Deliverable 4.3 – B3
Grid Impact studies of electric vehicles

Future Distribution Network Planning Tools: Functional Specifications

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List of Abbreviations

ANM	Advanced Network Management
AVC	Automatic Voltage Control
BaU	Business as Usual
CBA	Cost-Benefit Analysis
CHP	Combined Heat and Power
CIC	Customer Interruption Cost
COC	Customer Outage Cost
COP	Coefficient of Performance
COPT	Capacity Outage Probability Table
DER	Distributed Energy Resource
DG	Distributed Generation
DLR	Dynamic Line Rating
DMS	Distribution Management System
DNO	Distribution Network Operator
DSM	Demand-Side Management
DSO	Distribution System Operator
DW	Dishwasher
EEGI	European Electricity Grid Initiative
EENS	Expected Energy Not Supplied
EHV	Extra-High Voltage
EV	Electric Vehicle
FBD	Fault Breaking Device
GD	Group Demand
GMT	Ground-Mounted Transformer
HP	Heat Pump
HV	High Voltage
ICT	Information and Communication Technology
LDC	Load Duration Curve
LPG	Liquid Petroleum Gas
LV	Low Voltage
MV	Medium Voltage
NIG	Non-Intermittent Generation
NPV	Net Present Value

OLTC	On-Line Tap Changer
PMT	Pole-Mounted Transformer
PV	Photovoltaic
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCDF	Sector Customer Damage Functions
SE	State Estimation
SNOP	Soft Normally Open Point
TD	Tumble Dryer
V2G	Vehicle-to-Grid
WH	Water Heater
WM	Washing Machine

Executive Summary

This report has been prepared as the output of D4.3 Grid Impact studies of electric vehicles as part of the Green eMotion project, with the objective to describe key functional specifications for future distribution network planning tools to enable a comprehensive assessment of the impact of electromobility on distribution networks.

The focus of this report is on the requirements for future distribution planning tools rather than the analysis of specific advanced technologies capable of supporting network operation. Although the primary concern in the context of Green eMotion is the integration of EV demand in the distribution planning process, this report takes a broader view by discussing a wide range of advanced network and non-network technologies and their potential synergies and conflicts in the context of widespread deployment of EVs, rather than looking at EV-driven requirements in isolation.

Challenges to distribution network planning

Current planning and operation paradigms of electrical distribution networks are facing fundamental challenges in view of the envisaged decarbonisation of the power industry, in which large-scale integration of electromobility is expected to play an important role. The key concern is that the widespread integration of electrified transport will lead to increases in peaks that are disproportionately higher than corresponding increases in annual electricity demand. This will potentially require significant reinforcement of distribution network infrastructure, while at the same time the utilisation of network capacity will reduce very significantly, increasing the system cost of decarbonising road transport.

A further challenge for European distribution networks is the expected widespread deployment of renewable and low-carbon generation and demand technologies, a large proportion of which will be connected to distribution networks. This will potentially change the direction of power flows and increase the stress on distribution networks, while also introducing significant additional uncertainty.

Under the current, largely passive management approach to distribution network planning, networks are designed to operate with minimum real-time management, and with an in-built capability to deal with the expected worst-case conditions. Any operational issues are effectively resolved at the planning stage, with relatively high investment into network components and, since worst-case conditions occur very rarely, low network utilisation. The aggravation of rare, worst-case conditions by the wide penetration of DG and new transport and heating demand poses significant questions regarding the economic sustainability of this regime. In this respect, an alternative active management regime could significantly improve the utilisation and cost-effectiveness of distribution networks, by enabling Distribution System Operators (DSOs) to deal with network constraints by taking into account the dynamic nature of generation and demand and exercising real-time control of a number of flexible components.

In light of the above, this report argues that a fundamental review of the current distribution network planning and security standards is needed given the need to facilitate a cost-effective evolution to a low carbon energy system through exploiting various Smart Grid

technologies that are critical for the efficient integration of large amounts of distributed renewable generation and flexible demand technologies such as EVs. Future distribution network planning standards and tools should assist network planners in selecting optimal portfolios of network development strategies, including network reinforcement, use of distributed generation, flexible demand (e.g. EVs), application of energy storage technologies and advanced network technologies so that the costs of these options are balanced against the value they bring to network consumers. This is illustrated in Figure E.1. It is also critical for the new tools to take into consideration the risk profile of smart grid solutions, to ensure that adequate levels of reliability are delivered to consumers.

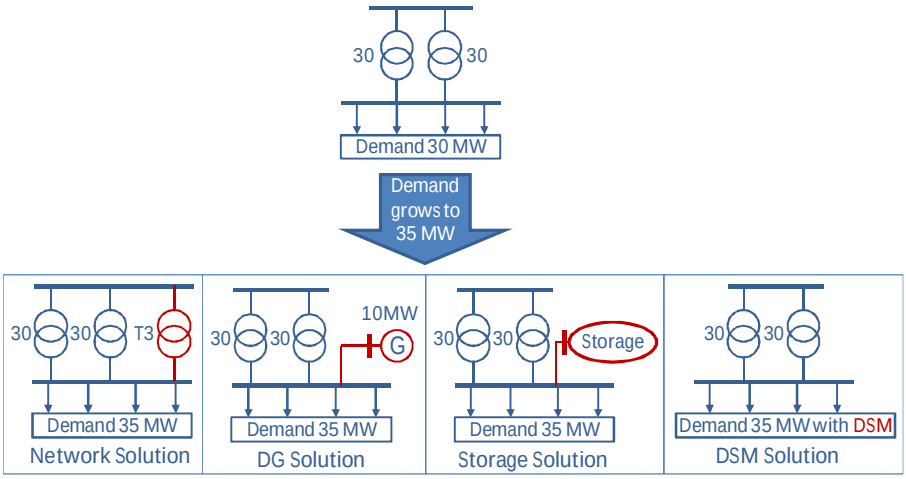


Figure E.1 Range of network and non-network solutions for network security problems

The need to develop new distribution planning methodologies has also been recognised in the recent Research and Innovation Roadmap 2013-2022 published by the European Electricity Grid Initiative (EEGI).[1] The Roadmap argues that new planning approaches and techniques are required that can take into account the next generation of distribution networks, potentially characterised by the presence of renewable generation, active demand, storage and advanced network technologies.

Requirements for future network planning tools

In addition to considering smart non-network solutions, future network planning tools will need to accommodate the improved information on local network conditions provided by advanced network technologies i.e. make use of more precise information on actual network conditions. The interactions with advanced network technologies as well as with distributed generation, demand and storage resources are illustrated in Figure E.2. On the other hand, future planning tools will also have to include the interaction with other segments in the electricity supply chain, in particular with the integration of intermittent renewable generation, but also with the ICT infrastructure needed to operate the network.

[1] European Electricity Grid Initiative, "Research and Innovation Roadmap 2013-2022", January 2013. Available at: http://www.gridplus.eu/eegi.

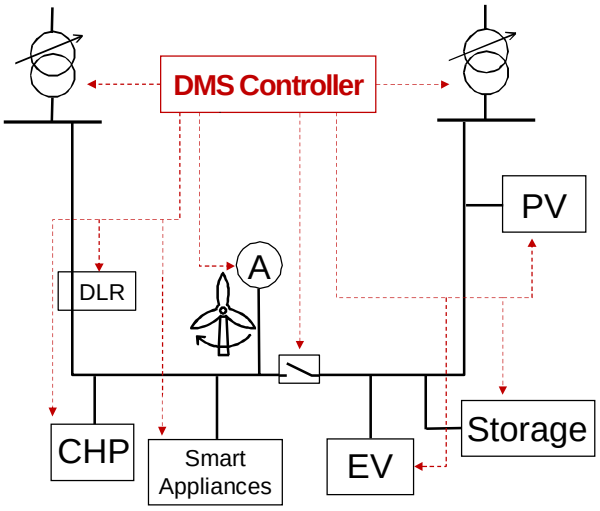


Figure E.2 Active distribution network operation

The transition from a "fit-and-forget" approach towards real-time control of distribution networks will rely on the deployment of advanced ICT technologies, as appropriate communication and control infrastructure will be a necessary prerequisite for active operation and real-time preventive control of distribution networks. Network operation would obviously need to evolve from its current status to intensify the use of ICT in order to make the active network operation a reality. Although the necessary hardware will need to be in place for this transition, the specific ICT infrastructure requirements are not the subject of investigation of this report. The report focuses on methodologies that should be included in distribution network planning tools to account for advanced network and non-network solutions, assuming that these are made available to distribution system operators through appropriate ICT and control infrastructure.

