# WP3

## Optimal Planning Tools for Transmission and Distribution Systems

# Specification of the Planning Tools

D3.1

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# Abbreviations and Acronyms

| ACRONYM / ABBREVIATION | Extensive form |
|---|---|
| AC | Alternating Current |
| AC OPF | Alternating Current Optimal Power Flow |
| ADMM | Alternating Direction Method of Multipliers |
| DC | Direct Current |
| DC OPF | Direct Current Optimal Power Flow |
| DER | Distributed Energy Resource |
| DSO | Distribution System Operator |
| EV | Electric Vehicle |
| ESS | Energy Storage System |
| IRR | Internal Rate of Return |
| LP | Linear Programming |
| MILP | Mixed Integer Linear Programming |
| NPC | Net Present Cost |
| RES | Renewable Energy Sources |
| ROI | Return On Investment |
| SC | Security-Constrained |
| TSO | Transmission System Operator |
| WP | Work Package |

# 1. Executive summary

The energy system is evolving to meet the target of net-zero carbon emissions. This involves both energy transition to low carbon and renewable energy source and increasing adoption of automation, regulation and data collection to enable flexible services. Thus, it imposes great technical and economic challenges for the operation and planning of future energy systems. The ATTEST project aims to solve some of those challenges by developing an open-source toolbox comprising a suite of innovative tools to support TSOs / DSOs synergic operation, optimal maintenance of assets and coordinated planning of both transmission and distribution systems for 2030 and beyond.

This document presents deliverable D3.1 "Specification of the planning tools", which provides a general description of the different tools that are being developed within WP3, namely:

- Task 3.1: Optimisation tool for distribution network planning
- Task 3.2: Optimisation tool for transmission network planning
- Task 3.3: Optimisation fool for planning TSO/DSO shared technologies.

A functional and a technical description is provided for every tool, as well as inputs and outputs, computational requirements and interactions with other tools within ATTEST. This information is meant to provide a high-level overview of the current (preliminary) versions of the different tools and their main data inputs and outputs. The specific characteristics of the final versions of the tools, including various examples, will be provided in the next deliverable.

# 2. Introduction

In D3.1, an adaptive transmission and distribution system planning tool that facilitates the social and economic development of different regions within the power system under analysis is being developed. The tool accounts for uncertainties associated with regions within the system that may evolve differently from the rest. In this context, the transmission system would not only be planned to meet security needs, but also to exploit the use of emerging smart technologies and markets for both DSO and TSO.

## 2.1. ATTEST project

The objective of the ATTEST project is to develop a modular open-source toolbox comprising a suite of innovative tools to support TSOs / DSOs synergic operation, optimal maintenance of assets and coordinated planning of both transmission and distribution systems for 2030 and beyond, considering technical, economic and environmental aspects.

## 2.2. Optimal design and planning tools for transmission and distribution systems (WP3)

The aim of WP3 in the ATTEST project is to develop new investment planning tools for electrical distribution and transmission networks that support (and benefit from) emerging DSO and TSO markets and technologies. The planning tools model the flexibility which is aggregated from smart multi-energy customers to trade services, including network supports, in the different markets. Unlike traditional congestion-driven network reinforcements, ATTEST framework for planning also considers the use of demand-side flexibility for new business cases to extract the maximum value from the trade of flexibility through the TSO/DSO interface, e.g., market and active network management services.

The main objectives to be achieved include:

- Development of a flexible distribution network planning optimisation tool capable of addressing the integration of demand-side flexibility and its use by smart customers to partake in different DSO and TSO markets (e.g., trade of ancillary services to support the system and non-asset-based solutions to defer network investments).
- To develop a transmission expansion planning optimisation tool that considers the use of flexibility from emerging bulk generation technologies (e.g., storage) in combination with support from the demand side.
- To develop sophisticated tools to optimise the location and size of smart grid technologies that can provide valuable services at both distribution and transmission levels.

## 2.3. Description of the tools

The tools presented in this document are optimisation tools that support the TSOs and DSOs in planning the transmission and distribution networks considering flexibility from the markets.

The proposed distribution network optimisation tool is developed based on the stochastic formulation (non-recombining scenario trees) combined with a simulation-based optimisation framework to produce adaptive path-dependent network reinforcement strategies. The framework involves the application of investment optimisation and simulation algorithms. The optimisation model will utilise a recursive algorithm to optimise investment alternatives through different inter-dependent future scenarios (e.g., demand growth, integration of low carbon technologies, etc.) and considering asset degradation (modelled with the indices developed in WP5). The outcomes are flexible, adaptive investment strategies that seamlessly allow the network to be customised, for example through staged investment in hybrid portfolios of asset and non-asset-based solutions, in response to uncertain future change. The robustness of the investment strategies will be validated with relevant operation tools (developed in WP4) in an uncertain context (e.g., selected futures and Monte Carlo simulation) in terms of different economic, e.g., net present cost (NPC) and internal rate of return (IRR), and risk analysis such as minimax regret, value at risk criteria.

The proposed transmission network planning tool uses a three-stage scenario-based stochastic optimisation formulation. The first stage is a screening model. The screening model is a low-resolution deterministic transmission network investment optimisation model, which captures the flexibility of smart customers (modelled using the energy hub approach developed in T2.5) to partake in different TSO and DSO market environments (taken from T2.4 and T2.6) while also meeting the boundary technical requirements of other networks (e.g., gas and district heating considered in T2.5). The outputs of the screening model are used to produce a reduced set of investment alternatives that will inform the investment optimisation model. At the second stage, an adaptive master investment model optimises the location and size of the new assets and non-asset-based solutions based on long-term (yearly) uncertainties and a simplified linear representation of system operation in the context of specific DSO and TSO market conditions (defined in T2.4). At the third stage, a fast stochastic operational model (bespoke model that captures the complexity of the tools developed in WP4) identifies worst-case conditions considering short-term (e.g., hourly) operational uncertainties linked to the long-term (e.g., yearly) scenarios and investments proposed by the master model. The outputs of the operational model are then used to update the planning mathematical model within the master model. The models are solved iteratively to produce adaptive network investment planning strategies that explicitly model impacts at the operational stage and take advantage of demand-side flexibility traded in the different markets. The available operational flexibility to provide transmission network support will also be affected by the conditions of the distribution network defined in T2.5 and T3.1.

The objective of the shared resource planning tool is to develop an optimal investment plan in energy storage systems that can simultaneously provide services to the transmission and distribution sides of the network. The tool will be developed from the perspective of a third-party investor, the energy storage owner, and the outcome is an adaptive investment plan in energy storage systems to be installed or upgraded at the boundary points between the transmission and distribution networks. The tool will receive as inputs the optimal reinforcement plans in distribution and transmission networks (from T3.1 and T3.2, respectively) while considering the TSO-DSO coordination mechanism selected for the ATTEST project, defined in T2.4. The tool will recur to distributed optimisation concepts to reflect the interests, preserve the data privacy of the several parties involved in the planning process, and keep the tractability of the planning problem. Furthermore, to accurately reflect the degradation of battery energy storage systems' health, an accurate degradation model will be considered in the planning process. To reflect the uncertainty associated with future scenarios, stochastic programming will be used. The proposed framework is based on two main stages. At the first stage, an assessment of the flexibility that the DSOs can provide, without jeopardizing the operation of their own network, is performed. At the second stage, the optimal investment plan in energy storage systems is determined, considering the flexibility boundaries determined at the first stage. The second stage consists of an iterative process, based on the alternating direction method of multipliers, that will produce the optimal investment plan in shared energy storage systems.

## 2.4. Structure of the report

The rest of the document is structured as follows:

- Section 3 performs the literature survey of the network planning in the transmission and distribution networks.
- Section 4 describes the adaptive distribution network planning tool.
- Section 5 presents the adaptive transmission network reinforcement planning.
- Section 6 presents the specification of the optimisation tool for planning TSO/DSO shared technologies.
- Section 7 concludes the deliverable.

# 3. Transmission and distribution network planning: Theoretical background and current practice

Before introducing the network planning tools, it is worth describing the background of power systems expansion and reinforcement planning and distinguishing the features of the planning tasks in transmission and distribution networks. It is also important to define the role of flexibility at the TSO/DSO interface from flexible distributed energy resources, demand-side response, and other technologies. There is extensive literature on power systems expansion planning, with the first mathematical algorithms being developed in the 1960s. Since then, numerous novel formulations and applications have been developed to enhance existing tools (e.g., improving accuracy) and address emerging conditions (e.g., integration of renewable energy sources). According to the Scopus database, at least 2.100 publications explicitly focus on transmission expansion planning, and about 900 studies are dedicated to planning problems in distribution networks.

This section covers the general background and current practice in expansion planning at both transmission and distribution levels. Then, the need for TSO-DSO interactions and ways of coordination in planning are discussed.

## 3.1. Transmission network planning

Network planning is an essential task that enables meeting the growing electricity demand and ensuring efficient and secure operation of power systems. This task is especially important for transmission networks that form the backbone of electrical grids. Transmission networks are characterized by high voltage levels, long-distance transmission, and high-capacity generators and consumers connected. Historically, these large-size networks were developed to transport a large amount of power over long distances. For example, power can be transported between remote generators (wind parks, hydropower plants, etc.) and cities. Thus, transmission networks cover a major part of some countries and continents. Due to the large size of the generators and loads connected to these systems, transmission networks are designed meshed to provide high service reliability through redundancy, i.e., there exist parallel lines and loops. Finally, transmission networks usually have a high level of controllability and observability, which enables TSOs to effectively operate networks while maintaining their stability. To perform the network planning process, TSOs rely on engineering experience and transmission planning tools.[1] As an input, these tools require information on power systems, such as network models, demand profiles, investment costs, etc. Then, a series of calculations is performed, e.g., system operation simulations, maximisation of reliability, minimisation of costs, etc. The output is provided in terms of an optimal combination of the predefined expansion decisions, for example, recommended new lines or reinforcements, investments in non-asset-based solutions.

Significant progress has been achieved in developing transmission planning tools, models, and algorithms [1]–[5]. However, despite the level of complexity and differences in the formulations and applications, existing planning models follow the same principles: to supply power demand efficiently while satisfying technical constraints and reliability criteria. In general, transmission network planning addresses the energy trilemma challenges. That is, the optimal plan should have a reasonable balance between energy security, energy affordability, and environmental sustainability. A common approach used to develop transmission planning models is mathematical programming (sometimes simply referred to as optimisation models). Existing optimisation models can be applied to minimise the

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[1] Additionally, TSOs have to meet regional electricity infrastructure development plans, such as Europe’s ten-year network development plans developed by ENTSO-E.

operating and investment costs of power systems or maximise social welfare. However, the computational costs of these tools and the ability to guarantee the optimality of solutions are affected by the types of equations and variables used in the problem formulations. For example, the inherent power transmission physics, when modelled in detail, can make these models complex, non-linear, and non-convex. Moreover, the problems become more computationally expensive and difficult to solve with the inclusion of binary decision variables (i.e., mixed-integer problems), such as the variables used to model investment decisions and unit commitment. Thus, transmission expansion planning is usually characterized as mixed-integer non-linear problems, which are in general hard to solve. To address this issue, there is significant work on simplifying the formulation of the planning problem (at the expense of reducing accuracy), without greatly compromising the accuracy of the models. For example, the relaxations and approximations of the power flow equations can be used to simplify the planning problem [6]. In this regard, the proposed transmission network planning tool divides the planning problem into three stages. The first two modelling stages, the screening and investment models, are based on the linearised DC OPF approximation. These linear formulations guarantee convergence of the planning model. Then, the nonlinear AC OPF model is introduced at the third stage to verify the feasibility of the transmission expansion plan.

However, transmission network planning tools have been challenged by recent changes in the power sector. First, the deregulation and liberalization of power systems made a significant impact on transmission expansion planning [7]. The emergence of electricity markets, new business models of generating companies and retailers, unbundling of TSOs and DSOs challenged traditional transmission planning practices. Thus, common centralized optimisation approaches have been augmented by decentralized optimisation and game-theoretic models. Second, a major impact on the planning tools has been made by the penetration of renewables and distributed energy resources. The new power units with less controllable and more intermittent energy production posed additional challenges to the planning, control, and operation of power systems. Therefore, the effectiveness of stochastic and robust optimisation has been widely acknowledged in transmission planning [8], [9]. Moreover, the distributed energy resources and active distribution networks bring an additional source of uncertainty that has to be incorporated in the planning models [10]. Considering the aforementioned challenges, the security of power supply and power system operation becomes the primary goal of transmission expansion planning. Within the planning models, security is often defined by the contingency analysis and the N-1 criterion, which means that a transmission plan must be robust against any single possible contingency [11]. The contingency analysis is based on SC OPF formulations involving multiple post-contingency states, which results in a challenging computationally hard problem [12].

