prejudice to incidental use by a small number of households located within the area served by the system and with employment or similar associations [16]
Common grid model	a Union-wide data set agreed between various TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process [18]
Cross-border flow	means a physical flow of electricity on a transmission network of a Member State that results from the impact of the activity of producers, customers, or both, outside that Member State on its transmission network [8]
Curtailed Electricity	Curtailment is a reduction in the output of a generator from otherwise available resources (e.g. wind or sunlight), typically on an unintentional basis.

	Curtailments can result when operators or utilities control wind and solar generators to reduce output to minimize congestion of transmission or otherwise manage the system or achieve the optimum mix of resources.
Demand Response Active Power Control	demand within a demand facility or closed distribution system that is available for modulation by the relevant system operator or relevant TSO, which results in an active power modification [16]
Demand Response Reactive Power Control	reactive power or reactive power compensation devices in a demand facility or closed distribution system that are available for modulation by the relevant system operator or relevant TSO [16]
Demand Response System Frequency Control	demand within a demand facility or closed distribution system that is available for reduction or increase in response to frequency fluctuations, made by an autonomous response from the demand facility or closed distribution system to diminish these fluctuations [16]
Demand Response Transmission Constraint Management	demand within a demand facility or closed distribution system that is available for modulation by the relevant system operator or relevant TSO to manage transmission constraints within the system [16]
Demand Response Very Fast Active Power Control	demand within a demand facility or closed distribution system that can be modulated very fast in response to a frequency deviation, which results in a very fast active power modification [16]
Demand Units	an indivisible set of installations containing equipment which can be actively controlled by a demand facility owner or by a CDSO, either individually or commonly as part of demand aggregation through a third party [16]
Energy storage facility	the electricity system, deferring the final use of electricity to a moment later than when it was generated, or the conversion of electrical energy into a form of energy which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy carrier [7]
Flexibility	Active management of an asset that can impact system balance or grid power flows on a short-term basis (from day-ahead to real time). Flexibility can be provided by different assets. The first three can be both directly or through an aggregator: • generation (part of the dispatchable units, RES); • load facilities (involved in a demand response programme); • storage (pumped storage power station, batteries, etc.); and/or

	• interconnectors (intraday energy exchanges). Flexibility can be used by: • the TSO for balancing and congestion management in the short term and planning in long-term contracting • the DSO for congestion management in the short term and planning in long-term • contracting and/or • the BRP for portfolio management both in the short and long term (investment) [5]
Flexibility (Demand Side)	changes in energy use by end-use customers (domestic and industrial) from their current/normal consumption patterns in response to market signals such as time variable electricity prices or incentive payments or in response to acceptance of the consumer's bid, alone or through aggregation, to sell demand reduction/increase at a price in organised electricity markets [5]
Flexibility (System)	characterises the impact of the project on the ability of exchanging balancing energy in the context of high penetration levels of non-dispatchable electricity generation [2]
Individual grid model	a data set describing power system characteristics (generation, load and grid topology) and related rules to change these characteristics during capacity calculation, prepared by the responsible TSOs, to be merged with other individual grid model components in order to create the common grid model [18]
Levelised Cost of Electricity	Levelised costs of electricity. It represents the average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant during an assumed financial life and duty cycle [17]
Market congestion	a situation in which the economic surplus for single day-ahead or intraday coupling has been limited by cross-zonal capacity or allocation constraints [18]
Non-frequency ancillary service	a service used by a transmission system operator or distribution system operator for steady state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability [7]
Non-market-based measure	any supply- or demand-side measure that deviates from market rules or commercial agreements, the purpose of which is to mitigate an electricity crisis (in the context of [9])
Observability Area	a TSO's own transmission system and the relevant parts of distribution systems