The majority of existing **reliability** tools and techniques in the context of distribution network planning focus on the average or expected performance of the system, and future tools should explicitly characterise the network reliability performance as well as the service quality profile delivered to individual customers, which could vary massively from the system-wide reliability indices. This approach would support a detailed and explicit representation of the effects of alternative network design and operation strategies, involving both network and non-network solutions, on customer reliability of supply. Quantifying the security contribution of non-network solutions, such as flexible EV charging demand, needs to include a careful consideration of their specific operating constraints, such as the energy requirements and flexibility to shift demand in time. Future network planning tools will also need to accommodate the reliability performance of the ICT infrastructure that will be essential for future network operation.

The report presents several examples of using the flexibility of **responsive EV demand** to ensure a more efficient operation of and investment into distribution assets. This approach may reduce network reinforcements significantly through deploying smart EV charging strategies and future distribution network planning tools will need to incorporate these new approaches to network management. Under the smart operation paradigm any constraints associated with EV demand flexibility will need to be incorporated in the future distribution network planning framework, including the risk and cost associated with the supporting ICT infrastructure. Given that the most cost-efficient usage of flexible EVs should adapt to the savings opportunities across the electricity system, drivers for savings in distribution

reinforcement cost may be markedly different depending on the type of the network and on system conditions. Future network planning tools need to be able to take this effect into account, rather than evaluate flexible EV demand or other non-network solution in isolation from the rest of the system, given that minimising only the network cost may not deliver an overall optimum.

A link will need to be established between the **active distribution network operation** solutions and schemes and distribution network planning. It is evident that active network management may lead to significantly lower reinforcements to accommodate new demand from transport (and heat) electrification. Future distribution planning tools need to be able to adequately take into consideration this link between smart network operation and lower requirements for asset redundancy, while giving full consideration to the risk profiles of smart solutions.

The key consideration with respect to using **demand-side response** for distribution network planning and management is that it is not possible to use its flexibility without understanding how particular consumer devices operate. Traditional network planning has treated demand as a fixed input variable with defined levels of power and energy requirements. If demand-side flexibility is to be adequately incorporated into distribution network planning tools, it is necessary to have an understanding of the specific services that this demand delivers. In other words, a comprehensive description is needed of the way electricity is being used by the end customers in order to quantify their capability to redistribute their electricity consumption across time.

Most flexible demand (e.g. EV) and DG technologies are characterised by an inherent **uncertainty**, which introduces significant challenges when integrating these technologies in the distribution planning process. High uncertainty and variability suggests that the present deterministic planning tools based on worst-case snapshots should be replaced by or complemented with probabilistic and stochastic approaches to distribution network planning, also considering the risk implications of increased use of ICT.

Furthermore, current distribution planning tools do not have the capability to propose **alternative network configurations** in order to optimise the average line length in a particular network with respect to the substation density. Ignoring these effects can significantly increase the network reinforcement cost, and the current network design philosophy may not necessarily be optimal for future systems. Future planning tools will therefore need to accommodate the adoption of innovative network designs such as alternative replacement strategies or alternative voltage levels.

Although a number of advanced functionalities needed in future planning tools to adequately include EV demand have already been recognised in the research community, there is currently no harmonised solution as to how to include them in the network planning process. A number of illustrative examples have therefore been included in the report to demonstrate the importance and magnitude of various phenomena related to distribution network planning. Their purpose is to identify the key features and functionalities that should become a part of future distribution network planning tools with particular focus on widespread deployment of EVs. In that context the report is expected to be particularly relevant for DSOs, energy regulators and research institutions with an interest in distribution network planning.

1 Introduction

1.1 Scope

This report represents a part of Deliverable 4.3 of the Green eMotion project. D4.3, titled "Grid Impact studies of electric vehicles", has the objective of assessing the impact of EV recharging infrastructure on local LV distribution networks to facilitate the uptake of EV in the context of urban planning. To achieve this objective, delivery has been organised into five distinct activities: A, B1, B2, B3 and C, as depicted in Figure 1.1.

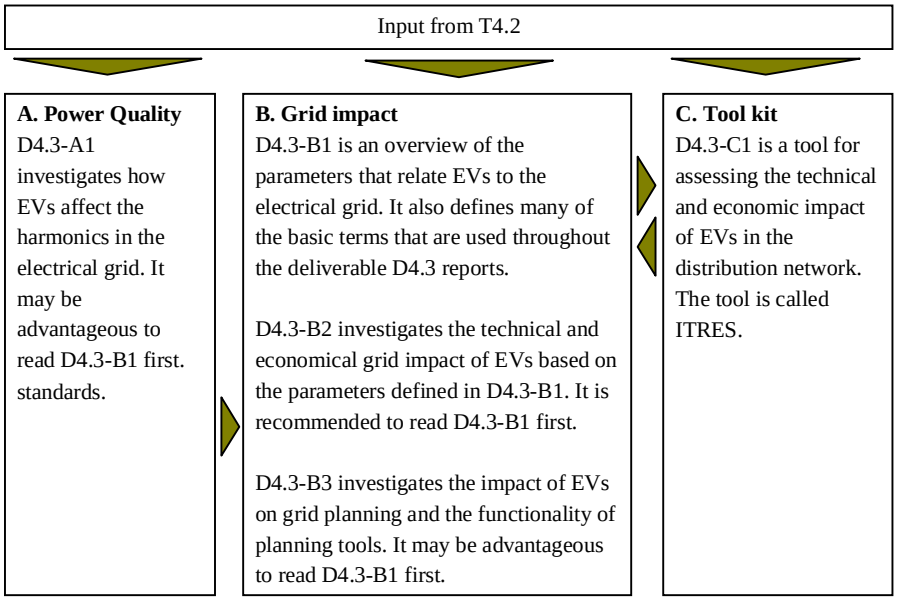


Figure 1.1 Structure of Deliverable 4.3

This report has been prepared as the output of activity B3, with the objective to describe key functional specifications for future distribution network planning tools to enable a comprehensive assessment of the impact of electromobility on distribution networks.

The topic of this report is closely linked to the scope of activities B2 and C1, where a new calculation tool (ITRES) has been developed and applied to determine the LV network reinforcement needed to accommodate EV uptake across multiple years under different charging strategies. Although ITRES provides a sound initial approach within the scope of D4.3 allowing a high-level assessment of the impact of electromobility across different network types, it is possible to envisage how future planning tools used by DSOs might be further enhanced to capture the specific features of new, highly distributed and mobile EV loads. This report therefore aims at identifying the key functionalities that the future network planning tools should incorporate in order to allow for an adequate assessment of EV demand in an environment characterised not only by increased uncertainty, but also by improved network management capabilities at the distribution network level.

The focus of this report is on the requirements for future distribution planning tools rather than the analysis of specific advanced technologies capable of supporting network operation. Although the primary concern in the context of Green eMotion is the integration of EV demand into distribution network planning, this report takes a broader view by discussing a

wide range of advanced network and non-network technologies and their potential synergies and conflicts in the context of widespread deployment of EVs, rather than looking at EV-driven requirements in isolation.

Among other sources, the content of this report draws on the discussions held during a dedicated workshop on the topic of future distribution network planning tools, which took place at Imperial College London on 24 May 2013. The authors duly acknowledge the contributions of research teams from EDF R&D, DEA and Iberdrola to the discussions during the workshop. The same partners also provided valuable help by commenting on the first draft versions of this report. Finally, the authors are grateful to the ESB Ecars team, which reviewed the final draft version of the report and provided very helpful feedback.