The increasing amount of DER capacity connected to distribution networks made it possible to provide additional services for transmission networks. The value of such flexibility services provided by active distribution networks and the importance of TSO-DSO interactions have recently been acknowledged. However, the lack of coordination between TSO and DSO can result in contradictory actions at transmission and distribution levels that hamper the provision of flexibility. Therefore, several concepts have been developed to enable TSO-DSO coordination [13]–[19]. The flexibility market between TSO and DSO could provide new additional non-asset-based solutions for transmission network planning. In the simple form of coordination, DSO provides a range of flexible power available at the TSO-DSO interface. Then, TSO can request specific feasible power support from DSO. The developed transmission network planning tools enable information exchange between DSO and TSO to fully exploit the flexibility of active distribution networks and improve planning and operation at the transmission level.

The tools described in this report follow the best practices in transmission network planning and address the mentioned challenges by incorporating several modelling techniques and approaches. A three-stage scenario-based stochastic optimisation formulation is proposed to minimise the network reinforcement cost and the cost of operation. To minimise the computational burden, the tool decomposes the planning problem into the investment and operation models. It also utilizes a screening model to identify and pre-select potentially attractive candidate investments. To account for the flexibility services provided by DSO, the transmission network planning tool includes available flexible power support at the TSO-DSO interfaces. In view of uncertainties influencing the operation of transmission networks, a stochastic operational model is formulated to identify possible worst-case short-term conditions and related long-term scenarios. Finally, to meet the N-1 security of transmission network operation, the investment model is complemented with the SC AC OPF analysis that enables identifying network binding constraints with respect to possible contingencies.

## 3.2. Distribution network planning

As opposed to transmission networks, which transport power through great distances (e.g., from the location of bulk generation to the cities), the role of the distribution networks is to distribute the energy across an area (e.g., within a city). As a result, distribution networks are usually characterized by medium and low voltage levels[2], short-distance transmission, and extensive usage of underground cable distribution systems. It follows that distribution networks are small- and medium-size networks that cover certain districts or cities. However, distribution networks have a large number of smaller loads and distributed generators connected as well as low carbon technologies integrated such as electric vehicles and energy storage. Since investing in redundancy is less cost-effective due to the smaller size of the customers connected at any point of a system, distribution networks are generally radial or weakly meshed, i.e., there exist very few parallel lines and loops. The power flows have historically been mainly unidirectional. They are directed from energy sources towards consumers, whose consumption and demand growth are relatively predictable in aggregated terms. But, due to a large number of substations and feeders and the lack of sensors and communication systems, distribution networks usually have a low level of controllability and observability.

Even though the planning tasks for distribution and transmission networks follow the same planning principles, i.e., meeting the demand growth in the most economical, reliable, and safe manner possible, the distribution network planning evolved into a separate research direction that fully accounts for the features of distribution grids [20]. Traditional distribution network planning focused on the reinforcement of feeders, the expansion of substations, and the installation of new network assets. These planning tasks required straightforward optimisation models: demand forecast must be met timely subject to voltage constraints and congestion management. Moreover, the radial topology of distribution networks and unidirectional power flows enabled using simplified OPF equations for radial grids [21]. Similar to transmission planning, distribution network planning is inherently a mixed-integer non-linear problem [22], [23]. The objective functions of existing optimisation models usually minimise investment and operation costs, power losses, and the cost of flexibility services. The constraints comprise power flow equations, technical limits of distribution networks, and security criteria. To solve such optimisation problems, various methods have been adopted in the literature including deterministic and heuristic algorithms as well as relaxation and approximation techniques.

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[2] In some cases, high voltage networks can be a part of distribution networks that cover large areas. But, in general, distribution networks are built in the vicinity of consumers, which enables supplying them at medium and low voltage.

However, the rapid growth of distributed energy resources, distributed storage, development of demand response programs, and adoption of smart monitoring, information, and communication technologies provided additional capabilities for distribution networks. It is now widely recognized that active distribution networks can exploit flexible resources, which allows achieving optimal operational and planning solutions with significant cost savings [20], [24]. But, to achieve efficiency and flexibility improvement, distribution networks require intelligent control and coordination of large numbers of DERs and demand response providers. Therefore, the concepts of DER, EV, and prosumers aggregators as well as the virtual power plant concept have been developed to capture the controllability and flexibility of active distribution networks [25]–[27]. The uncertainties related to DERs pose additional challenges to distribution network planning. Modern active distribution networks use advanced communication technologies to control generation availability, energy storage, and bidirectional power flows, and perform demand-side management. Thus, incorporating uncertainties becomes essential for distribution network planning tools [10], [28]–[31].

The flexibility of active distribution networks can also be captured by ancillary services provided by DSO to TSO. Several concepts have been recently developed to propose TSO-DSO coordination schemes and flexibility markets [13]–[19]. The common practice of evaluating distribution network flexibility services lies in estimating active and reactive power capability ranges at the TSO-DSO interface. The early studies relied on Monte Carlo simulations to illustrate the availability and cost of the flexible active and reactive power provided by distribution networks [32]. Then, more advanced DSO flexibility range assessment techniques and probabilistic capability charts were developed [33]–[39]. The TSO-DSO coordination and flexibility services provision is usually considered from the DSO's point of view. That is, it is assumed that TSO could request a specific active/reactive power operation point or specific voltage level at the TSO-DSO interface. DSO, in its turn, needs to analyse the availability of its resources as well as the technical constraints and reply to this request. DSO is also in charge of arranging contracts with distributed generators and imposing bands on their reactive power provision. It has recently been demonstrated that flexibility provided by a distribution network can be compared to that desired by a transmission network to estimate the power support adequacy at the TSO-DSO interface [40].

The distribution network planning tool presented in this report comprises advanced modelling techniques for distribution expansion planning. Specifically, multi-stage stochastic optimisation models are used to enable exploiting the potential of flexibility resources. The information on the available flexible power at the TSO-DSO interface nodes is passed to the transmission network planning tool to further improve the planning efficiency and flexibility at the transmission level. The proposed distribution network planning tool is based on the stochastic formulation (non-recombining scenario trees) combined with a simulation-based optimisation framework to produce adaptive path-dependent network reinforcement strategies. The tool is straightforward for DSO to implement. One of the major challenges of network planning is the computation cost which could be expensive considering the potentially massive number of investments under uncertain future conditions. To tackle this challenge, the proposed distribution network planning tool adopts a recursive algorithm for optimisation. The recursive function considers a reduced search space by terminating all infeasible investment strategies. Thus, the computation time is minimised compared to a full exhaustive search.

## 3.3. Optimisation tool for planning TSO/DSO shared technologies

Electric power systems are currently experiencing a profound change, as increasing amounts of Renewable Energy Sources (RESs) displace conventional forms of generation. This development has gone hand-in-hand with an expanding share of power production taking place at the distribution level, the connection of new types of DERs – such as Energy Storage Systems (ESSs) and Electric Vehicles (EVs) –, and active consumers, who have started to actively participate in the market, either by taking on the role of producer-consumer ("prosumer") or by engaging in Demand Response (DR) programs. These trends are expected to continue and will require a profound revision of the way TSOs and DSOs interact with each other [41].

Traditionally, transmission and distribution systems have been independently managed by TSO and DSOs, respectively, based on oversimplified models regarding each other's network [18]. Demand has been supplied by large-scale generating units connected to the transmission level, thereby allowing distribution systems to be passively operated, based on a "fit-and-forget" approach. However, the increasing penetration of DERs has triggered the need for the coordination and interaction between transmission and distribution levels in order to take advantage of the potential benefits that these flexible resources can bring to the operation of the overall electric power system [42]. It is expected that the exploitation of these resources will enable the increasing penetration of RES at a lower cost for consumers, by reducing the need to procure services from conventional generation; reduction of the investment costs; and improvement of asset utilization [43] [44]. According to ENTSO-E, in a planning setting, such interactions require integrated approaches that recognize the growing interdependence of the transmission and distribution networks. Thus, planning approaches should jointly consider both system levels to find the most effective and efficient network solution and generation deployment. This requirement is particularly relevant when renewable-based generation is involved [41].

For high levels of renewable energy and active consumers' participation in the power system operation, the balancing task becomes more complicated. Effectively dealing with the uncertainty derived from these types of resources requires more flexibility [45]. Energy storage increases the flexibility of power systems and therefore their ability to deal with uncertainty, being recognized as a means to provide additional system security, reliability and flexibility to respond to changes that are difficult to accurately forecast [46]. The increasing uncertainty associated with network operation creates new opportunities for ESS integration at different levels of the electric power system [47]. Although ESSs are not new to power systems, as their role in providing energy arbitrage or contingency services has existed for decades, these consisted mainly of larger ESS units, such as hydro storage and compressed air storage, which are restricted, due to their specific geographical requirements. Smaller battery ESS units do not suffer from these limitations and have lower environmental and non-technical constraints [48]. However, although ESS technology is maturing and continuously reducing in cost, these still require a relatively high initial investment. Battery ESSs also have the advantage of being able to be quickly deployed in the network, and their capacity can be increased gradually [49] [50].

It is likely that many of these ESSs will be deployed by private investors, and therefore we should consider not only whether they can provide a social benefit in terms of reduced operational costs, but also whether they generate sufficient Return On Investment (ROI) [51]. To reduce the risk of stranded assets, these investments should be robust with respects to errors in the long-term evolution of the load and renewable generation capacity [46]. Furthermore, in the presence of a TSO-DSO coordination schemes, these ESSs should also provide services to both operators, that might present conflicting objectives, therefore increasing the complexity of the planning process of these types of assets.

### 3.3.1. Energy Storage System Technologies

There are a variety of battery ESS technologies with different characteristics such as lead-acid, sodium sulphur (NaS), lithium-ion (Li-ion), nickel-cadmium (NiCd), and vanadium redox (VR). A comprehensive comparison of battery ESS technologies for power system applications is presented in [52]. The capital cost of the battery ESS is normally composed of power rating cost and energy rating cost. Even though these are important factors when selecting the appropriate technology, they are not the only factors that must be considered. For example, lead-acid batteries have the lowest capital cost among other technologies, however, it may not be the best option for performing the applications that require frequent charging/discharging, such as load levelling and energy arbitrage, due to its low lifecycle and high maintenance cost [53]. Another important aspect to consider is the battery's energy capacity degradation. Energy storage capacity degradation is mainly caused by two factors: calendric ageing and cyclic ageing. The former occurs even if the ESS is not used and is affected by the battery cells temperature and voltage, while the latter results from using (cycling). The battery's capacity is greatly affected by the Depth of Discharge (DoD) and the number of cycles. Disregarding the ESS cyclic ageing in the expansion planning problem results in an inaccurate economical assessment of the ESS.

Different methods were proposed to estimate the battery ESS lifecycle. However, it is not uncommon for ESS manufacturers to provide the relationship between lifecycle and DoD. This information is normally presented in a curve as the one depicted in Figure 1. As the DoD increases, the ESS lifecycle decreases. Different ESS technologies have different lifecycle versus DoD relationships. In lead-acid batteries, for example, this relationship tends to exhibit an exponential form whereas in lithium-ion batteries, a linear relationship is normally observed [53].

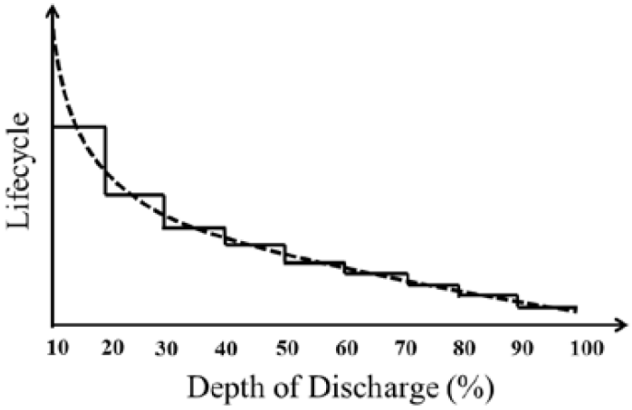


FIGURE 1 – ENERGY STORAGE SYSTEMS. LINEARIZATION OF THE LIFECYCLE AS A FUNCTION OF THE DEPTH OF DISCHARGE. SOURCE: [14].

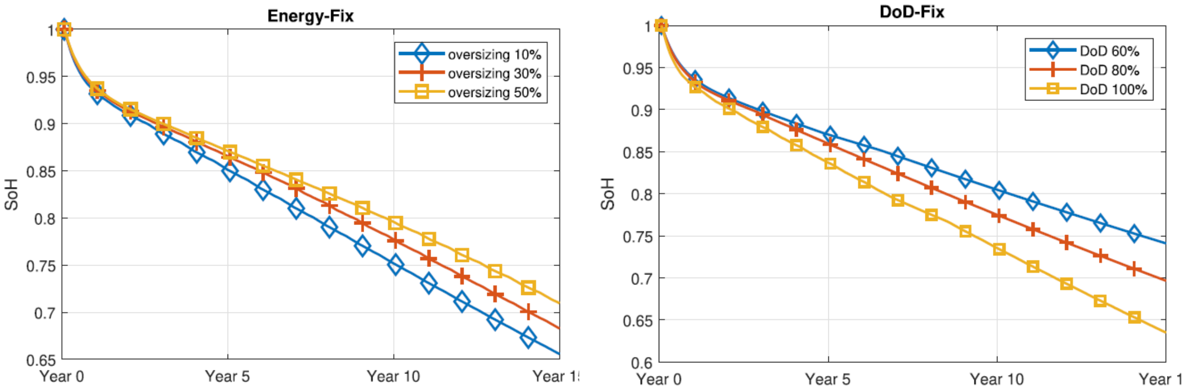
### 3.3.2. Energy Storage Planning

Works that consider the coordination between transmission and distribution networks have been previously reported. Primarily, these have been focused on the power flow [54], economic dispatch [55], unit commitment [56], expansion planning [45], contingency analysis [44] and flexibility estimation [57] problems. Many studies have addressed the optimal siting and sizing of battery ESSs for transmission and distribution networks separately [58] [59], but very few studies were published that consider both TSO and DSOs' interests in the planning of ESSs.