	and neighbouring TSOs' transmission systems, on which the TSO implements real-time monitoring and modelling to maintain operational security in its control area including interconnectors [19]
Physical congestion	any network situation where forecasted or realised power flows violate the thermal limits of the elements of the grid and voltage stability or the angle stability limits of the power system [18]
Scenario	i. the forecasted status of the power system for a given time-frame [18] ii. a description of plausible futures, characterised by, amongst others, generation portfolio, demand forecast and exchange patterns with the system outside the study region [2]
Structural congestion	congestion in the transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently reoccurring under normal power system conditions [18]
Value of lost load (VOLL)	a measure of the costs associated with unserved energy (the energy that would have been supplied if there had been no outage) for consumers. It is generally measured in €/kWh. It reflects the mean value of an outage per kWh (long interruptions) or kW (voltage dips, short interruptions), appropriately weighted to yield a composite value for the overall sector or nation considered [2]

7 Annex II: Explanation of categories for project assessments

The following section quotes from ENTSO-E's 3rd Guideline [2]

Benefits:

- **B1. Socio-economic welfare (SEW from wholesale energy market integration)** is characterised by the ability of a project to reduce (economic or physical) congestion. It thus provides an increase in transmission capacity that makes it possible to increase commercial exchanges, so that electricity markets can trade power in a more economically efficient manner.
- **B2. Additional societal benefit due to CO2 variation** represents the change in CO2 emissions in the power system due to the project. It is a consequence of changes in generation dispatch and unlocking renewable potential. The EU has defined their climate policy goals by reducing the greenhouse gas emissions by at least 40% until 2030 compared to the 1990 levels. As CO2 emission is the main greenhouse gas coming from the electricity sector, they are displayed as a separate indicator. This indicator takes into account the additionally societal costs of CO2 emissions.
- **B3. RES integration**: Contribution to RES integration is defined as the ability of the system to allow the connection of new RES generation, unlock existing and future "renewable" generation and minimising curtailment of electricity produced from RES. RES integration is one of the EU 2030 goals which set the target of increasing the share of RES to 32% with respect to the overall energy consumption.
- **B4. Non-direct greenhouse emissions** represent the change in non-CO2 emissions (e.g. COX, NOX, SOX, PM 2, 5, 10) in the power system due to the project. It is a consequence of changes in generation dispatch and unlocking renewable potential.
- **B5. Grid losses** in the transmission grid is the cost of compensating for thermal losses in the power system due to the project. It is an indicator of energy efficiency and expressed as a cost in euros per year.
- **B6. Security of supply:** Adequacy characterises the project's impact on the ability of a power system to provide an adequate supply of electricity to meet demand over an extended period of time. Variability of climatic effects on demand and renewable energy sources production is taken into account.
- **B7. Security of supply:** Flexibility characterises the impact of the project on the ability of exchanging balancing energy in the context of high penetration levels of non-dispatchable electricity generation. Balancing energy refers to products such as Replacement Reserve (RR), manual Frequency Regulation Reserve (mRR) and automatic Frequency Regulation Reserve (aFRR). Exchanging/Sharing balancing capacity (RR, mFRR and aFRR), which requires guaranteed/reserved cross zonal capacity, is also taken into account.
- **B8. Security of supply:** Stability characterises the project's impact on the ability of a power system to provide a secure supply of electricity as per the technical criteria.
- **B9. Avoidance of the Renewal / Replacement Costs of Infrastructure** characterises the benefit

a project can bring by avoiding or deferring replacing or upgrading already existing infrastructure.

B10. Synchronization with Continental Europe (CE) is understood as safeguarding operational security, preventing the propagation or deterioration of an incident to avoid a widespread disturbance and the blackout state as well to allow for the efficient and rapid restoration of the electricity system from emergency or blackout states. Small systems (e.g. Baltic States) or poorly connected systems (regions) to face with major issues: work in "island" mode or strongly reliant on third countries' infrastructure. Therefore, synchronization with CE usually leads to improved system security and economy of operation.

B11. Redispatch Reserves or Reduction of Necessary Reserves for Redispatch Power Plants characterizes the project's impact on needed contracted redispatch reserve power plants by assessing the maximum power of redispatch with and without the project. Prerequisite for this indicator is the use of redispatch simulations.