1.2 Links with previous deliverables

The work presented in this report builds upon the findings of previous reports prepared within WP4. This is in particular true for the reports Deliverable 4.3-A1 "EVs impact on Power Quality related to harmonics: When adding EVs to low voltage grids" and Deliverable 4.3-B2 "Electric Vehicles and Grid: Reinforcement Costs in Low Voltage Grids". Their key findings are therefore summarised below.

The key objective of **Deliverable 4.3-A1** was to characterise the impact of EVs on harmonics in LV distribution networks where households are a dominant demand category. The assessment has been carried out assuming home charging of EVs at 16 A and 230 V. The report presented harmonic load flow simulations carried out using the Power Factory software[2] for three charging strategies: (i) user-dependent, (ii) timer-based and (iii) load-dependent, evaluated on 6 specific LV networks.

The analysis suggests that harmonic emissions from EVs are not expected to create a need for network reinforcement in nearest future. The results show that sufficient short circuit level is the most important parameter to avoid harmonic distortion, which should be considered when extending or reinforcing the existing networks. It was also shown that the total level of harmonics highly depends on other types of equipment connected to the network.

Smart meters capable of measuring harmonics can play a key role in the future to enable the integration of harmonics into network planning, given that a comprehensive collection of data on harmonics has traditionally been very expensive. An evolution of the already existing functionalities related to harmonics in today's smart meters could provide the required data, and therefore facilitate the including of harmonics into future network planning tools.

Deliverable 4.3-B2 quantified the impact of EVs on the reinforcement of LV distribution networks, focusing on how different EV parameters[3] affect the reinforcement costs. The evaluation of reinforcement requirements has been done by developing and analysing a set of scenarios that vary the following key parameters: (i) charging power, (ii) charging profile, (iii) EV location, and (iv) EV penetration. Reinforcement schedules and the corresponding costs (expressed as net present values) obtained using the ITRES tool have been analysed and compared across all key parameters. The results suggested that the key parameter was

[2] http://www.digsilent.de/index.php/products-powerfactory.html.
[3] Selection of EV parameters that were analysed in the study has been elaborated in Deliverable 4.3-B1 "Grid impact studies of electric vehicles: Parameters for assessment of EVs impact on low voltage grid".

the charging profile, i.e. charging management strategy. A grid-friendly charging management approach could avoid significant reinforcements and the associated costs.

The results also indicated that a simple timer-based charging management strategy could result in a less grid-friendly charging process due to the charging synchronisation effect, leading to significantly increased reinforcement costs in many of the analysed networks. More elaborate timer-based charging management could avoid the negative effects on reinforcement costs, while still providing the benefits of moving EV charging away from the existing load peaks.

The report showed that variations in EV penetration and charging power had a significant impact on reinforcement costs, stressing the importance of accurate forecasting. EV location was also found to have a critically significant impact on reinforcement costs, which showed that in order to evaluate the reinforcement of a network, it is necessary to know the exact location of EVs. It was further concluded that the use of advanced voltage control could defer the majority of reinforcements associated with voltage issues, allowing long feeders to accommodate a significantly larger amount of EVs before reinforcement is necessary.

The report clearly identified the need for new planning tools that can better estimate the economic impact of different solutions and allow more flexibility when it comes to forecasting of load. New methods may also be necessary for load estimation and forecasting, especially in cases with fewer customers and flexible loads where average values provide poor estimates. These requirements for future planning tools are investigated in more detail in this report.

1.3 Challenges to distribution network planning

Current planning and operation paradigms of electrical distribution networks are facing fundamental challenges in view of the envisaged decarbonisation of the power industry, as European governments have taken significant initiatives in response to environmental and climate change concerns, in which large-scale integration of electromobility is expected to play an important role.

The key concern is that the widespread integration of electrified transport will lead to increases in peak demand that are disproportionately higher than corresponding increases in annual electricity demand (even if radical energy efficiency measures are undertaken). This will potentially require significant reinforcement of network infrastructure, in particular at the distribution level, while at the same time the utilisation of network capacity (i.e. the average loading factors) will reduce very significantly, increasing the system integration costs of decarbonising road transport.

Furthermore, distribution networks in Europe are likely to face additional challenges. In the next twenty years a wide deployment of renewable and low-carbon generation and demand technologies is expected. Due to renewable energy resource availability and techno-economic constraints, a large proportion of such generation will be connected to different levels of European distribution networks, as distributed generation (DG). While distribution network design and planning has been traditionally driven only by load growth and has only considered unidirectional power flows from the transmission system to end consumers, the wide connection of DG and potentially distributed storage installations will create substantial reverse flows and increase significantly the stress on distribution networks. Also, the majority of those sources are characterised by an inherent unpredictability and intermittency. Levels of penetration of both new generation and demand technologies is characterised by

significant uncertainty, while the network existing planning tools are fundamentally deterministic.

Going forward, technological developments have paved the way for the electrification of heat and transport sectors, which is envisaged to further reduce the carbon intensity of energy supply beyond the 2030 horizon. This technological transition, in the form of a massive roll-out of electric vehicles (EVs) and electric heating, will introduce a very significant amount of new demand into distribution networks. Moreover, due to the temporal use patterns of vehicles and heating systems by the consumers, the distribution network investment costs required to support the introduction of such new demand are likely to be disproportionately higher than the increase in total electricity consumption. On the other hand, these new demand types could mitigate the network reinforcement cost if operated in a flexible way.

Adequate incorporation of the above demand-side and DG technologies into distribution planning tools is therefore essential in order to ensure efficient and secure development and operation of distribution networks in the future.

Under the traditional or passive management distribution network planning regime, networks were designed to operate with minimum real-time management, and with an in-built capability to deal with the expected worst-case conditions. Any operational issues were effectively resolved at the planning stage, with relatively high investment into network components and, since worst-case conditions occur very rarely, low network utilisation. The aggravation of rare, worst-case conditions by the wide penetration of DG and new transport and heating demand poses significant questions regarding the economic sustainability of this regime.

In these terms, an alternative active management regime could significantly improve the utilisation and cost-effectiveness of distribution networks. Under this approach, rather than planning and operating the network in anticipation of worst-case conditions, Distribution System Operators (DSOs) deal with constraints during different system conditions by taking into account the dynamic nature of generation and demand and exercising real-time control through a number of flexible components, similarly to what is done in the transmission network. Hence, the use of existing assets is maximised and the required investment may be considerably lower. On the other hand, additional information, communication and control assets required for active control need to be included in the distribution investment and operating costs, while higher network utilisation will also have an adverse impact on network losses.

These flexible components include not only network control technologies (power electronic devices, coordinated voltage control, soft normally open points, dynamic line rating measures etc.) but also DG, storage and demand technologies exhibiting a ‘smart’ operation potential. The contribution of these components to the mitigation of network constraints requires the establishment of novel commercial arrangements for the interaction of the owners of these technologies with the DSOs, such as non-firm connection of DG or dynamic pricing schemes for flexible loads.

Finally, one should not neglect that many of current European distribution networks were predominantly built in 1950s and 1960s and may reach the end of their usable life in the next couple of decades. This coincidence offers the opportunity to design the networks of the future considering the above opportunities for real-time controllability and cost-effectiveness, rather than following like-with-like asset replacement philosophy.

1.4 Requirements for future network planning tools

In light of the above, this report argues that a fundamental review of the current distribution network planning and security standards is needed given the need to facilitate a cost-effective evolution to a low carbon energy system through exploiting various Smart Grid technologies that are critical for the efficient integration of large amounts of distributed renewable generation and flexible demand technologies such as EVs. Future distribution network planning standards and tools should assist network planners in selecting optimal portfolios of network development strategies, including network reinforcement, use of distributed generation, flexible demand (e.g. EVs), application of energy storage technologies and advanced network technologies so that the overall investment costs of these options is balanced against the value they bring to delivering quality of supply to network consumers and their impact on the cost of network losses and maintenance. It is also critical for the new tools to include the implications of these advanced solutions for network security, i.e. take into consideration the risk profile of smart grid solutions, to ensure that adequate levels of reliability are delivered to consumers.