Motalleb [60] proposed a heuristic method to find the optimal location and capacity of a multi-purpose battery ESS, considering the interests of the transmission and distribution sides of the network. In the transmission side, in order to determine the optimal ESSs location, a sensitivity analysis is performed using complex-valued neural networks and a power flow routine. The ESSs' size is then determined by running a power flow routine and economic dispatch. The optimal size of the ESS from the distribution perspective is determined with the objective of providing grid services such as peak load shaving and load curve smoothing. The proposed method was applied to a real network model of a Hawaiian island. Mottaleb's work is one of the first proposals that consider the interest of transmission and distribution networks in ESS planning. However, it assumes the planner of the ESSs has full knowledge over the whole power system, which might be impracticable in practice, due to data privacy concerns [50]. Massuco [61] proposes a method to determine the optimal location, energy capacity, and power rating of distributed battery energy storage systems at multiple voltage levels for grid control and reserve provision. The method is based on a linearized formulation of the grid constraints of both the high voltage and medium voltage levels. Fundamental modelling aspects, such as transmission losses, effect of reactive power, On-Load Tap Changers (OLTC) at the MV/HV interface, ESS efficiency and models of conventional generators are also considered in the model. Similarly to Mottaleb's work, Massuco assumes full knowledge of the power system.

At the operational planning timeframe, Coppo addresses the ESS planning problem by considering an agreed and regulated power profile schedule at the primary substation [62]. The proposed method manages distributed ESSs with the objective of providing ancillary services to both the DSO (local regulation of distribution network and congestion management), and the TSO (control of the power profile at the primary substation). The methodology is based on a sliding time window approach, which evaluates the availability of each storage unit to provide ancillary services, assigns a scheduled profile, and corrects it during the real-time operation. At the operational timeframe, Pandžić proposed a method that considers the interaction between transmission and distribution systems. The proposed method is based on bilateral contracts, and day-ahead pricing is considered in order to maximise the powerplant profit considering a storage system, photovoltaic system, and a conventional generating unit. The conclusions highlight the importance of an accurate evaluation of the storage unit's energy and power ratings [63]

As an ESS project generally has a lifetime exceeding a decade, and batteries typically undergo severe capacity degradation throughout the project planning horizon, an accurate planning procedure should be used that considers the degradation of the battery's capacity. Battery ESS planning neglecting battery degradation may result in overestimated revenues and therefore reduce profitability. A precise battery ESS sizing method must consider that battery degradation is influenced by the ESS operation and specifications. Several methods are available for battery ESS sizing. Oversizing is the conventional method to handle battery degradation, by installing a higher battery capacity than the required one to deliver the intended amount of energy at the beginning of life. Figure 2 shows the degradation of the State of Health (SoH) of a 3.5 MWh battery, for different operation modes. Figure 2a shows the SoH degradation, considering several oversizing values for the capacity of the battery and a fixed energy value for the DoD; and Figure 2b shows the SoH curves considering several values for the DoD, expressed as a percentage of the energy capacity value [64].



a) Energy-fix case with various oversizing levels

b) DoD-fix case with various levels

Figure 2 – Battery capacity decrease curve considering the stress factor coefficients and mathematical modelling of [65]. Source: [64].

From Figure 2 it is possible to see that with oversizing levels of 10% and 30%, SoH values at year 15 are lower than 0.7 whereas a 50% oversizing level gives more than 0.7. It is also possible to see that high DoD reduces SoH significantly. If the DoD range is 100%, the SoH in the final year is computed as 0.64. Additionally, the gap between the SoH curves becomes larger as it approaches the final year. These figures indicate that battery capacity degradation is not a fixed parameter, but rather it is affected by various variables including storage sizes and DoD levels [64]. Although oversizing can be a feasible solution, ensuring sufficient energy capacity over such long periods may require installing excessive battery capacity upfront, which might substantially decrease the project's profitability. Another method is battery augmentation, in which new batteries are added to the ESS over time. Battery augmentation defers initial investments and can exploit future cost reductions in batteries. In [50], Shin explored an approach for optimal capacity determination of a battery ESS, considering the complex degradation of lithium-ion batteries. The proposed sizing algorithm iteratively evaluates the effect of battery ESS operation on battery degradation and estimates the cash flows of the power plant. In addition, the authors studied battery augmentation that adds the storage capacity in the base system to sustain the ESS capacity throughout the project planning horizon. Alharbi [49], proposes a decomposition-based approach to solve the problem of planning of ESS under uncertainty. The optimal decisions minimise the Net Present Value (NPV) of total expected costs over a multi-year horizon, taking into consideration the optimal battery ESS operation. A novel matrix representation of the battery energy capacity degradation is adopted, and the proposed approach is formulated as a two-stage Mixed Integer Linear Programming (MILP) problem, to ensure the convergence of the stochastic optimisation problem. The optimal ratings of the BESS are determined in the first stage, while the optimal installation year is determined in the second stage.

### 3.3.3. Co-Optimisation of Energy Storage Systems

Optimisation of ESSs, considering the interests of several parties, was considered in a number of published works, especially at the transmission level. Saber [48] proposed a new bi-level battery ESS planning framework that considers the preferences of an Independent System Operator (ISO) and independent investors simultaneously. In the proposed bi-level framework, the long-term total cost of the power system from the viewpoint of ISO is considered in the upper-level problem, and the short-term ESS scheduling from the viewpoint of independent investor is considered in the lower-level problem. In the lower-level problem, the behaviour of independent investors in the day-ahead electricity market is modelled in order to determine the charge/discharge schedule of the ESSs. To solve the addressed bi-level optimisation model, Benders dual decomposition technique has been employed.

Co-planning of energy storage and transmission systems is addressed in [66] [67] [68] [69] . Hu et al. [66] solve a MILP problem iteratively to determine the ESS investment size and locations by replacing part of the transmission investment while satisfying the same system requirement. Zhang et al. [67] propose a MILP model to determine the size and location of a single energy storage unit to minimise both the operation and investment costs taking line losses into account. Hedayati et al. [68] and Konstantelos et al. [69] propose multi-stage co-planning models to determine the location of a given size energy storage that minimises the one-time investment cost and the long-term operation cost. Hedayati et al. [68] uses a DCOPF based deterministic planning model, while a security-constrained OPF based stochastic planning framework is used in Konstantelos et al. [69]. Qiu [46] proposed a multi-stage co-planning tool for transmission and battery ESSs. The model determines both the size and the location of ESSs at each year of the horizon and is based on stochastic optimisation. The model also considers the degradation of the ESSs’ energy capacity and incorporates a unit commitment with reserve requirements.

### 3.3.4. Co-optimisation in the Power Systems Domain considering ESSs

Co-optimisation, or optimisation considering the interests of several parties/agents, has been applied to a number of other problems in the power systems domain, where ESSs are utilized. Iria [70] proposed a network-constrained bidding optimisation strategy to coordinate the participation of aggregators of prosumers in the day-ahead energy and secondary reserve markets. The bidding optimisation strategy consists of a decentralized approach, based on the Alternating Direction Method of Multipliers (ADMM), where aggregators negotiate with the DSO to obtain network-constrained energy and secondary reserve bids. The consumers and the grid negotiate on a receding horizon framework to obtain consensus solutions that satisfy the grid constraints under all operating conditions. This methodology also has the advantage of preserving the privacy of private consumers.

### 3.3.5. Final remarks

From the literature review, it can be seen that a lot of work has been published in the ESS planning field. However, so far, most of the published work is mainly focused on the optimal investment in ESS, either from an independent investor, DSO, or TSO perspective. Furthermore, only recently the models adopted for ESS planning have started to consider more complex topics, such as energy capacity degradation, the full AC formulation of the power flow equations, and uncertainty associated with future scenarios. It was also shown that the topic of transmission-distribution coordination is still in its infancy, and little to no research has been published on the joint-planning of ESSs or planning of ESSs in the presence of these types of coordination schemes. Furthermore, co-optimisation methods, that consider the interests of several parties were also addressed. Most of these papers are related to other types of problems related to the power systems field, but these arise as very interesting to solve optimisation problems that consider the interaction and coordination between TSO, DSOs, and third-party entities, such as ESS investors.

The proposed shared resource planning tool will consider the investment in TSO/DSO shared technologies, namely ESSs. The planning tool will be implemented from the perspective of a third-party entity, namely an investor in ESSs, with the objective of maximising the ROI, while providing services to both TSO and DSO, considering the coordination mechanism selected within the ATTEST project. The model will recur to stochastic optimisation to take into account the uncertainty associated with future scenarios. To decrease the computational burden, and maintain data privacy among the several actors, ADMM will be used.

# 4. Optimisation tool for distribution network planning (Task 3.1)

## 4.1. Functional description

The main objective of T3.1 is to develop a flexible and adaptive distribution expansion planning optimisation tool that considers the use of flexibility from the TSO/DSO market. The tool will capture challenges introduced by energy flows associated with the participation of smart customers in the TSO market, as well as the benefits offered by non-asset-based network support services traded in the DSO market. The latter may allow DSOs to support the TSO market and reduce both distribution and transmission networks' costs by pushing the distribution networks beyond traditional security limits while still meeting, and even improving, reliability standards thanks to the active use of post-contingency demand response, reliability support, and other advanced services that can be traded in a DSO market.

T3.1 aims to optimise network investment pathways (i.e., portfolios of investment decisions) for distribution networks across multiple future energy scenarios, i.e., 2030, 2040 and 2050. The investments are optimised considering both capital expenditure (asset build) and associated operation costs based on long-term uncertainties from future energy scenarios. The operation costs can be associated with generation, reliability and flexibility services procurement.

The developed T3.1 will be tested against several test cases which are developed in T2.3 as mentioned in Table 1. Further information about these test cases can be found in D2.3 (Test cases) of WP2 (Toolbox specification, support tools and test cases).

TABLE 1: DISTRIBUTION NETWORK TEST CASES DEVELOPED IN T3.1

| NETWORK TYPE | COUNTRY | NUMBER OF NETWORKS |
|---|---|---|
| Distribution | Portugal | 3 |
| | Spain | 3 |
| | UK | 3 |
| | Croatia | 3 |

## 4.2. Technical description

The developed tool in T3.1 is based on the concept that investment decisions, in addition to providing system benefits (e.g., higher capacity, reliability, etc.), also create options to pursue other benefits in the future (e.g., investing in network capacity to support emerging TSO/DSO flexibility). In order to consider these real options, the tool uses a stochastic formulation (non-recombining scenario trees) combined with a simulation-based optimisation framework to produce adaptive path-dependent network reinforcement strategies. A high-level description of the optimisation tool for distribution network planning is presented in Figure 3. As shown in the figure, to apply the tool, it is first necessary to collect generation, demand and network information as well as a portfolio of candidate reinforcement options (e.g., line and substation reinforcements and demand-side flexibility). As the tool uses a simulation-based optimisation approach (recursive function), the tool has to be initialized with a model of the initial conditions of the networks, before any reinforcements are done. Afterwards, a recursive function is used to simulate different investment alternatives across a path-dependent scenario tree depicting uncertainty (e.g., demand growth). Finally, the results, which are yearly recommended interventions across different scenarios (taken from the decision tree) are presented.

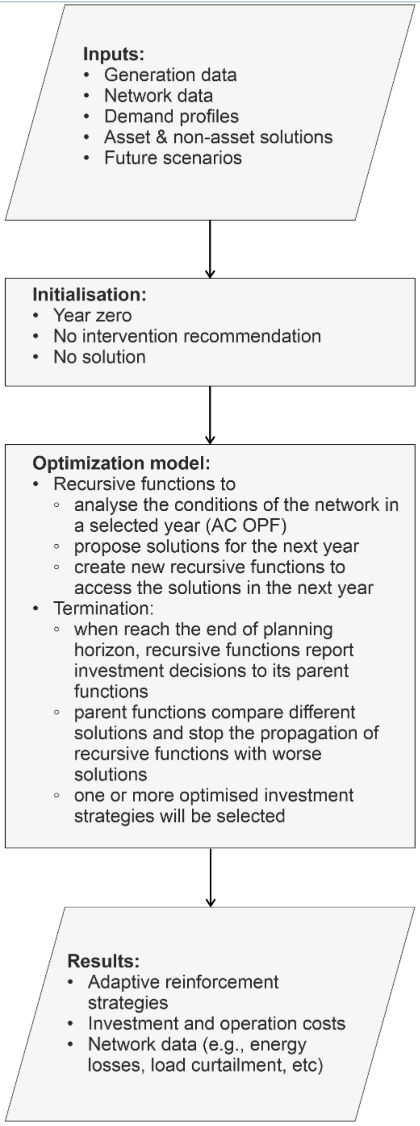


FIGURE 3: FLOWCHART OF THE METHODOLOGY FOR THE T3.1

### 4.2.1. Input data

The input data taken by the model includes generation data, demand profiles, a portfolio of network reinforcement options (including asset and non-asset solutions) and multiple future scenarios developed as a nonrecombining scenario tree. The generation, demand and network data must represent the characteristics of the network under consideration. Furthermore, the network reinforcement solutions considered in the study should also align with the practices of the relevant DSO. For example, some network companies keep in stock specific assets to reinforce their networks (e.g., cables with specific sizes and characteristics) and may have some regulation in place dictating the use of flexibility (e.g., a limited number of calls per year for the flexibility provided by customers).