Costs:

C1. Capital expenditure (CAPEX). This indicator reports the capital expenditure of a project, which includes elements such as the cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, ground, preparatory work, designing, dismantling, equipment purchases and installation. CAPEX is established by analogous estimation (based on information from prior projects that are similar to the current project) and by parametric estimation (based on public information about cost of similar projects). CAPEX is expressed in euros.

C2. Operating expenditure (OPEX). These expenses are based on project operating and maintenance costs. OPEX of all projects must be given on the actual basis of the cost level with regard to the respective study year (e.g. for TYNDP 20 the costs should be given related to 2020) and expressed in euro per year.

Residual impacts:

S1. Residual Environmental impact characterises the (residual) project impact as assessed through preliminary studies and aims at giving a measure of the environmental sensitivity associated with the project.

S2. Residual Social impact characterises the (residual) project impact on the (local) population affected by the project as assessed through preliminary studies and aims at giving a measure of the social sensitivity associated with the project.

S3. Other impacts provide an indicator to capture all other impacts of a project.

The 3rd Guideline [2] describes the common principles and procedures for combined multi-criteria and cost-benefit analysis using network, market and interlinked modelling methodologies. The guideline has to be used to assessment of reinforcements and extensions of the existing transmission networks.

The guideline, which has been developed as a part of TYND2020 process, refers to market simulations as a part of the CBA, where these are used for calculate the cost optimal dispatch of generation units under the constraint that the demand for electricity is fulfilled. The simulations should consider among other things several constraints such as flexibility and availability of thermal units (only).

8 Annex III: Description of the CBA Methodology Implemented by Italian TSO TERNA

8.1 Introduction

TERNA implemented since 2018 a new Cost Benefit Analysis methodology called ACB 2.0, which is subdivided into the following steps and sub-steps:

1. Identification and quantification (i.e. with a quantitative description) of the benefits, in terms of positive impact
2. Economic quantification of the benefit considered (by multiplying the result of point 1. by a specific economic factor)
3. Quantitative estimation of the costs
4. Calculation of the following economic synthesis indexes:
    a. System Benefit Index (IUS – *Indice Utilità di Sistema*): ratio between actualized benefits and actualized costs for each investment
    b. Present Net Value (VAN – *Valore Attuale Netto*): net value of the actualized benefits resulting from each investment

The methodology is applied to all investments of Terna's Development Plan with estimated costs higher than or equal to 15M€.

Results are updated if new elements become available during the different phases of the investment (planning, agreement, design…) or depending on the biannual update of the scenarios on which the CBA is based.

Every year Terna accompanies the Development Plan with a methodological document to take into account refinements or further additions to the "ACB 2.0" methodology.

8.2 System Development Scenarios

The TSO bases its CBA on the latest available European scenarios. In particular, three kinds of reference year are taken into account

a. short-medium term horizon (3-6 years after the publication of the Development Plan), for which, given the limited uncertainty, only one reference scenario is considered
b. medium-long term horizon (7-11 years after the publication of the Development Plan), for which at least two contrasting scenarios are considered
c. long term horizon (over 11 years following the year of preparation of the Development Plan), of which at least two contrasting scenarios are considered (the TSO can modify the assumptions, under proper and documented motivations).

For each intervention, the methodology analyses the benefit curve in the study years following the expected date of commissioning of the project.

In particular:

1. the interventions with expected completion date less than the short-term study year are analysed in at least two study years between the short, medium-long and long one term.
2. interventions with expected completion date greater than or equal to the short-term study year and less than the medium-long term study year are analyzed in the medium-long and long-term study years.
3. interventions with an expected completion date greater than or equal to the medium-long term are analyzed in the long-term study year.

It is also possible to perform sensitivity analyses on the projects that are considered particularly complex.