The need to develop new distribution planning methodologies has also been recognised in the recent Research and Innovation Roadmap 2013-2022 published by the European Electricity Grid Initiative (EEGI).[4] The Roadmap argues that new planning approaches and techniques are required that can take into account the next generation of distribution networks, potentially characterised by the presence of renewable generation, active demand, storage and advanced network technologies.

Future network planning tools will need to accommodate the improved information on local network conditions provided by advanced technologies such as Dynamic Line Rating or Condition Monitoring, i.e. make use of more precise information on actual network conditions, as envisaged to be applied in distribution networks according to the EEGI Roadmap and several other research activities. On the other hand, future planning tools will also have to include the interaction with other segments in the electricity supply chain, in particular with the integration of intermittent renewable generation, but also with the ICT infrastructure needed to operate the network.

The majority of existing reliability tools and techniques in the context of distribution network planning focus on the average or expected performance of the system, and future tools should explicitly characterise the network reliability performance as well as the service quality profile delivered to individual customers. This approach would support a detailed and explicit representation of the effects of alternative network design and operation strategies, involving both network and non-network solutions, on customer reliability of supply. This is critical since the actual service quality delivered by distribution networks to individual customers varies massively and is generally very different from the system-wide reliability indices.

Quantifying the security contribution of non-network solutions needs to include a careful consideration of their specific operating constraints, such as the energy requirements of EV users and their flexibility to shift demand in time. Furthermore, future network planning tools will need to accommodate the reliability performance of the ICT infrastructure that will be

[4] European Electricity Grid Initiative, “Research and Innovation Roadmap 2013-2022”, January 2013. Available at: http://www.gridplus.eu/eegi.

essential for future network operation as the present planning tools do not consider ICT explicitly in distribution reliability assessment.

The report presents several examples of using the flexibility of responsive EV demand to ensure a more efficient operation of and investment into distribution assets. This approach may reduce network reinforcements significantly through deploying optimal EV charging strategies and future distribution network planning tools will need to incorporate these new approaches to network management. Under the smart operation paradigm, which optimises EV charging in real time to minimise its impact on the network, any constraints associated with EV demand flexibility will need to be incorporated in the future distribution network planning framework, including the risk and cost associated with the supporting ICT infrastructure.

A link will need to be established between the active distribution network operation solutions and schemes and distribution network planning. It is evident that active network management may lead to significantly lower reinforcements to accommodate new demand from transport (and heat) electrification. Future distribution planning tools need to be able to adequately take into consideration this link between smart network operation and lower requirements for asset redundancy, while giving full consideration to the risk profiles of smart solutions.

Most DG and flexible demand technologies (e.g. EV) are characterised by an inherent uncertainty, which introduces significant challenges when integrating these technologies in the distribution planning process. High uncertainty and variability suggests that the present deterministic planning tools based on worst-case snapshots should be replaced by probabilistic and stochastic approaches to distribution network planning, also considering the risk implications of increased use of ICT.

Furthermore, current distribution planning tools do not have the capability to propose alternative voltage levels, or network splitting techniques in order to optimise the average line length in a particular network with respect to the substation density. Ignoring these effects can significantly increase the network reinforcement cost, and the current network design philosophy, which has been introduced at the end of 1950's, may not necessarily be optimal for 21st century systems. Future planning tools will therefore need to accommodate the adoption of innovative network designs such as alternative replacement strategies or alternative voltage levels.

Although a number of advanced functionalities needed in future planning tools have already been recognised in the research community, also including the considerations related to high uptake of EVs, there is currently no harmonised solution as to how to include them in the network planning process. A number of illustrative examples have been included in the report to demonstrate the importance and magnitude of various phenomena related to distribution network planning and including EV demand in the planning process. Their purpose is to identify the key features and functionalities that should become a part of future planning tools.

The purpose of the report is to highlight the new functionalities for future network planning tools and in this context it is considered to be relevant to audience with a general interest in distribution network planning. The topics covered in the report should be particularly interesting for: 1) DSOs, as one of their key functions is to maintain and develop distribution networks in order to support an efficient and secure supply of electricity to end customers; 2) energy regulators, due to their remit to regulate distribution business and incentivise

efficient delivery of distribution infrastructure; and 3) research institutions involved in investigating novel approaches to distribution network planning.

1.5 Report structure

In this context the report discusses the functionalities required for future design and planning of distribution systems. The report is organised as follows. Section 2 discusses the challenges related to the incorporation of EV demand into distribution planning. Section 3 demonstrates the potential value of alternative LV network reinforcement strategies. Network constraints that should be addressed by new tools and the interaction with the wider electricity system are introduced in Section 4. In Section 5, we provide an outline of the new conceptual framework required for planning future distribution networks. Finally, Section 6 concludes this report.

2 Including EVs into distribution network operation and planning

Given that the focus of the Green eMotion project is on a Europe-wide integration of electromobility, it is of particular interest in this report to identify how to include new EV demand into future distribution network planning tools. Potentially flexible EV demand can contribute to a significantly enhanced operation of and investment into distribution networks. Future planning tools will need to be able to consider a variety of EV charging strategies in terms of potential reduction of network reinforcements. Clearly, under the smart EV charging paradigm, which optimises EV charging in real time to minimise the impact on the network, any constraints associated with EV demand flexibility will need to be incorporated in the future distribution network planning framework, including the risk and cost associated with the supporting ICT infrastructure.

This section therefore presents several examples of using the flexibility of responsive EV demand to ensure a more efficient operation and investment into distribution assets, and outlines the potential benefits of integrating smart meter-enabled EV demand, with appropriate functionality and communication systems, into real-time distribution network control. The aim of the approach is to reduce the necessary network reinforcement through deploying optimal EV charging strategies.

In the context of the future costs of network reinforcement driven by the adopted network control and design practices, it is possible to contrast two approaches to EV charging management:

- *Business as Usual (BaU)* where EV users charge their batteries at their convenience (e.g. upon completing their return journey home);
- *Smart*, involving real-time network management through optimised EV charging.

Under the 'Smart' operation paradigm, which optimises EV charging in real time to minimise the impact on the network, any constraints associated with EV demand flexibility need to be respected, so that any compromise on the quality of service required by the EV user (e.g. EVs are charged so that every intended journey can be carried out) is considered and appropriate choices made by the network users.

2.1 Flexible EV demand in distribution network operation

With the expected increase in the numbers of EVs connected to the distribution network, it will become increasingly expensive to supply their electricity requirements using a passive "predict and provide" paradigm, as the potentially high increases in peak demand may require substantial reinforcements in local distribution grids. It will therefore become critical to develop and implement solutions which will enable the flexibility of EV demand to be used to support a more efficient design and operation of distribution networks.

There are two fundamental approaches to implementing EV charging control as part of an active paradigm for distribution network control:

- *Direct control*, where flexible EV charging in a given distribution area is centrally coordinated to ensure efficient network utilisation, while respecting the EV users' energy requirements.[5]

- *Price-based control*, where flexible EV loads respond to locational price signals, which reflect the scarcity of both energy and network capacity at any given time.[6]

The two approaches are illustrated in Figure 2.1. The arrows in the figure indicate the data and signals communicated between DSOs and EV users.[7]

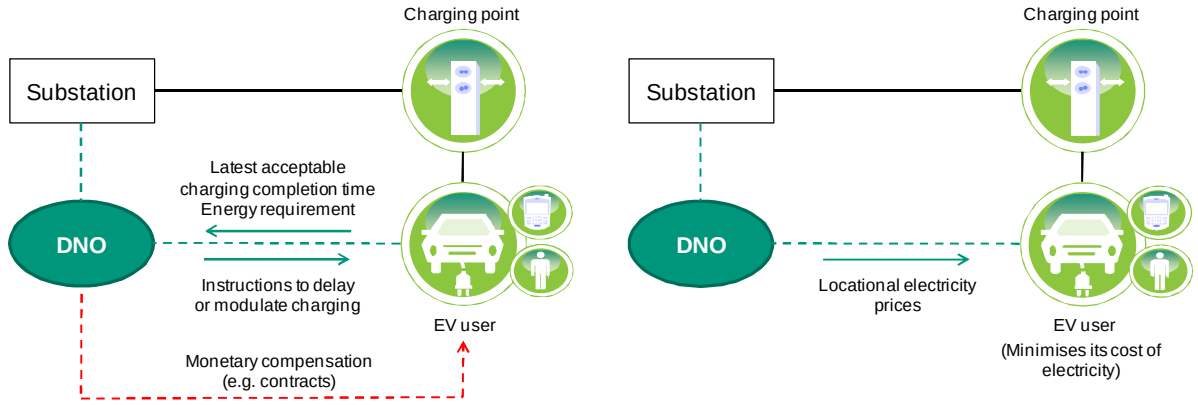


Figure 2.1 Direct (left) and price-based control (right) of EV charging for distribution network operation