### 4.2.2. Initialization

At the initialization stage, the initial conditions of the network and the recursive function are set. To be more specific, to initialize the recursive function, the year of study is set to zero (current year) with no recommendation of investments and no additional solutions (conditions of the current year). With the initial settings, the optimisation model utilises a recursive algorithm to optimise investment alternatives through different inter-dependent future scenarios (e.g., demand growth, integration of low carbon technologies, etc.) and considering asset degradation (modelled with the indices developed in WP5).

### 4.2.3. Optimisation model

The optimisation model uses a recursive function to select network reinforcement options across multiple years and scenarios (i.e., taken from the scenario tree). For this purpose, the recursive function emulates a branch-and-bound approach where (i) the function analyses the conditions of the network in a selected year, (ii) proposes network reinforcement solutions for the next year and (iii) creates a copy of itself (additional recursive functions) to assess the solutions in the next year. The new recursive functions then continue analysing future years and solutions (branch) and will stop propagating (bound) if the network conditions become unfeasible. Once a recursive function reaches the end of the planning lifetime, it will report its findings (investment strategy across multiple years) to its parent functions which can then compare different solutions (from other recursive functions), stop the propagation of recursive functions that offer worse solutions (another component of the bound process) and, ultimately, select one or more optimised investment strategies.

Based on the above, the optimisation model is developed based on three stages. The first stage is network modelling for a single year with AC OPF to analyse the network feasibility, power losses and corresponding costs. The network feasibility is decided by statutory voltage, thermal and security limits. The second stage is the recursions of identifying available investments and the potential combinations among them. The investments include both traditional asset-based solutions, i.e., distribution line reinforcements and substation (or transformer) reinforcement; and new non-asset-based solutions, i.e., the flexibility services from TSO/DSO market. The third stage indicates that when the end of the planning horizon is reached (e.g., typically 45 years for UK distribution networks [71]), the recursions will be terminated.

The outcomes of the planning tool are flexible, adaptive investment strategies that seamlessly allow the network to be customised, for example through staged investment in hybrid portfolios of asset and non-asset-based solutions, in response to uncertain future change. The robustness of the investment strategies will be validated with relevant operation tools (developed in WP4) based on criteria and approaches used in practice and recommended by literature to address uncertainty (e.g., selected future energy scenarios), as well as economic (e.g., NPC and IRR) and risk factors (e.g., minimax regret and existing network asset risk metrics).

The tool optimises investment decisions in consideration of an objective function, such as the minimisation of NPC in the UK [72]. The objective function is calculated across a scenario tree and can be assessed in terms of the expected value or in terms of a conditional value. Using the NPC defined by the UK regulator as an example, the objective function consists of the following terms:

- NPC associated with economic cost:
    - Capital costs that are expensed immediately
    - Depreciated capital costs
- NPC associated with social cost:
    - Cost associated with power losses
    - Cost associated with reliability

The tool can consider a wide range of investment options, currently, three types of investments are considered, namely:

- Distribution line extension or reinforcement
- Substation reinforcement
- Procurements of flexibility services, e.g., demand-side flexibility

The developed tool considers the following sets of constraints:

- Investment budget
- Active and reactive nodal power balance equations
- Generators active and reactive power limits
- Flexibility service active and reactive power limits, and maximum number of calls per period
- Full AC power flow equations
- Capacity constraints of distribution network lines
- Voltage magnitude and angle limits
- Load curtailment limit

Accordingly, the following decision variables are considered in each uncertainty scenario, time period, and operation state:

- Network investment decisions
- Generation dispatch
- Flexibility procurement
- Load curtailment

## 4.3. Input and output requirements

### 4.3.1. Input data

The general input data sets required by the T3.1 are:

- Distribution network models (developed in T2.3) that include data of distribution networks, e.g., buses, branches, generation and demand. An example of data for a Portugal transmission network is shown in Annex 1.
- Flexibility service data from TSO/DSO market (developed in T2.4 and T2.6) includes the maximum upwards and downward flexibility services. An example of flexibility data template is shown in Annex 2.
- Future energy scenarios (developed in T2.3) for 2030, 2040 and 2050.
- Catalogue of asset-based and non-asset-based solutions, e.g., portfolio of power lines and the cost of upgrading or installing a transmission line. In practice, this information would be provided by a DNO. In this work, online catalogues will be used.

An example of input data format can be found in the annex. Note that the planning tool is still under development, therefore, current formats of data may change in the future to facilitate data exchanging within the ATTEST project. The technical output data from the T3.1 is shown in Table 2.

TABLE 2: INPUTS FOR THE T3.1

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Generation data | Generation capacities | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Generation unit cost | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | €<br>€/MW, €/MVAr | MATPOWER |
| Network data | Bus data | - | - | MATPOWER |
| | Branch data | - | Ω | MATPOWER |
| Demand data | Demand profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Demand curtailment cost | - | €<br>€/MW, €/MVAr | MATPOWER |
| Asset-solutions | Unit cost for upgrading distribution lines | - | €<br>€ | MATPOWER/txt /json |
| | Unit cost for installing new distribution lines | - | € | MATPOWER/txt /json |
| | Unit cost for installing new transformers | - | € | MATPOWER/txt /json |
| Non-asset solutions | Flexibility service profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Flexibility service cost | - | €/MW, €/MVAr | MATPOWER |

### 4.3.2. Output data

The general output data from the T3.1 is:

- An adaptive investment planning strategy for the distribution network.
- Expected investment cost and operation cost.
- Energy losses and load curtailment, ultimately, the load curtailment is expected to be zero.

The technical output data from the T3.1 is shown in Table 3.

TABLE 3: OUTPUTS OF THE T3.1

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Investment decisions | Distribution line reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | txt |
| | New distribution line construction | Recommended investment planning horizon, e.g., throughout 20 years | - | txt |
| | Transformer reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | txt |

| | | | | |
|---|---|---|---|---|
| Costs (net present value*) | Investment cost | - | € | txt |
| | Generation cost | - | € | txt |
| | Penalty cost | - | € | txt |
| | Flexibility service cost | - | € | txt |

*Other metrics such as capital and operational expenditure (CAPEX and OPEX) will be included.

## 4.4. Computational requirements

A Python-based software will be developed to read, formulate mathematically, solve and store results of the transmission and/or distribution expansion planning problem. Python has been selected over other languages based on its simplicity, compatibility with other platforms, the option to use object-oriented functionalities, and a large number of well-established libraries (more than 137000 available libraries) and that it is an open-source programming language. Although Python can be installed just by downloading the official release on its website, it is more convenient to use a well-established package management tool such as Anaconda and therefore we intend to use it in this project. The main advantages of Anaconda are:

1) It allows installing different versions of Python on what is called “environments”, which allows testing Python code in different versions of Python if needed.
2) It could be difficult for non-experienced users to install Python libraries when they do not have administrative rights in their laptops/desktops but Anaconda solves this problem seamlessly by allowing the installation of libraries only using user rights.
3) Users of different libraries in Python tend to experience incompatibilities between versions of libraries, i.e. library “A” might require to use a specific version of library “B” but users tend to download the latest version of any library and sometimes (quite often) this action causes errors with library “A”. Anaconda solves the problem of versioning and compatibility of libraries providing a ready-to-use package to the user.

A Julia implementation of the operation model for transmission systems will be used. The implementation had been developed using the modelling language for mathematical optimisation JuMP. Solving the resulting mathematical problem needs to be solved in order to get useful information that any user can use at a later stage for the analysis of the optimised power system. Ipopt has been selected as the solution package for the specific problems that we are solving. Other solution packages or software might be used to solved additional or more specific mathematical models that could be developed during the lifetime of the WP.

During the development of the code different versions from different developers will be produced and this situation can cause a problem of incompatibility of software between developers if a proper versioning and testing structure is not in place. Git is then used as the versioning software in order to solve this well-known problem in software development. For automatic testing and continuous delivery we could potentially use web services such as GitLab or GitHub, or depending on resources availability an in-home testing desktop/server could be used.

Interacting effectively with users and providing the information that they require in an easy but effective way is the main goal of any software. The software developed in WP3 will use a CLI (command line interface) to interact with the user. The user will be able to run the software and visualize results through the CLI, which will require a single line of execution (by default) to solve a problem.

A summary of the software requirements is as follows:

- Anaconda
- Git
- Julia
- C++ compiler (Visual Studio or gcc)

Libraries and/or third-party software for Julia and Python that are mandatory:

- JuMP
- Ipopt
- Pyomo

License

- Open source

## 4.5. Interactions with other tools

The interactions between the distribution network planning tool (T3.1) and the other tools developed within the ATTEST project are shown in Figure 4.

- T2.3 provides the test cases and T2.4 provides flexibility service data from TSO/DSO market used by T3.1. The test cases are data of distribution networks, e.g., buses, branches, generation and demand. An example of data for a Portugal transmission network is shown in Annex 1. Flexibility service data from TSO/DSO market includes the maximum upwards and downward flexibility services. An example of flexibility data template is shown in Annex 2.
- T3.1 identifies the distribution network investment planning strategy and input the information to T3.3 which develops an optimisation tool for planning TSO/DSO shared technologies. The investment planning strategy includes upgrading installing a distribution line, upgrading substations and investment on flexibility services.
- T4.2 identifies available capacity in the distribution network for T3.1.
- T5.3 provides optimal asset management plans to T3.1. In WP5 it will be estimated the time in which the recommended thresholds for the life of assets will be exceeded. This will be defined depending on the type of assets. This can be valuable in WP3 to fine-tune the life of assets, to compute more accurately their net present value. WP5 will provide file assessment indexes, that will be used in WP3 to determine the required preventive or corrective maintenance cost, and to guide the replacement of assets.
- The tools developed in WP3 will be tested and validated in WP7 (T7.2), also providing assessment criteria (T7.3)

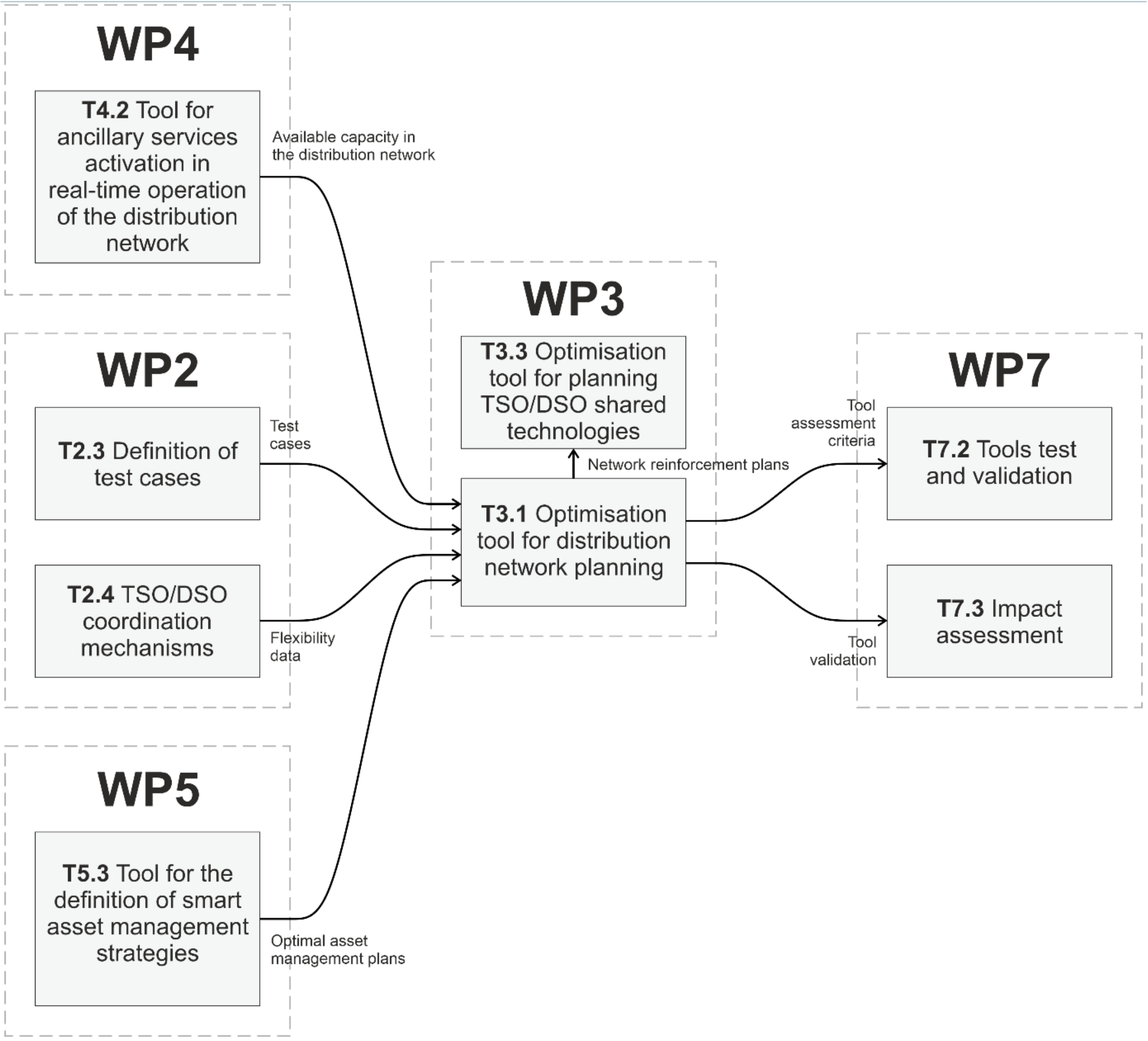


FIGURE 4: INTERACTIONS OF TOOL T3.1 WITH OTHER ATTEST TOOLS

# 5. Optimisation tool for transmission network planning (Task 3.2)

## 5.1. Functional description

The main objective of T3.2 is to develop a flexible transmission expansion planning optimisation tool that considers the use of flexibility from emerging bulk generation technologies (e.g., storage) in combination with support from the demand side.