8.3 Tools

The CBA is based on the following two kinds of tools:

i. market simulation tools, which do not consider the topological detail of the transmission network (TN)
ii. network simulation tools, which, on the contrary, consider the topological detail of the TN

8.3.1 Market simulation tools

Market simulation tools are based on economical optimization mathematical models of the electricity markets, with a yearly time horizon. The aim is to estimate the hydro and thermal generation costs and the zonal market prices and, as a consequence, the socio-economic surplus of the System.

The optimal dispatching of the hydro-thermal units is performed in two phases: first, the thermal unit commitment is defined, taking into account the technical constraints of the generation units (both thermal and hydro) and of the System (such as, the network constraints); then the optimal hydro-thermal generation is calculated, considering the above mentioned constraints, minimizing the generation costs.

Inputs of the market simulations are:

- model of the equivalent network
- load profile, that is imposed
- hydro and thermal generation units' description, including bid-up
- fuels description and emission trading system (ETS)
- Non-programmable RES generation profiles, that are imposed
- Import/export profiles, that are imposed

8.3.2 Network simulation tools

Two kinds of network simulations are performed:

- **static load flow analyses:** consist on assessing one or more “snapshots” of the power system in particular situations; the network is here represented as nodes, that can be generation node, consumption nodes or simple pass-through nodes, connected by the network elements, i.e. lines, transformers, condensers, loads, reactors, all with topological and technical details; results of these analyses are voltage profiles in the network nodes, active and reactive power flowing through the network elements ad active and reactive losses, so that it is possible to catch out overloads and violation of any technical constraint;

- **probabilistic analyses**: allows to select randomly a state of the Power System starting from the unavailability rate of each network element and generation unit; the fulfilment of the load is granted and the generation units are activated by economic merit order; it is possible to take into account a very large number of contingencies (included *N-k* events) by performing a corresponding number of simulation, each one weighted by its probability. This kind of approach is used particularly in those studies assessing contemporary multiple benefits and/or multiple interventions on the same portion of the network.

The network elements unavailability data are defined starting from historical data.

8.4 Benefits analysis

The benefits of each intervention are evaluated singularly, by comparing the results of the simulation with and without it, both for network and market simulations. *The Take Out One at the Time* (TOOT) approach is used: the reference case is the one with all the intervention implemented, which is compared with the case where the considered intervention is not implemented.

The opposite approach, *Put IN one at the Time* (PINT), is sometimes used to highlight interdependencies of different interventions; here, the reference case is without any intervention and is compared with the case of the implementation of the intervention under assessment only.

All the needs of the System have to be considered, ancillary services as well as the impact on the ancillary services market included.

8.4.1 Benefits categories

Benefits are grouped under the following specific categories:

B1 change in the Socio-Economic Welfare, which is evaluated by means of market simulations; it is positive if there is an increase;

B2.a change in network losses evaluated by means of probabilistic simulations; it is positive if there is a decrease;

B2.b change in network losses evaluated by means of simplified load flow calculations at peak load; it is positive if there is a decrease;

B3.a change in the energy not provided evaluated by means of probabilistic simulations; it is positive if there is a decrease;

B3.b change in the energy not provided evaluated by means of statistic load flow simulations; it is positive if there is a decrease;

B4 avoided generation costs, paying attention to avoid double counting with B1 and B7;

B5.a higher RES integration, which includes the reduction in local congestion calculated with probabilistic simulations and the system overgeneration avoided (calculated by simulation of the dispatching services market);

B5.b higher RES integration, defined by calculating the reduction in local congestion by means of static load flow simulations;

B6 avoided investment costs in further network infrastructures due to mandatory needings (e.g. to respect some law constraints)

B7 change in ancillary services provision costs, positive if there is a decrease;

Benefits classes Bx.a and Bx.b are mutually exclusive.

For specific intervention also the following benefits classes can be introduced, if needed:

B13 change in the resiliency of the System related to extreme events and further with respect to what accounted by B3; it's positive if there is an increase

B16 avoided operational costs in further network infrastructures due to mandatory needing (e.g. to respect some law constraints)

B18 change in the negative externalities due to CO_2 emissions, further than the ones already accounted for in B1 by means of CO_2 price; it is positive if there is a reduction

B19 change in negative impacts of non-greenhouse pollutant emissions; it is positive if there is a reduction.