In the direct control approach, the EV users communicate to the DSO their energy requirements and any flexibility in terms of the allowed delay in battery charging, in order to ensure that charging control does not prevent their batteries to be at the desired state of charge when they are next needed. In practice, this could mean that an EV user connects its vehicle to the charging point and does not opt for immediate charging, but rather allows a certain delay (of user's own choice) in the delivery of the required energy. DSO on the other hand monitors the condition of the network, and decides whether at any time there is a need to control i.e. delay EV charging in order to avoid network problems. DSO issues instructions to delay charging or reduce charging power to that effect, while respecting the energy requirements and timing specified by EV users. EV users participating in this type of control would in return expect financial compensation, which might be defined through bilateral contracts between the EV users and DSOs.

In the price-based control, it is assumed that EV users make their own choices on when to charge their batteries based on the location-specific price signals communicated by the DSO through a suitable channel (e.g. smart meters). In order to ensure economic efficiency, the prices seen by the EV users need to adequately reflect the level of scarcity in the system at each location, incorporating both the cost of generating electricity in the system at a given

[5] "Benefits of Advanced Smart Metering for Demand Response-Based Control of Distribution Networks", report for the Energy Networks Association, April 2010. Available at www.energynetworks.org.
[6] D. Papadaskalopoulos, G. Strbac, "Decentralized participation of electric vehicles in network-constrained market operation", 3rd IEEE PES International Conference and Exhibition on Innovative Smart Grid Technologies (ISGT Europe), Berlin, 2012.
[7] The diagrams do not consider any aggregators or intermediaries between EVs and DSOs, as their purpose is primarily to illustrate different concepts of EV charging control.

moment, and the loading level of local network components. At times when network loading is at its peak, the prices should reflect this by rising to higher levels, especially in those parts of the network which are operating closest to its maximum capacity. The rational response of flexible EV users would then be to postpone their charging until the prices have reached acceptable levels (i.e. during off-peak hours), or even choose an alternative mode of transport, effectively exercising a decentralised price-based control that does not require a direct instruction from the DSO or any other entity.

In addition to minimising network reinforcement, cost-minimising EV users may also reduce payments for other demand participants in such a decentralised market framework, improving the overall social welfare. In other words, inflexible demand, and especially its part concentrated around afternoon/evening peak hours may see significant price reductions due to the migration of flexible EV demand away from peak hours. This may also result in significant reductions in both the cost of network constraints and congestion surplus.

Similar to other aspects of active network operation, there will need to be a link between the selected approach to flexible EV charging control for a given network and the network planning activity being carried out by the respective DSO. The level of involvement of flexible EV demand in active network operation will have obvious implications in reducing or deferring necessary investments into distribution grid reinforcement. It is therefore critical that the knowledge about flexible EV demand in a distribution area is appropriately taken into consideration when making network planning decisions and future distribution network planning tools will need to incorporate this.

2.2 Impact of EV charging on load diversity in distribution network planning

The concept of load diversity has been one of the key factors for distribution network planning since the 1950s.[8] It represents a critical parameter for determining the maximum demand of a group of customers, which in turn is a key driver for investing into new or upgraded network assets. Load diversity has been particularly relevant for planning residential LV networks, since there has traditionally been little specific information available about residential LV loads. Because of the diversity effect the network does not need to be able to withstand the worst possible combination of customer demands, as its occurrence is extremely improbable. With the deployment of EVs and other low-carbon demand technologies, the issue of quantifying load diversity is expected to become additionally important.

Load diversity increases with the number of customers, and normally converges to a certain stable level with increasing customer group sizes. Several techniques for estimating the peak demand of a group of customers have been proposed in the relevant literature,[9] most of which use the *coincidence factor* defined as the coincident peak demand of a group of customers within a specified period divided by the sum of their individual maximum demands within the same period. An illustration of the functional relationship between the coincidence factor and the number of customers is provided in Figure 2.2. Although it is evident that the coincidence factor decreases with a larger number of customers, the figure also illustrates

[8] S. Rusck, “The simultaneous demand in distribution network supplying domestic consumers”, ASEA Journal, vol. 10, 1956, pp. 59-61.
[9] J. Dickert, P. Schegner, “Residential load models for network planning purposes”, Proceedings of the International Symposium on Modern Electric Power Systems 2010, Wroclaw, Poland.

the uncertainty in determining the exact functional relationship between the coincidence factor and the number of customers.

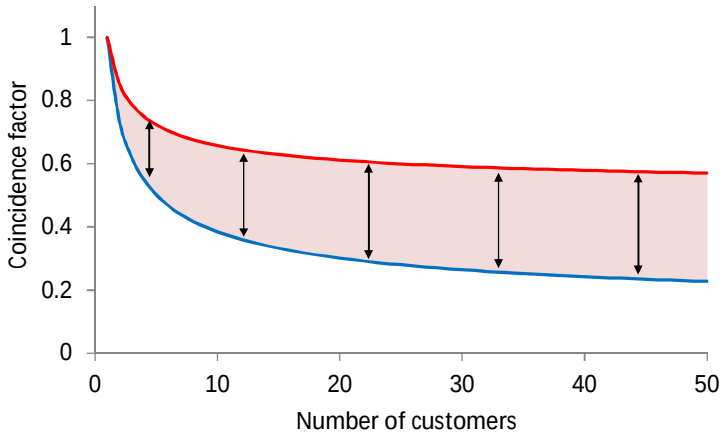


Figure 2.2 Coincidence factor as the function of the number of customers and the underlying uncertainty

Diversity considerations are expected to become even more critical in the future characterised by a widespread deployment of EVs across the LV networks. A similar impact may also arise from deploying other low-carbon demand technologies such as e.g. electrified heating based on heat pumps. Although the methodology for estimating the diversity of conventional loads is rather well established, the approaches to characterise the diversity of new demand categories such as electromobility are yet to be developed, and the corresponding impact on coincident network peak demand at both low and high penetration rates needs to be further understood.

The coincidence factor for peak EV charging demand will greatly depend not only on daily journeys undertaken by EV users, but also on any smart or controlled charging strategies that might be pursued in order to reduce the total peak demand on distribution networks. Depending on the strategy adopted, the effect of controlled charging may lead to a significantly lower contribution of EVs to the overall network peak demand and consequently to lower requirements for network reinforcement.

One possible approach to characterise the diversity of EV demand has been developed by DEA in Deliverable 4.3-B1, as illustrated in Figure 2.3.[10] The depicted EV charging profiles have been used as input to ITRES tool to calculate the necessary distribution network reinforcement resulting from EV deployment for several examples of LV networks in Denmark, Italy and Spain.

[10] C. K. Madsen, F. Ö. Thordarson, J. Rasmussen, "Grid impact studies of electric vehicles: Parameters for assessment of EVs impact on low voltage grid", Green eMotion Deliverable 4.3-B1, November 2013.