T3.2 aims to optimise network investment pathways for transmission networks across multiple future energy scenarios, i.e., 2020, 2030, 2040 and 2050. The investments are optimised considering both capital expenditure (asset build) and associated operation costs based on long-term uncertainties from future energy scenarios. The operation costs can be associated with generation, reliability and flexibility services procurement.

The developed planning tool for the transmission network is adaptive and it facilitates the development of different regions. The tool accounts for uncertainties associated with regions of the network that may evolve differently from the rest. Long-term uncertainty is considered by identifying the optimal location and size of new asset-based and non-asset-based solutions while short-term uncertainty is captured by considering worst-case scenarios (i.e., N-1 condition) in hourly operations.

The developed T3.2 will be tested against several test cases which are developed in T2.3 as mentioned in Table 4. Further information about these test cases can be found in D2.3 (Test cases) of WP2 (Toolbox specification, support tools and test cases).

TABLE 4: TRANSMISSION NETWORK TEST CASES DEVELOPED IN T3.2

| NETWORK TYPE | COUNTRY | NUMBER OF NETWORKS |
|---|---|---|
| Transmission | Portugal | 7 |
| | UK | 1 |
| | Croatia | 3 |

## 5.2. Technical description

The three-stage framework combines a screening model, a MILP and a detailed network operation model. A high-level representation of the methodology is shown in Figure 5.

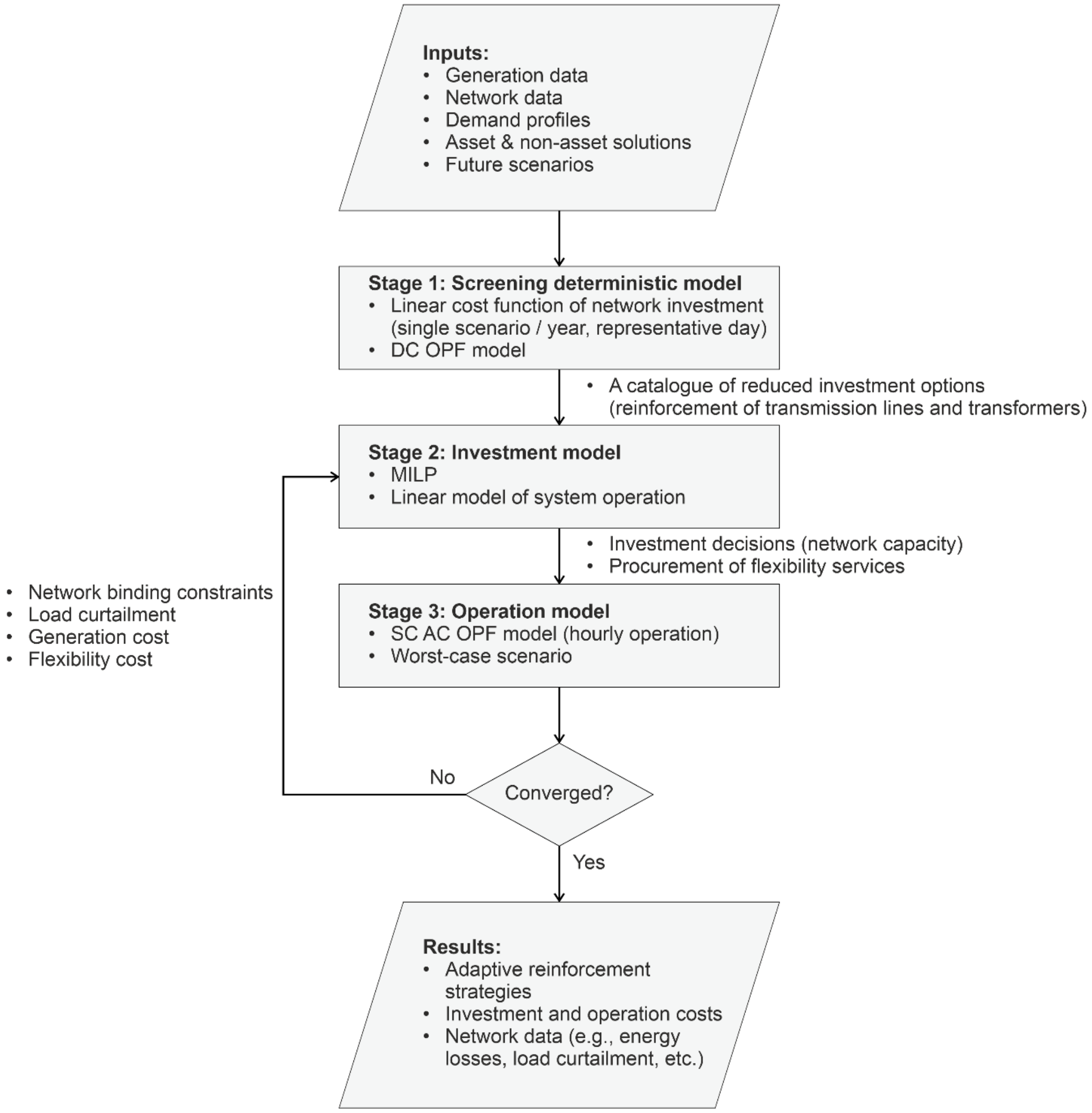


FIGURE 5: FLOWCHART OF THE METHODOLOGY FOR THE T3.2

The input data are generation data, demand profiles, asset and non-asset solutions and future scenarios. The screening model is a simplified version of the planning model, e.g., a DC OPF model with a linear cost function for network investments which is only applied to specific conditions (e.g., single year for a single scenario). The screening model is applied to different scenarios to identify which network components would normally be reinforced, i.e., transmission lines and transformers. In order to capture the uncertainties of the future, two different energy scenarios are considered for each year of 2030, 2040 and 2050, i.e., one optimistic scenario with more electrification and renewable integration (known as “Two degrees” in the UK or “Active Economy” in the ATTEST project) and one pessimistic scenario which is more conservative in electrification and renewable integration (known as “Slow progression” in the UK or “Steady progression” in the ATTEST project). The screening model captures uncertainties by considering these different future energy scenarios. The relevant options are then selected to create a catalogue and inputs to the investment model.

The investment model determines the initial investment strategies based on the catalogue provided by the screening model. The catalogue is the starting condition for the investment model and the path dependency is captured by starting with different conditions that are identified by the screening approach.

The determined information (i.e., investment decisions and procurement of flexibility services) is then passed to the operation network model which runs SC AC OPF analysis. The results of SC AC OPF from the operation model are used to create the network binding constraints and calculate the operation costs. This information is then fed back to the investment model. The process is then iteratively repeated between stage 2 and stage 3 until the results converge to a point where network violations are averted or cannot be further alleviated while maintaining a minimum total cost.

### 5.2.1. Stage 1: screening model:

Optimising a planning strategy for transmission networks can be computationally expensive considering the potentially massive number of investments available, some of which can become attractive under uncertain future conditions. To mitigate this issue, the proposed planning tool utilizes a screening model to identify and pre-select potentially attractive candidate investments. A screening stage is added because of the massive number of potential investments which is computationally expensive. The candidate investments would have to be pre-selected through the screening approach. The screening model is a deterministic process that runs different scenarios while neglecting the dependencies among decisions. The dependency means the effects of previous decisions.

The screening model is a simplified version of the planning model, e.g., a DC OPF model with a linear cost function for network investments which is only applied to specific conditions (e.g., single year). The model is applied to different scenarios to identify which network components would normally be reinforced. The relevant options are then selected to create a catalogue, i.e., reinforcements of transmission lines and transformers.

The objective function used by the screening model is the minimisation of costs. To be more specific, the objective function consists of the following terms:

- Costs associated with asset-based reinforcements:
  - Transmission line reinforcements
  - Transformer reinforcements
- Costs associated with network operation:
  - Generation cost
  - Penalty cost for load curtailment

The screening model places focus on asset-based network solutions. The specific solutions that are currently considered by the tool include:

- Upgrading and installing transmission lines
- Installing transformers

The developed tool considers the following sets of constraints:

- Active and reactive nodal power balance equations
- Generators active and reactive power limits
- DC power flow equations
- Capacity constraints of transmission network lines

The screening model outputs a reduced catalogue of investment options for the transmission network, including the investment decisions on transformers and transmission lines. The detailed output data from stage 1 is presented in Annex 3.

### 5.2.2. Stage 2: investment model

Stage 2 is the investment model which uses MILP for scenario-based stochastic optimisation formulation. The aim of stage 2 is to develop investment strategies that optimise the location and size of the new asset and non-asset-based solutions based on long-term uncertainties from future scenarios.

In the stage 2 of the proposed transmission network planning tool, the objective function consists of the following terms:

- Asset-based reinforcement costs
    - Transmission line reinforcement costs s
    - Transformer reinforcement costs s
- Non-asset-based reinforcement costs s
    - Procurement costs of flexibility services
- Network operation cost
    - Generation cost
    - Penalty cost

The investment decisions considered for transmission network planning are:

- Upgrading and installing transmission lines
- Installing transformers
- Procurements of flexibility services

The developed tool considers the following sets of constraints:

- Investment budget
- Active and reactive nodal power balance equations
- Flexibility service active and reactive power limits
- Capacity constraints of transmission network lines
- Linear approximation of network constraint violations
- Non-anticipatively constraints

Accordingly, the following decision variables are considered in each scenario, time period, and operation state:

- Network investment decisions

The investment model outputs investment decisions for the transmission network and the corresponding costs for the reinforcements. The detailed output data from stage 2 is presented in Annex 3.

### 5.2.3. Stage 3: Operation model

Stage 3 is an operation model which performs hourly operations and identifies the worst-case conditions considering the proposed investment decisions from stage 2. Stage 3 runs SC AC OPF and the results are used to update the network binding constraints in stage 2. The process is then iteratively repeated between stage 2 and stage 3 until the results converge to a point where network violations are averted or cannot be further alleviated.

In the stage 3 of the proposed transmission network planning tool, the objective function consists of the following terms:

- Non-asset-based solutions
    - Procurement of flexibility services
- Network operation cost
    - Generation cost
    - Penalty cost

The investments considered for distribution network planning are:

- Upgrading and installing transmission lines
- Installing transformers
- Procurements of flexibility services

The developed tool considers the following sets of constraints:

- Generators active and reactive power limits
- Active and reactive nodal power balance equations
- Flexibility service active and reactive power limits
- Full SC AC OPF power flow equations
- Capacity constraints of transmission network lines
- Voltage magnitude and angle limits
- Load curtailment limit

Accordingly, the following decision variables are considered in each uncertainty scenario, time period, and operation state:

- Parameters to update binding constraints
- Generation dispatch
- Load curtailment
- Flexibility procurement

The operation model updates the parameters required for binding constraints in stage 2. It also outputs the costs for operation and penalty. The detailed output data from stage 3 is presented in Annex 3.

## 5.3. Input and output requirements

### 5.3.1. Input data

The general input data sets required by the T3.2 is:

- Test cases (developed in T2.3) that includes data of transmission networks, e.g., buses, branches, generation and demand.
- Flexibility service data from TSO/DSO market (developed in T2.4 and T2.6) includes the maximum upwards and downward flexibility services.
- Future energy scenarios (developed in T2.3) for 2030, 2040 and 2050.

- Costs for asset-based and non-asset-based solutions, e.g., the cost of upgrading or installing a transmission line.