B20 anticipation of the fruition of the benefits due to the implementation of more environmental-friendly technical approaches that result in speeding up the authorization process;

B21 Visual Amenity Preservation/Restoration

8.5 Other Impacts

The following classes of impacts are quantified within the CBA without monetizing them:

I21 increase in interconnection or transfer capacity, in MW

I22 change in land occupation by transmission infrastructures, in km

I23 change in occupation of areas of natural or biodiversity interest by transmission infrastructures, in km

I24 change in occupation of areas of social or landscape interest by transmission infrastructures, in km

Furthermore, also the following classes could be quantified in the CBA, even if not monetized in order to avoid double counting.

I5 increase in RES integration, defined by calculating the change in overgeneration by means of market simulations

I8.g change in CO_2 emissions calculated by day-ahead market simulations

I8.d change in CO_2 emissions calculated by ancillary services market simulations

I13 increase in system resiliency, with respect to extreme events, when it is not possible to determine it in a financial way

8.6 Cost Estimation Criteria

The methodology for estimation and update of the investment costs is based on what is prescribed in article 11 of attachment A of the Italian National Regulation Authority deliberation 627/2016 [20].

It is applied to all standard investments of the National Development Plan, but not to "special investments", due to the intrinsic innovative aspects that require dedicated investigation on the costs. Furthermore, this methodology is not applicable also to those interventions that are not standardisable.

The estimation of considered costs is divided into Operational (OPEX) and Capital (CAPEX) costs.

8.6.1 CAPEX

For each intervention considered, the investment cost $CAPEX_i$ is the sum of the investment costs of each construction project $CAPEX_{cp}$ that is included in the intervention and of the compensation costs CC_i due to local laws and regulation[1]:

$$CAPEX_i = \sum_{cp \in i} CAPEX_{cp} + CC_i;$$

$$CAPEX_{cp} = SC_{cp}\left(1 + CF_{cp}\right) + CPC_{cp} + DC_{cp}$$

where:

DC_{cp} is the cost for the demolition of existing structures

CPC_{cp} is the capitalized personnel cost

CF_{cp} is a contingency factor used to keep into account the economic impact of possible unexpected events

SC_{cp} is the standard cost of the construction project cp, given by

$$SC_{cp} = BC_{cp}(1 + \sum K_{n,cp})$$

where:

[1] Two classes of compensation costs can be considered: urban regeneration and environmental regeneration

$K_{n,cp}$ are incremental factors that used to keep into account all the exogenous variables that may impact the costs

K_1 localization and environmental or landscape conditioning

K_2 bureaucratic aspects

K_3 innovation and technical aspect influence

K_4 land acquisition and administrative controversies

K_5 procurement issues

K_6 secondary authorization and construction site implementation issues

K_7 impact of the replanning of the investment in order to have it available earlier and be able to anticipate its benefits

BC_{cp} is the base cost of the construction project cp, given by

$$BC_{cp} = \sum_{e \in cp} (D_e \cdot UC_e)$$

where:

D_e is the size of each element e of the construction project; examples of elements are lines, ground cables, power stations: each of them is represented by a "reference size" RS_e with a corresponding "specific unit price" UP_e;

UC_e are the specific unit costs of each element of the construction project, given by

$$UC_e = \sum(RS_e \cdot UP_e) + OC_e$$

where the other costs OC_e keep into account feedings, prescriptions compliance, tests, professional services and so on.

8.6.2 OPEX

Operational costs (OPEX) are defined by construction project typology based on yearly historical data of similar existing projects. They are indicated as specific operational cost per line length or per stations; furthermore, they do not include extraordinary costs or fault costs. OPEX are calculated as follows:

$$OPEX_{y,cp} = \sum_{e \in cp} SO_{y,e} \cdot D_e$$

where $SO_{y,e}$ is the yearly specific OPEX for the element e of the construction project cp.