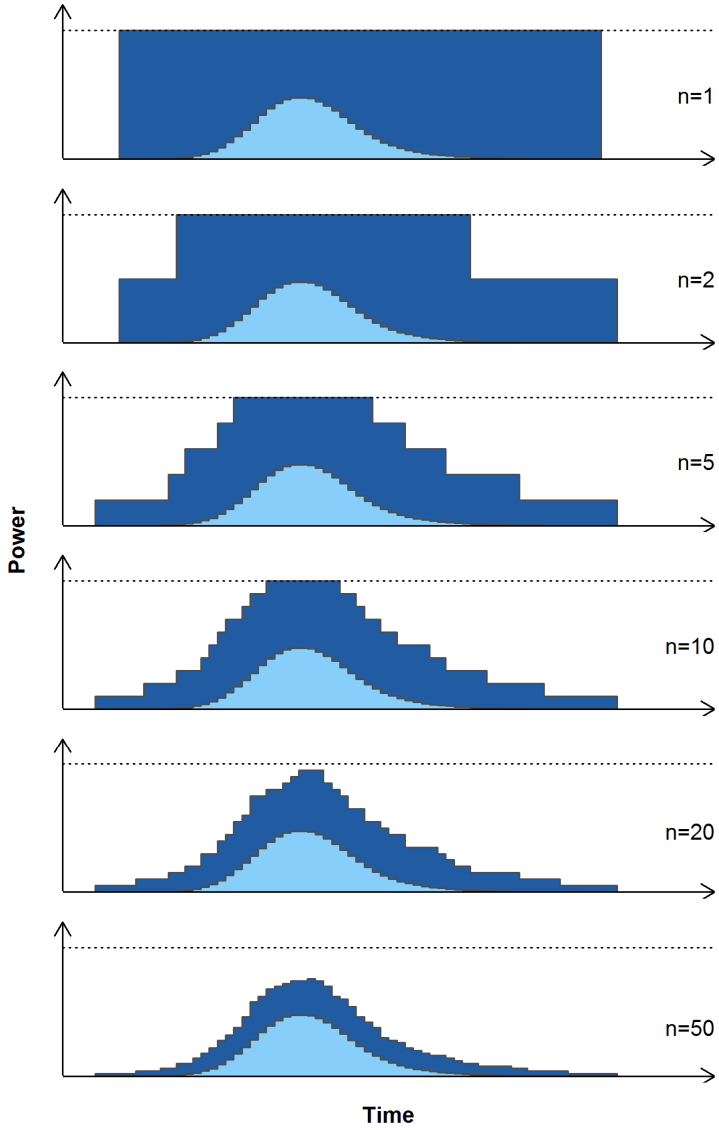


Figure 2.3 Comparison between probable and average user-dependent charging profiles for different numbers of EVs on the grid (Source: DEA, Deliverable 4.3-B1)

Given that no EV population data has been available to DEA for the analysis, the approach to deriving the charging profiles in Figure 2.3 was to generate synthetic subsamples of EV journeys based on the assumed probability distributions of morning departure times, time spent at work and time spent on journeys to and from work.[11] The generated samples served as the basis for estimating the energy requirement and consequently, depending on the assumed charging strategy, for generating charging profiles (uncontrolled i.e. user-dependent charging was assumed in Figure 2.3). When assessing the impact of a small number of EVs on the LV grid, the smooth shape of the probability distribution of arrival times cannot be directly used by applying the average charging profile of a large population multiplied by the number of vehicles. Therefore, a large number of samples were generated for different numbers of EVs, and the probable worst-case charging profiles depicted in

[11] The assumption was that all EV users in the sample leave to work in the morning and return home in afternoon or evening.

Figure 2.3 were determined corresponding to the 99th percentile within the sampled EV demand of each group size.

Figure 2.3 clearly demonstrates the common statistical feature of larger samples to exhibit smaller relative variations. The coincidence factor for this EV population drops below 1 for group sizes of 20 and above. It has to be noted that the shapes of probable and average charging profiles become markedly different for different approaches to charging control, such as timer-based charging or grid-optimised charging, as quantified in Deliverable 4.3-B2. In terms of distribution network planning, it is further important how EV demand profiles combine with the remaining network load, i.e. how EVs affect the total peak demand relevant for equipment sizing.

In order to assess the impact of EV demand on distribution network infrastructure in a realistic environment, it will be necessary to have a detailed understanding of the statistical properties of EV users' behaviour in a given area. This type of information, which has not been featured in traditional network planning tools, will need to become a standard input into the planning process if a widespread deployment of EVs becomes a reality.

2.3 Reduced network reinforcement due to EV charging control

EV loads are particularly well placed to support network operation: given their relatively modest amount of energy required; the short driving times generally associated with small passenger vehicles (vehicles are stationary on average for about 90% of the time); and given that the batteries have relatively high power ratings. Clearly, there is considerable flexibility regarding the time when the vehicles can be charged and this can provide significant benefits both to the operation of distribution and transmission networks and to the efficient dispatch and utilisation of generation.

In that context, the example presented in Figure 2.4 illustrates the impact of Smart EV charging vs. BaU operation on the reinforcement requirements in a representative semi-urban/rural LV network with a load density of 2 MVA/km^2.[12] Smart charging assumes that EV demand can be shifted in time while respecting the energy requirements and journey times of vehicle users. This example considers different levels of EV penetration in the network, ranging between 25% and 100%. The results show that Smart EV charging results in a significant reduction in overloads over the BaU paradigm. The benefits of Smart operation in terms of avoiding the overloading of distribution network elements are very significant even for very high levels of penetration, given the flexibility of transport demand (relatively low energy requirements, relatively high power ratings of batteries combined with a very significant proportion of time available for charging).

[12] Source: "Benefits of Advanced Smart Metering for Demand Response-Based Control of Distribution Networks", report for the Energy Networks Association, April 2010.

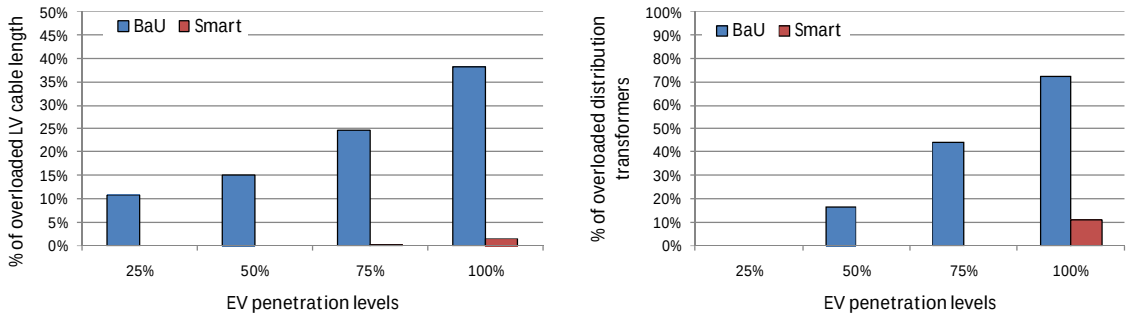


Figure 2.4 Percentage of overloaded LV feeder length and distribution transformers for different penetrations of EVs assuming average driving patterns

In the above analysis it was assumed that average driving patterns observed at the national level would be statistically similar to those at the local level. In contrast, the potential impact of driving patterns associated with commuting to a town/business park area in the morning and making return journeys in the evening is likely to have a different impact. This will lead to more concentrated EV charging in the morning hours, given the typical arrival times to town/business park areas of between 8am and 9am and evening charging driven by typical home arrival times of between 6pm and 8pm.

To illustrate this, a commercial district area is analysed considering both BaU and Smart mode of operation. As expected, a significant increase in morning peak demand under BaU would be driven by concentrated EV charging, as illustrated in Figure 2.5. On the other hand, a very flat profile can be obtained if charging is optimised.