The technical input data for the T3.2 is shown in Table 5. A detailed input data required for each stage of T3.2 is shown in Annex 3.

TABLE 5: INPUTS FOR THE T3.2

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Generation data | Generation capacities | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Generation unit cost | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | €/MW, €/MVAr | MATPOWER |
| Network data | Bus data | - | | MATPOWER |
| | Branch data | - | Ω | MATPOWER |
| Demand data | Demand profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Demand curtailment cost | - | €/MW, €/MVAr | MATPOWER |
| Asset-solutions | Unit cost for upgrading transmission lines | - | € | MATPOWER/txt /json |
| | Unit cost for installing new transmission lines (per type) | - | € | MATPOWER/txt /json |
| | Unit cost for installing new transformers (per type) | - | € | MATPOWER/txt /json |
| Non-asset solutions | Flexibility service profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Flexibility service cost | - | €/MW, €/MVAr | MATPOWER |

### 5.3.2. Output data

The general output data from the T3.2 is:

- An adaptive investment planning strategy for the transmission network.
- Expected investment cost and operation cost.
- Energy losses and load curtailment, ultimately, the load curtailment is expected to be zero.

The technical output data from the T3.2 is shown in Table 6. A detailed output data from each stage of T3.2 is shown in Annex 3.

TABLE 6: OUTPUTS OF THE T3.2

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Investment decisions | Transmission line reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | txt |
| | New transmission line construction | Recommended investment planning horizon, e.g., throughout 20 years | - | txt |
| | Transformer reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | txt |
| Costs (net present value) | Investment cost | - | € | txt |
| | Generation cost | - | € | txt |
| | Penalty cost | - | € | txt |
| | Flexibility service cost | - | € | txt |

## 5.4. Computational requirements

A Python-based software will be developed to read, formulate mathematically, solve and store results of the transmission expansion planning problem. Python has been selected over other languages based on its simplicity, compatibility with other platforms, object-oriented characteristics, and a large number of well-established libraries (more than 137000 available libraries) and that it is an open-source programming language. Although Python can be installed just by downloading the official release on its website, it is more convenient to use a well-established package management tool such as Anaconda and therefore we intend to use it in this project. The main advantages of Anaconda are:

1) It allows installing different versions of Python on what is called “environments”, which allows testing Python code in different versions of Python if needed.
2) It could be difficult for non-experienced users to install Python libraries when they do not have administrative rights in their laptops/desktops but Anaconda solves this problem seamlessly by allowing the installation of libraries only using user rights.
3) Users of different libraries in Python tend to experience incompatibilities between versions of libraries, i.e. library “A” might require to use a specific version of library “B” but users tend to download the latest version of any library and sometimes (quite often) this action causes errors with library “A”. Anaconda solves the problem of versioning and compatibility of libraries providing a ready-to-use package to the user.

A Julia implementation of the operation model for transmission systems will be used. The implementation had been developed using the modelling language for mathematical optimisation JuMP. Solving the resulting mathematical problem needs to be solved in order to get useful information that any user can use at a later stage for the analysis of the optimised power system. Ipopt has been selected as the solution package for the specific problems that we are solving. Other solution packages or software might be used to solve additional or more specific mathematical models that could be developed during the lifetime of the WP.

During the development of the code different versions from different developers will be produced and this situation can cause a problem of incompatibility of software between developers if a proper versioning and testing structure are not in place. Git is then used as the versioning software in order to solve this well-known problem in software development.

Interacting effectively with users and providing the information that they require in an easy but effective way is the main goal of any software. The software developed in WP3 will use a CLI (command line interface) to interact with the user. The user will be able to run the software and visualize results through the CLI, which will require a single line of execution (by default) to solve a problem.

A summary of the software requirements is as follows:

- Anaconda
- Git
- Julia
- C++ compiler (Visual Studio or gcc)

Libraries and/or third-party software for Julia and Python that are mandatory:

- JuMP
- Ipopt
- Pyomo

License

- Open-source

## 5.5. Interactions with other tools

The interactions between the transmission network planning tool (T3.2) and the other tools developed within the ATTEST project are shown in Figure 6.

- T2.3 provides the test cases and T2.4 provides flexibility service data used by T3.2. The test cases are data of transmission networks, e.g., buses, branches, generation and demand. Flexibility service data from TSO/DSO market includes the maximum upwards and downward flexibility services. An example of flexibility data template is shown in Annex 2.

- T3.2 identifies the transmission network reinforcement plans and input the information to T3.3 which develops an optimisation tool for planning TSO/DSO shared technologies. The investment planning strategy includes upgrading installing a transmission line, installing a transformer and investment on flexibility services.

- T4.5 identifies available capacity in the transmission network and T4.4 provides the operation model used by the stage 3 of T3.2.

- T5.3 defines optimal asset management plans for T3.2. In WP5 it will be estimated the time in which the recommended thresholds for the life of assets will be exceeded. This will be defined depending on the type of assets. This will be used in WP3 to fine-tune the life of assets, in order to compute more accurately their net present value. WP5 will provide file assessment indexes, that will be used in WP3 to determine the required preventive or corrective maintenance cost, and to guide the replacement of assets.

- T3.2 will be tested and validated in T7.2. T3.2 will also provide assessment criteria to T7.3.

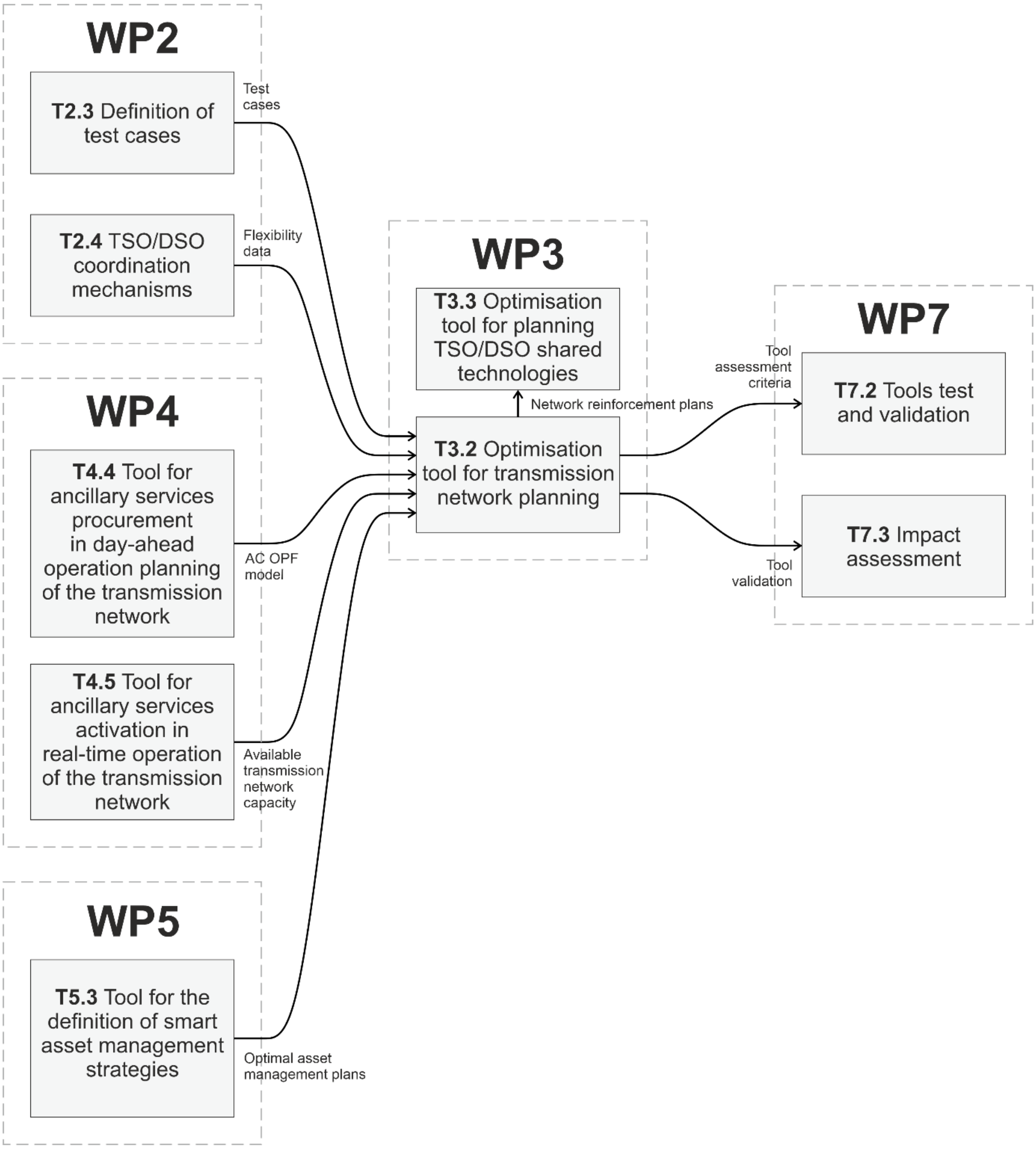


FIGURE 6: INTERACTIONS OF TOOL T3.2 WITH OTHER ATTEST TOOLS

# 6. Optimisation tool for planning TSO/DSO shared technologies (Task 3.3)

## 6.1. Functional Description

The main objective of T3.3 is to develop a novel optimisation tool for placing and sizing battery ESSs at the connection points between the transmission and distribution networks, which may be shared and managed in coordination by the TSO and DSOs. Similarly to the aforementioned tools (T3.1 and T3.2), the tool will consider the challenges introduced by energy flows associated with active consumers and renewable generation, such as the uncertainty associated with these power flows, and the different interests from the several parties involved in the planning of these types of assets.

This tool will incorporate the TSO/DSO coordination mechanisms defined in T2.4 for planning. The optimisation tool will be developed from the perspective of a third-party entity, namely an ESS investor, with the objective of evaluating and assessing the attractiveness of ESS investment in TSO/DSO regulated markets. The potential impact derived from the ancillary services will also be assessed, from the TSO and DSOs' perspectives.

The developed planning tool for shared ESS technologies will consider critical aspects related to battery ESS planning, such as battery degradation and battery augmentation strategies. In this regard, long-term and short-term uncertainties will be adequately addressed through stochastic programming techniques.

## 6.2. Technical Description

The tool developed in T3.3 is based on stochastic programming, with the objective of producing an optimal investment plan in battery ESSs that can be jointly operated by TSO and DSOs, from the perspective of a third-party investor. A high-level representation of the proposed methodology is shown in Figure 7.

The input data are topological data, expected costs and specifications associated with ESS technologies, demand and renewable generation profiles, investments in asset and non-asset solutions and future scenarios. At the first stage, the tool will receive as inputs the investment plans in the distribution and transmission network, forecasted renewable energy production and flexibility profiles provided by non-asset-based solutions (such as active consumers). The optimisation model will be developed based on ADMM, with the objective of reflecting the different objectives from the several parties involved in the shared ESS planning process, as well as maintaining data privacy.

The optimisation process is based on two main stages. To reflect the TSO-DSO coordination mechanism selected for ATTEST, described in D2.4, initially an assessment of the flexibility available at the distribution level is performed. This assessment intends to disclose the flexibility that can be provided by the distribution network at the connection point with the transmission network, that does not jeopardize (i.e., leads to technical constraints) the operation of the distribution network. This assessment is performed taking into account the networks' technical limits, such as voltage limits, line thermal limits, distributed generation limits, and limits of other network assets (such as transformer with on-load regulation, capacitor banks and distributed ESSs), and the flexibility limits provided by active consumers. After this initial assessment, an iterative process, based on ADMM is performed, that intends to determine the optimal investment plan in ESSs, taking into account the objectives of the different parties involved. Namely, the TSO will want to minimise the costs associated with the operation of the transmission network, the DSO will want to minimise the costs associated with the operation of the distribution network, while taking into account its duty as a flexibility provider to the TSO, and the ESS investor will want to maximise the profit derived from providing ancillary services to TSO and DSOs, taking into account the investment and operational costs associated with ESS.

The outcome of the proposed tool is an investment plan in ESSs, namely power rating and battery capacity, to be installed each year at the connection points between the transmission and distribution networks.