8.7 Evaluation indexes and underlying hypotheses

Once benefits and costs have been calculated, the following economic indexes can be defined:

IUS System Utility Service, that is the ration between the actualized benefits and the actualized costs

VAN Net Present Value, that is the difference between actualized benefits and actualized costs (this indicator is calculated with benefits and costs actualized both to the year of preparation of the Development Plan and to the first year of cash flow).

The indicators above are usually calculated taking into account benefits from B1 to B7; if it is possible to monetize also benefits B13, B18, B19, B20 and B21, two values are given for each indicator: one calculated considering benefits B1 to B7 only and the other considering all the monetized benefits.

It is also possible to define uncertainty margins for the indicators if uncertainty is present on benefits and/or costs.

For the definition of these indexes, the following hypotheses are considered:

- real discount rate: 4%.
- investment expected life: 25 years.
- no residual value after 25 years.

CAPEX is conventionally referred to the year of commissioning of the infrastructure. Possible contributes in capital account are netted.

OPEX are conventionally considered for a period of 25 years, starting from the year after the infrastructure's commissioning and include possible contributes in capital account.

However, for the sake of transparency, contributes in capital count are explicitly indicated along with IUS and VAN values; IUS and VAN calculated without contributes in capital count are also indicated as a note to the text.

9 Annex IV: Network planning at e-Distribuzione

Development and preparation of investment plans on the distribution network aimed at satisfying the needs of:

- Connection of passive customers and / or producers
- Adaptation to the load evolution, safety, technological renewal, failures management
- Quality of Service Improvement, Resilience
- Integration of renewables and new kind of uses of electrical energy

The investment planning process includes several sequential steps:

1. Analysis of the state of the network, with evidence of any critical issues:
   a. Faults
   b. Load flows
   c. Quality of Service
2. Choice and planning of interventions
   a. Electrical calculations
   b. Cartographic support
   c. Constraints
3. Estimation of economic needs and budget allocation
   a. Long-term and annual economic planning
   b. Budget revisions during the year
4. Project monitoring
   a. Projects and works progress
   b. Spending progress

9.1 Network analysis: Quality of Service

The Italian Regulatory Authority for Electricity Gas and Water (ARERA) has identified the territorial areas as an aggregate of municipalities by province having the following characteristics:

- High Concentration (AC): aggregate of municipalities in a province with a population number higher than 50.000
- Medium Concentration (MC): aggregate of municipalities in a province with a population of between 5.000 and 50.000
- Low concentration (BC): aggregate of municipalities in a province with a population of less than 5.000

For the defined concentration areas, the target levels have been set for the following indicators, referring to accidental interruptions:

- DIL - Long Interruptions Duration (interruptions lasting more than 3 min)
- NILB - Number of Short + Long Interruptions (short outages are between 1s and 3 min)

The following targets have been set by ARERA (see Table 9.1).

Table 9.1 Target for quality of service.

Concentration Area	Population N°	Target DIL	Target NILB
Low Concentration	< 5.000	68 min/client	4,3

			interruptions/client
Medium Concentration	5.000 – 50.000	45 min/client	2,25 interruptions/client
High Concentration	> 50.000	28 min/client	1,2 interruptions/client

ARERA has further introduced a bonus / penalty mechanism by setting the trend levels to be reached for each area, and for each year of regulation. From 2015 for the DIL the trends coincide with the Target Level.