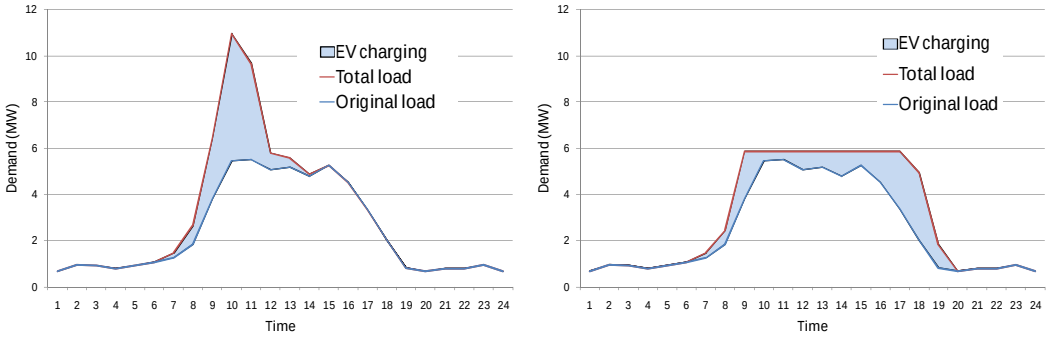


Figure 2.5 BaU (left) and Smart (right) demand profile in a commercial district (1 km^2) driven by charging of 5,000 EVs following arrivals to work

Figure 2.6 shows the percentage of low voltage (LV) and high voltage (HV)[13] lines and primary and distribution transformers that would be overloaded under both a BaU and a Smart regime of EV charging for the example of a commercial area presented in Figure 2.5.[14] The results indicate that smart charging for EV is critical to mitigate expensive network reinforcement. By maintaining the BaU approach, the network reinforcement cost could be 8 times higher than under an active network control regime.

[13] HV in the UK includes voltage levels of 11 kV and 33 kV, while in the rest of Europe these voltage levels are more commonly referred to as medium voltage (MV).
[14] Source: "Benefits of Advanced Smart Metering for Demand Response-Based Control of Distribution Networks", report for the Energy Networks Association, April 2010.

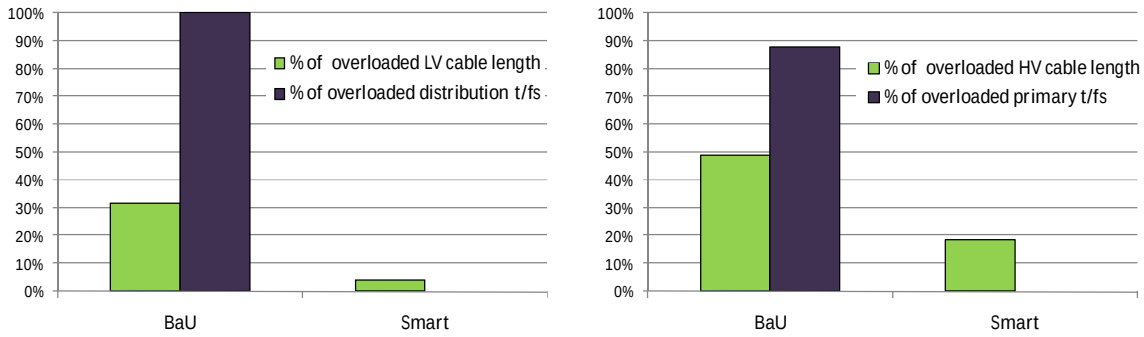


Figure 2.6 Percentage of overloaded distribution transformers and LV feeders (left) and primary substations and HV feeders (right) under BaU and Smart operating regime in a commercial district driven by charging of EV following arrivals to work

The example shown in Figure 2.7 illustrates the likely changes in demand profile for the case in a residential area driven by the EV charging when people return home from work for both BaU and Smart modes of operation. As expected, peak demand is observed in the evening as charging is assumed to start upon arrival at home from work. It is assumed that evening charging will recover the energy of the return journey only, while the energy associated with the journey to work is recovered through charging during working hours at the workplace). Under a Smart operating regime, this demand peak (and hence a massive network reinforcement cost) can be avoided as shown in Figure 2.8.

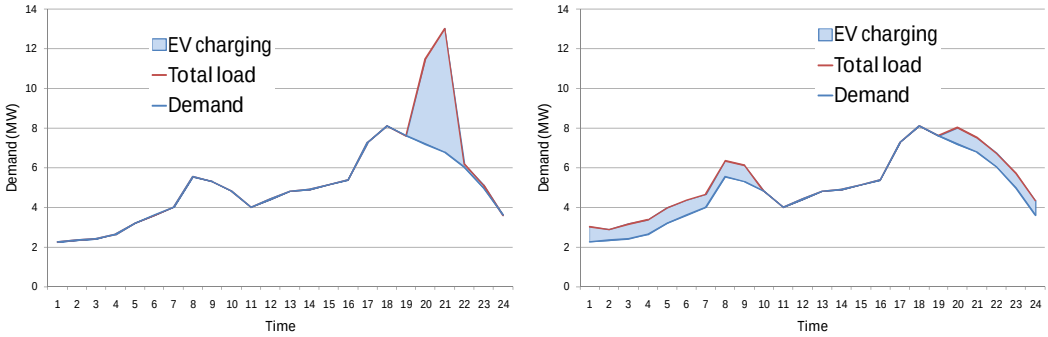


Figure 2.7 BaU (left) and Smart (right) charging in a residential area (8,000 properties) driven by charging of 5,000 EVs when people return from work

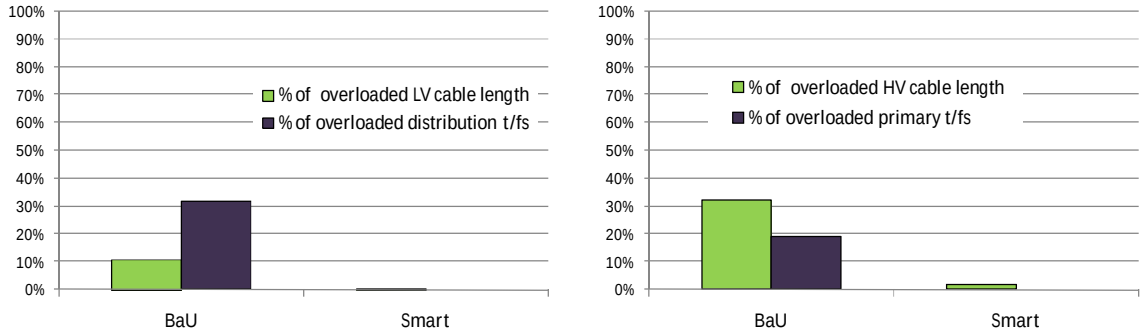


Figure 2.8 Percentage of overloaded distribution transformers and LV feeders (left) and primary substations and HV feeders (right) under BaU and Smart operating regime in residential area driven by charging of EV following return from work

2.4 Impact of EV charging strategies on network reinforcement cost in long-term uptake scenarios

As another illustration of the impact of the approach to EV charging control on the distribution network reinforcement cost, an example case study is presented for UK distribution networks where the uptake of EVs is expected to reach 18 million in 2050 following a trajectory presented in Figure 2.9.[15] This analysis is based on the authors' previous work on studying the impact of EVs on distribution networks.

The total EV number also distinguishes the evolution of EV uptake in different population area types – urban, sub-urban and rural – which also have distinct features in terms of distribution network topology. About 50% of EVs are projected to appear in sub-urban areas, followed by urban and then rural areas. This is highly correlated with the fact that most distribution networks are classified as semi-rural or semi-urban networks.

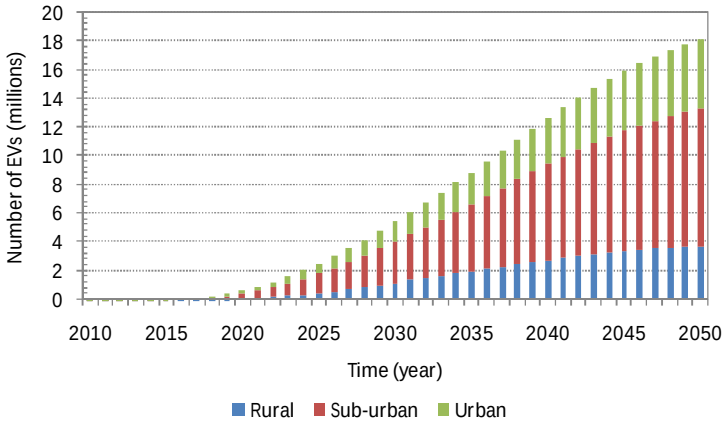


Figure 2.9 Example of an EV uptake scenario

[15] The EV uptake scenario presented in the figure broadly corresponds to the "Medium" uptake scenario used in Deliverable 4.3 – B2 report "Electric Vehicles and Grid: Reinforcement Costs in Low Voltage Grids". According to the report, this scenario reflects the medium penetration forecast for Denmark and the high penetration forecast for EU as a whole.