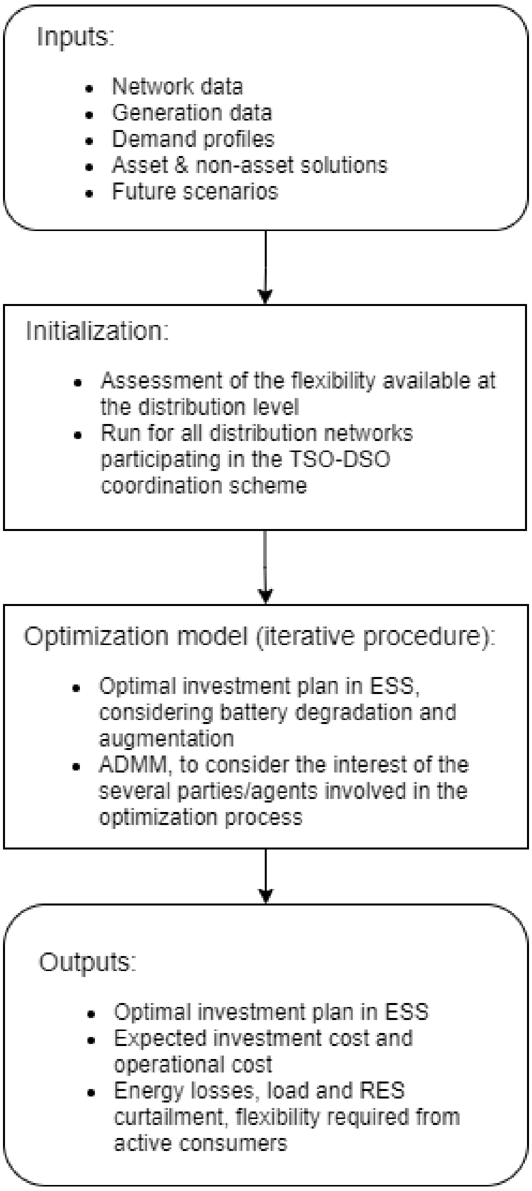
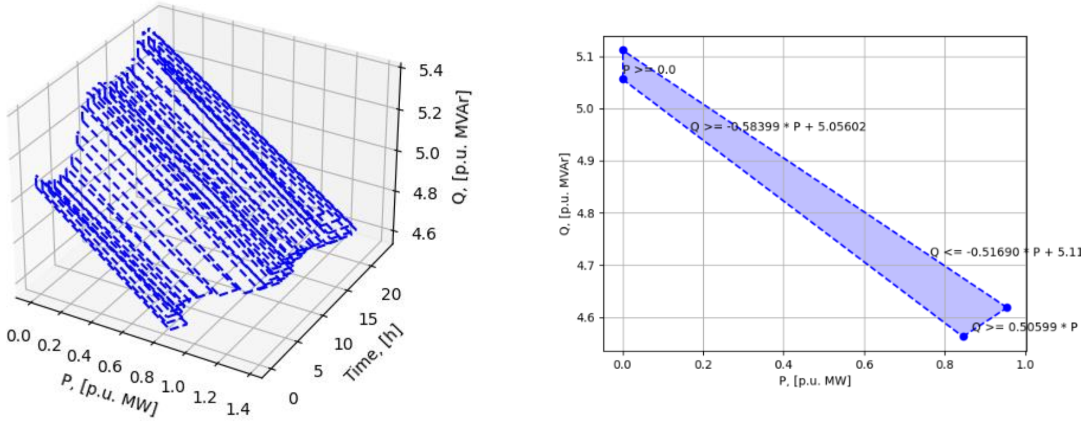


FIGURE 7: TSO-DSO SHARED RESOURCE PLANNING TOOL. FLOWCHART OF THE METHODOLOGY.

### 6.2.1. Initialization

The objective of the distribution network flexibility assessment tool is to determine the flexibility that a distribution network can supply at the point of connection with the transmission network, that can be exploited by the TSO for network management purposes. This procedure is executed for every

Distribution System Operators that participate in the TSO/DSO coordination scheme i.e., that can supply flexibility to the TSO. The procedure consists of the determination of a flexibility map, which represents all of the possible operation points possible at the distribution level, without causing constraints in the distribution network. The output of this tool is a flexibility area, that demonstrates the active and reactive power flow possible at the connection point between the transmission and distribution networks. Figure 8 shows an illustration of a possible flexibility map, the output of the first stage of the TSO/DSO shared resource planning tool. The flexibility map is represented through a set of equations that are a function of the active and reactive power flow at the connection point with the distribution network. This allows the inclusion of these equations as constraints in the second stage of the TSO-DSO shared resource planning procedure.



a) Multi-period flexibility map, for a 24-hour optimisation period.

b) Detail of the flexibility map, for the first instant of the optimisation period.

FIGURE 8: TSO-DSO SHARED RESOURCE PLANNING TOOL. EXAMPLE OUTPUT OF THE FIRST STAGE. REPRESENTATION OF THE FLEXIBILITY AVAILABLE IN A DISTRIBUTION NETWORK.

### 6.2.2. Optimisation model

The objective of the second stage is to determine the optimal investment plan in ESS, that will be shared by TSO and DSOs to manage their networks. To reflect the coordination scheme adopted in ATTEST, the flexibility maps determined at the first stage of the shared resource planning tool enter as input in the second stage, essentially restricting the active and reactive power consumption at each connection point with the distribution networks participating in the TSO-DSO coordination scheme.

The optimisation problem must consider the objectives of the several parties (agents) involved in the planning procedure. From the TSO perspective, the objective of the optimisation problem is to minimise the NPC related to the operation of the transmission system, considering the flexibility provided by DSOs and the flexibility provided by the ESSs installed at the boundary points with the distribution systems, that will be shared with the respective DSOs. The TSO must consider the restrictions related to the management of the transmission system. From the DSO perspective, the objective is to minimise the NPC related to the operation on the distribution network, considering the flexibility requirements from the TSO, and the ESS installed at the boundary between the transmission and distribution systems. The DSO must consider the restrictions associated with the management of the distribution system. From the investor in the ESS devices perspective, the objective is to maximise the NPV of the investment in ESS. This optimisation problem, where several parties with different objectives are involved, will be solved through ADMM. ADMM has the advantage of limiting the amount of information exchanged between the different parties involved in the optimisation process (essentially, only the desired active and reactive profiles will be exchanged), and also decomposing the larger optimisation problem, involving the full transmission and distribution systems, into smaller problems thus contributing to the tractability of the main problem.

## 6.3. Input and Output Requirements

### 6.3.1. General Inputs

The general input data for the planning tool is:

- Test cases (developed in T2.3) that includes data of transmission networks, e.g., buses, branches, generation and demand.
- Investment plans in transmission and distribution networks (developed in T3.1 and T3.2)
- Flexibility service data from TSO/DSO market (developed in T2.4 and T2.6) which includes the maximum upwards and downward flexibility services.
- Future energy scenarios (developed in T2.3) for 2030, 2040 and 2050.
- Costs for asset-based and non-asset-based solutions, e.g., ESS technology cost over the planning horizon, prices of ancillary services provided by the ESS.

### 6.3.2. General Outputs

The general output data from the planning tool is:

- An investment planning strategy for the shared TSO-DSO ESSs.
- Expected investment cost and operational cost.
- Energy losses, load and renewable generation curtailment, and flexibility required from active consumers.

### 6.3.3. Stage 1: Estimation of the flexibility available at the distribution level

#### *6.3.3.1. Input data*

TABLE 7: SHARED RESOURCE PLANNING (TASK 3.3). INPUTS FOR STAGE 1.

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Generation data | Generation capacities | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER, Excel |
| | Generation unit cost | Representative days (24 hours) for different scenarios | €/MW, €/MVAr | MATPOWER, Excel |

| | | | | |
|---|---|---|---|---|
| | | (weekday, weekend, summer and winter) | | |
| Network data (transmission and distribution) | Bus data | - | | MATPOWER |
| | Branch data | - | Ω | MATPOWER |
| Demand data | Demand profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER, Excel |
| | Load shedding cost | - | €/MW, €/MVAr | MATPOWER, Excel |
| Non-asset solutions | Flexibility service profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER, Excel |
| | Flexibility service cost | - | €/MW, €/MVAr | MATPOWER, Excel |

#### *6.3.3.2. Output data*

TABLE 8: SHARED RESOURCE PLANNING (TASK 3.3). OUTPUTS OF STAGE 1.

| DATA | TYPE | UNITS | FORMAT |
|---|---|---|---|
| Flexibility Map | Maximum flexibility available in the distribution network at the connection point with the transmission network for the planning period | MW, MVAr | Txt/Excel/json |

### 6.3.4. Stage 2: Co-Optimisation of Shared TSO-DSO resources

#### *6.3.4.1. Input data*

TABLE 9: SHARED RESOURCE PLANNING (TASK 3.3). INPUTS FOR STAGE 2.

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| **Generation data** | Generation capacities | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER, Excel |
| | Generation unit cost | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | €/MW, €/MVAr | MATPOWER, Excel |
| **Network data** | Bus data | - | | MATPOWER |
| | Branch data | - | Ω | MATPOWER |

| | | | | |
|---|---|---|---|---|
| **Demand data** | Demand profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Demand curtailment cost | - | €/MW, €/MVAr | MATPOWER |
| **Asset-solutions** | Unit cost for ESS rating | - | €/MWh | Txt/Excel |
| | Unit cost for ESS capacity | - | €/MVA | Txt/Excel |
| | Unit cost for upgrading ESS capacity | - | €/MWh | Txt/Excel |
| **Non-asset solutions** | Flexibility service profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER/Excel |
| | Flexibility service cost | - | €/MW, €/MVAr | MATPOWER/Excel |

#### *6.3.4.2. Output data*

TABLE 10: SHARED RESOURCE PLANNING (TASK 3.3). OUTPUTS OF THE PLANNING TOOL.

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Investment decisions | ESS installation plan | Recommended investment planning horizon, e.g., throughout 20 years | - | Txt/Excel |
| | ESS upgrade plan | Recommended investment planning horizon, e.g., throughout 20 years | - | Txt/Excel |
| Costs (net present value) | Investment cost | - | € | Txt/Excel |
| | Upgrade cost | - | € | Txt/Excel |

## 6.4. Computational Requirements

The planning tool will be developed in Python programming language and the optimisation problem will be formulated recurring to the optimisation modelling language Pyomo [73] [74], allowing the abstraction from the underlying solver to be used. Similarly to T3.1 and T3.2, the user is advised to install a package management tool, such as Anaconda.

During the development of the code different versions from different developers will be produced and this situation can cause a problem of incompatibility of software between developers if a proper versioning and testing structure are not in place. Git is then used as the versioning software in order to solve this well-known problem in software development.

Interacting effectively with users and providing the information that they require in an easy but effective way is the main goal of any software. The software developed in WP3 will use a CLI (command line interface) to interact with the user. The user will be able to run the software and visualize results through the CLI, which will require a single line of execution (by default) to solve a problem.

A summary of the software requirements is as follows:

- Anaconda
- Git

- C++ compiler (Visual Studio or gcc)

Libraries and/or third-party software for Python:

- Pyomo
- Third-party solver, compatible with Pyomo (e.g., IpOpt [75])

License

- Open-source

## 6.5. Interactions with Other Tools

The interactions between the shared resource planning tool (T3.3) and the other tools developed within the ATTEST project are shown in Figure 9.

- WP2--Toolbox specification, support tools and test cases:
  - WP2 provides the test cases (T2.3) and the TSO/DSO coordination mechanism (T2.4) used by T3.3.
- WP3--Optimal design and planning tools for transmission and distribution systems:
  - T3.1 identifies the distribution network reinforcement plans.
  - T3.2 identifies the transmission network reinforcement plans.
- WP7--Demonstration and impact assessment:
  - The tools developed in WP3 will be tested and validated in WP7 (T7.2), also providing assessment criteria (T7.3).

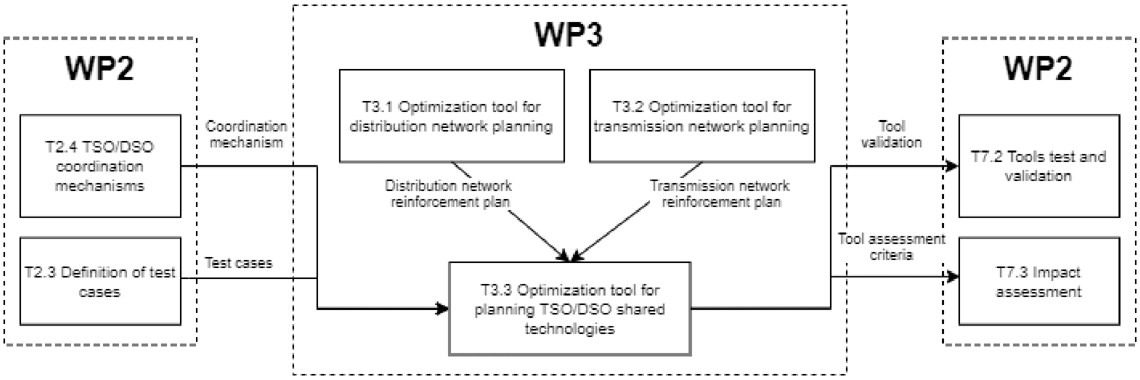


FIGURE 9: TSO-DSO SHARED RESOURCE PLANNING TOOL. INTERACTIONS AMONG THE TOOLS.

# 7. Concluding remarks

This deliverable presents the specifications of the planning tools to be used in the ATTEST project that support the TSOs and DSOs in planning the transmission and distribution networks considering flexibility from the markets. It includes the current state-of-art of the network planning tools, a description of the functions and techniques, data inputs and outputs, computational requirements and interactions of other tools within the project. The specification of the tools will allow ATTEST partners to understand the functions of the tools, and also will facilitate the cooperation among tools developed in different WPs.