9.1.1 Quality of Service – Interventions

To improve the quality of the service, the interventions on the network are:

1. **Structure:** The structural interventions aim to reduce the number of customers per MV line and the length of the lines, as well as the number of non-meshed branches

The following interventions enable the creation of new MV lines to redistribute the number of customers on the other MV lines that are believed to be overloaded

- New Primary Substations
- Additional HV/MV transformer in Primary Substation
- New Switching Substation*
- Branches Meshing

Creation of New secondary substation: this intervention enables creation of new LV lines to redistribute the number of customers on the other LV lines that are believed to be overloaded

2. **Component**: Component interventions aim at replacing obsolete or highly damaged AT or MT components. The following interventions are used to lower the network failure rate:
   - Primary or Switching Substation components replacement
   - Replacement of obsolete transformers
   - Installation / replacement of Petersen coils
   - Refurbishment of MV line obsolete or with high failure rate
   - Replacing bare conductors with cable
   - Refurbishment of Secondary Substations

3. **Remote control and automation:** The remote control interventions aim to select the faulty sections remotely by promptly repowering the customers underlying the healthy portions of the network. On the other hand, automation and advanced automation interventions, by selecting faulty sections in extremely short times (<1s), they reduce customers impacted by long and short interruptions to the only customers of the faulty trunk. Among these can be mentioned:
   - Intervention for the implementation of Smart Fault Selection on MV feeders
   - Installation of MV reclosers along MV lines
   - MV network remote control

- LV network remote control

9.2 Network analysis – Load and Faults

Load: load flow calculations are carried out with different loading and production scenarios, in order to assess the quality of the lines (in terms of current carrying capacity and voltage variations at the nodes) under the most extreme conditions of exploitation.

Faults: consulting data on faults (cause, start and end of event, duration, impact on customers, plants involved), relating to the entire national network, it allows to identify the most critical areas.

9.2.1 Load and Faults – Interventions

For the resolution of load problems, according to the cases, the typical remedial interventions foresee:

- Network structure changes
- Replacement of conductors with others of larger cross section
- New MT lines
- Upgrading or new construction of Primary Cabin or Secondary Cabin

For what regards the faults, the resolutive interventions foresee the replacement of the components obsolete or with a high failure rate.

9.3 Connections

Each connection request that impacts on the MV network requires a proper evaluation process, in order to asses those impacts and, possibly, approve the request.

The approval of the proposal by the network planning unit requires both the verification of any interference with other development projects and the adequacy checks of the network to the installed power by means of Load Flow calculations. If necessary, the network planning unit will subordinate the connection to works to upgrade the MV network or, in extreme cases, also the HV network.

10 Annex V: Overview of values for VOLL in Europe

The table below provides an overview of values for VOLL in Europe [2], with an indication of the methodology used. The methodologies are not always properly documented; hence no direct comparison of values is possible, nor does ENTSO-E endorse any of the values shown below.

Table 10.1 Overview of values for VOLL in Europe. Source: [2]

Country	**VOLL (€/kWh)**	**Date**	**Used in planning?**	**Method/reference**
Austria (E control)	WTP: Industry 13,2, Households, 5,3 Direct worth: Households: 73,5	2009	No	R&D for incentive regulation, Surveys using both WTP and Direct Worth
France (RTE)	26. Sectoral values for large industry, small industry, service sector, infrastructures, households &	2011	Yes (mean value)	CEER: surveys for transmission planning using both WTP, Direct Worth and case studies.
Great Britain	19,75	2012	No	Incentive regulation, initial value proposed by Ofgem
Ireland	Households: 68 Industry: 8 Mean: 40	2005	No	R&D, production function approach
Italy (AEEG)	10,8 (Households) 21,6 (Business)60 20 to 40 (according	2003/2017	No	Surveys for incentive regulation, using both WTP and Direct Worth (SINTEF)
Netherlands (Tennet)	Households 16,4 Industry: 6,0 Mean: 8,6	2003	No	R&D, production function approach
Norway (NVE)	Industry: 10,4 Service sector: 15,4 Agriculture: 2,2 Public sector: 2 Large industry: 2,1	2008	Yes (sectorial values)	Surveys for incentive regulation, using both WTP and Direct Worth (SINTEF)
Portugal (ERSE)	1,5	2011	Yes (mean value)	Portuguese Tariff Code
Spain	6,35	2008	No	R&D, production function approach
Sweden	Households 0,2 Agriculture 0,9 Public sector 26,6 Service sector 19,8 Industry 7,1	2006	No	R&D, WTP, conjoint analysis