The proposed distribution network optimisation tool is developed based on the stochastic formulation (non-recombining scenario trees) combined with a simulation-based optimisation framework to produce adaptive path-dependent network reinforcement strategies. The proposed transmission network planning tool uses a three-stage scenario-based stochastic optimisation formulation. The shared resource planning tool uses distributed optimisation techniques, namely ADMM, and stochastic programming to identify the optimal investment strategy in ESS to be shared by TSO and DSOs under uncertain future scenarios. The detailed mathematic formulations are not included in this report as they are the focus of a dedicated final report when the development of the tools (D3.2 and D3.3) is finished.

The functions specified in this document will continuously be developed and enhanced during the project.

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# 9. Annex

## 9.1. Annex 1 | Examples for data inputs

The text of the case format is presented here with more detail (although truncated to save space). It can be read as a MATPOWER file. Note that the same format is used for both transmission and distribution networks.

```
function mpc = Transmission_Network_PT_2020
```

```
%% MATPOWER Case Format : Version 2
mpc.version = '2';
```

```
%%-----  Power Flow Data  -----%%
%% system MVA base
mpc.baseMVA = 100;
```

```
%% bus data
%   bus_i  type   Pd  Qd  Gs  Bs  area   Vm  Va  baseKV  zone   Vmax   Vmin
mpc.bus = [
   1   2   0.000   0.000   0   0   1   1   0   400 1   1.05    0.95    ;
   2   2   0.000   0.000   0   0   1   1   0   400 1   1.05    0.95    ;
   ...
   303 1   0.000   0.000   0   0   1   1   0   63  2   1.05    0.95    ;
   304 1   0.000   0.000   0   0   1   1   0   63  2   1.05    0.95    ;
];
```

```
%% generator data
%   bus Pg  Qg  Qmax    Qmin    Vg  mBase   status  Pmax    Pmin    Pc1 Pc2 Qc1min  Qc1max  Qc2min  Qc2max
ramp_agc    ramp_10 ramp_30 ramp_q  apf
mpc.gen = [
   1  253.567 -38.483 9999.000    -9999.000   1.0431  100.00  1   9999.000    -9999.000   0   0   0   0   0   0   0
0   0   0   0   ;
...
0   0   0   0   0   0   0   0   0   0   0   ;
   22  0.000   0.000   23.063  -23.063 1.0307  62.10   0   57.658  0.000   0   0   0   0   0   0   0   0   0   0   0   ;
   30  31.000  1.512   15.500  -12.400 1.0349  34.66   1   31.000  15.500  0   0   0   0   0   0   0   0   0   0   0   ;
...
0   0   0   0   0   0   0   0   0   0   0   ;
   293 0.000   0.000   10.000  -10.000 1.0122  26.93   0   25.000  0.000   0   0   0   0   0   0   0   0   0   0   0   ;
];
```

```
%% gen tags
% Generation Technology Type:
%  CWS (Connection with Spain),
%  FOG (Fossil Gas),
%  FHC (Fossil Hard Coal),
%  HWR (Hydro Water Reservoir),
%  HPS (Hydro Pumped Storage),
```

```
% HRP (Hydro Run-of-river and poundage),
% SH1 (Small Hydro - P ≤ 10 MW),
% SH3 (Small Hydro - 10 MW < P ≤ 30 MW),
% PVP (Photovoltaic power plant),
% WON (Wind onshore),
% WOF (Wind offshore),
% MAR (Marine),
% OTH (Other thermal, such as geothermal, biomass, biogas, Municipal solid waste and CHP renewable and
non-renewable)
%   genType
mpc.gen_tags = {
   'CWS'; 'CWS'; 'CWS'; 'CWS'; 'CWS'; 'CWS'; 'CWS'; 'PVP'; 'PVP'; 'HWR'; 'HWR'; 'HRP'; 'HRP'; 'HRP';
'WON'; 'SH3'; 'HRP'; 'HRP'; 'OTH'; 'WON'; 'SH1'; 'PVP'; 'OTH'; 'OTH'; 'OTH'; 'PVP'; 'OTH'; 'SH1'; 'PVP';
'OTH'; 'WON'; 'SH1'; 'SH3'; 'PVP'; 'HPS'; 'HPS';
 ...
'HRP'; 'HRP'; 'HRP'; 'HRP'; 'HRP'; 'HRP'; 'HRP'; 'HRP'; 'FOG'; 'FOG'; 'FOG'; 'FOG'; 'HRP'; 'HPS'; 'HPS';
'HPS'; 'HPS'; 'HPS'; 'HPS'; 'HPS'; 'HPS'; 'HPS'; 'HWR'; 'HWR'; 'FHC'; 'FHC'; 'FHC'; 'FHC'; 'FHC'; 'FOG';
'FOG'; 'FOG'; 'FOG'; 'FOG'; 'FOG'; 'OTH'; 'WON'; 'WON'; 'WON'; 'WON'; 'OTH'; 'WON'; 'WON'; 'WON';
'WON'; 'WON'; 'WON'; 'WON'; 'HRP'; 'HRP'; 'HRP'; 'WOF';
};
```

```
%% branch data
% If the 'step_size', 'actTap', 'minTap', 'maxTap' and 'normalTap' fields are equal to "-1", it means that the
transformer does not have tap changing capability
% If the length is equal to "0", it means that the correspondent branch represents a transformer
%  fbus   tbus   r  x  b  rateA (summer)  rateB (spring)  rateC (winter)  tap ratio  shift angle    status  angmin
angmax  step_size  actTap  minTap  maxTap  normalTap  length (km)
mpc.branch = [
   8   24  0.02945 0.09879 0.03302 91  123 130 0   0   0   -360    360 0   0   0   0   0   54.0    ;
   8   176 0.02007 0.06867 0.02205 96  104 104 0   0   1   -360    360 0   ...
   101 158 0.00153 0.09299 0.00000 170 170 170 1.008333333 0   1   -360    360 0.0042  15  1   25  13  0   ;
   103 160 0.00153 0.09299 0.00000 170 170 170 1.012500000 0   1   -360    360 0.0042  16  1   25  13  0   ;
   103 160 0.00151 0.09267 0.00000 170 170 170 1.012500000 0   1   -360    360 0.0042  16  1   25  13  0   ;
   105 164 0.00182 0.08988 0.00000 170 170 170 1.016666667 0   1   -360    360 0.0042  17  1   25  13  0   ;
   105 164 0.00184 0.09109 0.00000 170 170 170 1.016666667 0   1   -360    360 0.0042  17  1   25  13  0   ;
];
```

```
end
```

## 9.2. Annex 2 | Examples for flexibility data format

The text of the flexibility data format is presented here with more detail (although truncated to save space). It can be read as a MATPOWER file.

```
function mpc = flexibility_data_UK_2020(mpc)

%% flexibility connection data
mpc.flex.flexbus = [
   2;      % bus number where flexibility services are available
   4;
];

%% flexibility profile mode
mpc.flex.flexprof = [
% Mode                                        % time interval:
%3 = representative business day for a season  %Fraction of an hour,
                                                                   e.g., 1 = 1h, 0.5 = 30 mins
            3          1;
];

%% Active upwards flexibility data
%   time (hourly)
mpc.flex.PFMax_UP = [
  % 1          2          3          ...   23          24               % hour
  0.439283     0.063231   0.930325   ...   0.934726    0.434099    ;    % bus 2
  0.871791     0.11562    0.456429   ...   0.561145    0.944855    ;    % bus 4
];

%% Active downwards flexibility data
%   time (hourly)
mpc.flex.PFMax_DN = [
  % 1          2          3          ...   23          24               % hour
  0.439283     0.063231   0.930325   ...   0.934726    0.434099    ;    % bus 2
  0.871791     0.11562    0.456429   ...   0.561145    0.944855    ;    % bus 4
];

%% Reactive upwards flexibility data
%   time (hourly)
mpc.flex.QFMax_UP = [
  % 1          2          3          ...   23          24               % hour
  0.439283     0.063231   0.930325   ...   0.934726    0.434099    ;    % bus 2
  0.871791     0.11562    0.456429   ...   0.561145    0.944855    ;    % bus 4
];

%% Reactive downwards flexibility data
%   time (hourly)
mpc.flex.QFMax_DN = [
  % 1          2          3          ...   23          24               % hour
```

```
  0.439283    0.063231    0.930325    ...    0.934726    0.434099    ;    % bus 2
  0.871791    0.11562     0.456429    ...    0.561145    0.944855    ;    % bus 4
];
```

```
%% Flexibility cost data
%   1   n   x1  y1  ... xn  yn
%   2   n   c(n-1)  ... c0
%   3   -   w1  w2  ... w24
%   4   -   ω

mpc.flex.flexcost = [

                                                  %COST_PF               %COST_QF
  %Model    %NCOST    %COST_PR    %COST_QR
                                                  %1    ...    24        %1    ...    24          %hour

     3        0          100          10          0.95   ...   0.68      0.13   ...   0.07    ;    %bus2

     4        0          100          10          0.58    ;                                        %bus4

];
```

```
end
```

## 9.3. Annex 3 | Data inputs and outputs for each stage of T3.2

The detailed technical input data for each stage of the T3.2 is shown in Table 11, Table 12 and Table 13.

Table 11: Inputs for stage 1 of T3.2

| Data | | Type | Units | Format |
|---|---|---|---|---|
| Generation data | Generation capacities | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Generation unit cost | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | €/MW, €/MVAr | MATPOWER |
| Network data | Bus data | - | | MATPOWER |
| | Branch data | - | Ω | MATPOWER |
| Demand data | Demand profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | | MATPOWER |
| | Demand curtailment cost | - | €/MW, €/MVAr | MATPOWER |
| Asset-solutions | Unit cost for upgrading transmission lines | - | € | MATPOWER/txt /json |
| | Unit cost for installing new transmission lines | - | € | MATPOWER/txt /json |
| | Unit cost for installing new transformers | - | € | MATPOWER/txt /json |
| Non-asset solutions | Flexibility service profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Flexibility service cost | - | €/MW, €/MVAr | MATPOWER |

Table 12: Inputs for stage 2 of T3.2

| Data | | Type | Units | Format |
|---|---|---|---|---|
| Generation data | Generation capacities | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Generation unit cost | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | €/MW, €/MVAr | MATPOWER |
| Network data | Bus data | - | | MATPOWER |
| | Branch data | - | Ω | MATPOWER |
| Demand data | Demand profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Demand curtailment cost | - | €/MW, €/MVAr | MATPOWER |
| Asset-solutions | Unit cost for upgrading transmission lines | - | € | MATPOWER/txt /json |

| | | | | |
|---|---|---|---|---|
| | Unit cost for installing new transmission lines | - | € | MATPOWER/txt /json |
| | Unit cost for installing new transformers | - | € | MATPOWER/txt /json |
| Non-asset solutions | Flexibility service profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Flexibility service cost | - | €/MW, €/MVAr | MATPOWER |
| Investment decisions | Transmission line reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | MATPOWER/txt /json |
| | Transformer reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | MATPOWER/txt /json |

TABLE 13: INPUTS FOR STAGE 3 OF T3.2

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Generation data | Generation capacities | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Generation unit cost | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | €/MW, €/MVAr | MATPOWER |
| Network data | Bus data | - | | MATPOWER |
| | Branch data | - | | MATPOWER |
| Demand data | Demand profiles | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, MVAr | MATPOWER |
| | Demand curtailment cost | - | €/MW, €/MVAr | MATPOWER |
| | Flexibility service cost | - | €/MW, €/MVAr | MATPOWER |
| Investment decisions | Transmission line reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | MATPOWER/txt /json |
| | New transmission line construction | Recommended investment planning horizon, e.g., throughout 20 years | - | MATPOWER/txt /json |
| | Transformer reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | MATPOWER/txt /json |

The detailed technical output data from each stage of the T3.2 is shown in Table 14, Table 15 and Table 16.

TABLE 14: OUTPUTS OF STAGE 1 OF T3.2

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Investment decisions | Transmission line reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | MW | MATPOWER/txt /json |
| | Transformer reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | MW | MATPOWER/txt /json |

TABLE 15: OUTPUTS OF STAGE 2 OF T3.2

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Investment decisions | Transmission line reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | MATPOWER/txt /json |
| | New transmission line construction | Recommended investment planning horizon, e.g., throughout 20 years | - | MATPOWER/txt /json |
| | Transformer reinforcement | Recommended investment planning horizon, e.g., throughout 20 years | - | MATPOWER/txt /json |
| Costs | Investment cost | - | € | MATPOWER/txt /json |
| | Generation cost | - | € | MATPOWER/txt /json |
| | Penalty cost | - | € | MATPOWER/txt /json |
| | Flexibility service cost | - | € | MATPOWER/txt /json |

TABLE 16: OUTPUTS OF STAGE 3 OF T3.2

| DATA | | TYPE | UNITS | FORMAT |
|---|---|---|---|---|
| Network | Parameters to update binding constraints | Single value for each iteration | - | HDF5 |
| Energy profile | Load curtailment | Representative days (24 hours) for different scenarios (weekday, weekend, summer and winter) | MW, €/MVAr | HDF5 |
| Demand data | Generation cost | - | € | HDF5 |
| | Flexibility service cost | - | € | HDF5 |