The objective of this case study was to assess the likely incremental impact of EVs on distribution networks through evaluating likely network reinforcements needed to support the increase in electricity demand and quantify associated costs. These costs can be mitigated by adopting various measures, and this example focuses in particular on investigating the cost effectiveness of introducing intelligence in charging of EVs combined with the application of Voltage Regulators in LV networks.

Mitigation possibilities with EV charging control include (as illustrated in Figure 2.10):

- Charging after each journey (O1) – requires on-street, commercial or workplace charging posts.
- Evening home charging (O2) – likely to lead to significant increase in peak demand and will hence require significant reinforcement; on the other hand requires no specific charging infrastructure.
- Off-peak (overnight) EV charging (O3), optimised to the national load profile is likely to require significantly lower reinforcement costs, given much more modest increase in peak demand.
- Locally optimised EV charging (O4) – maximises the utilisation of the local network and minimises the increase of network peak demand, which may not require any network reinforcement.

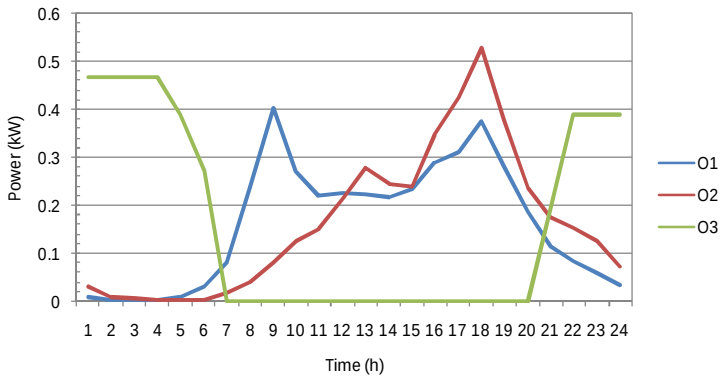


Figure 2.10 Diversified EV demand profiles for different charging strategies

In order to illustrate the magnitude of the impact of different EV charging strategies on network reinforcement, Figure 2.11 presents an example of a semi-rural distribution network that needs to accommodate three different EV penetration levels: Low (0.6 EVs per household), Medium (1.4 EVs per household) and High (2 EVs per household). Reinforcement cost per consumer is presented on the vertical axis, broken into the cost of LV circuits due to thermal constraints (LV-I) or voltage constraints (LV-V), distribution transformers (HV/LV), HV circuits, primary substations (EHV/HV) and the EHV network and above including other costs such as legal and administrative fees (EHV+).

It can be observed that the network reinforcement is primarily driven by voltage constraints and in some cases by the thermal constraints of distribution transformers. At low EV penetrations the reinforcement can be fully mitigated by adopting either O3 or O4 charging control. For medium to high EV penetrations the reinforcement cost increases significantly, although the advanced charging control options (O3 and O4) are able to significantly reduce the cost of reinforcement.

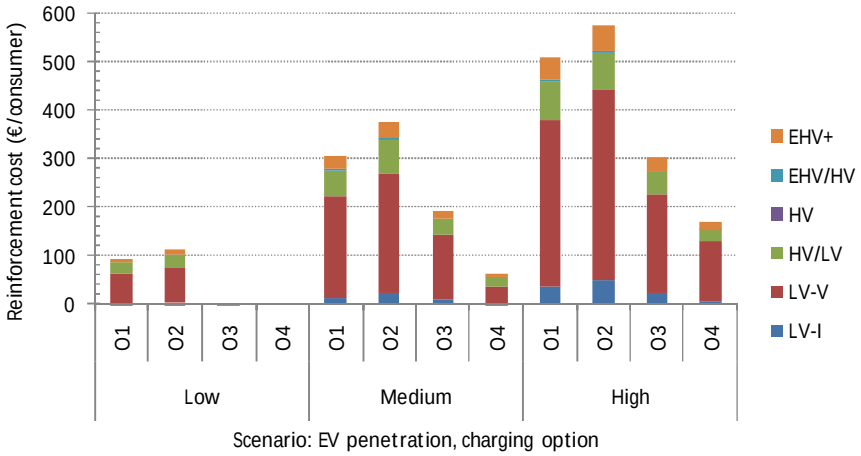


Figure 2.11 Reinforcement cost for various EV penetrations and charging options

Given that a relatively significant proportion of network reinforcement cost due to a large-scale introduction of EVs may be driven by voltage constraints, particularly in semi-urban/rural networks illustrated above, the potential for reducing network reinforcement cost through LV voltage control facilitated with in-line voltage regulators with an on-load tap changing capability may be significant. Implementation of voltage control at LV network as a mitigation measure to reduce network reinforcement is therefore considered in conjunction with different EV charging approaches.

Based on the above, a number of EV charging control scenarios have been assumed in the study, as specified in Table 2.1.

Table 2.1 EV charging control scenarios

Scenario	Description
BaU	Network is upgraded to accommodate domestic EV charging
BaU.VC	Introduction of voltage control at the LV network in order to reduce a possible network upgrade required to accommodate domestic EV charging
Smart.O3	EV charging scheduled to off-peak during the night in order to reduce or mitigate a possible network upgrade based on either dual-tariff approach (the least cost) or on intelligence system with 2-way communication for time slot with override capability way of control (the most expensive)[16]
Smart.O3.VC	Same as Smart.O3 but with the implemented voltage control on LV network
Smart.O4	Same as Smart.O3 but with the locally optimised control of EV charging; the following sub scenarios are considered: Smart.25 – 25% penetration of smart charging (O4) and the remaining O2 Smart.50 – 50% penetration of smart charging (O4) and the remaining O2 Smart.75 – 75% penetration of smart charging (O4) and the remaining O2 Smart.O4 – 100% penetration of smart charging (O4)
Smart.O4.VC	Same as Smart.O4 but with the implemented voltage control on LV network

Figure 2.12 shows the cumulative network reinforcement cost for various charging scenarios following the example EV uptake scenario depicted in Figure 2.9. For the majority of scenarios the annual reinforcement cost increases in time and reaches its maximum at about 2040. In the BaU scenario the maximum annual cost is just above €0.5bn/pa (right). The total reinforcement cost by 2050 for the BaU case amounts to €9.5bn, while for Smart.O4 it is zero (left). This illustrates that the magnitude of the effect of controlled EV charging is potentially very significant.

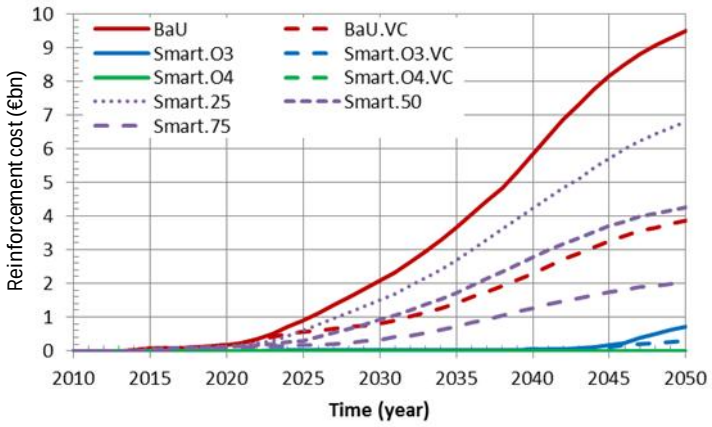


Figure 2.12 Evolution of cumulative reinforcement cost for various charging scenarios for the assumed EV uptake case

[16] We should point out that simple static time-of-use tariff control in its basic format may not be appropriate for EVs as establishing fixed schedules for charging of individual EVs may significantly limit their use and hence intelligence system with 2-way communication may be required. On the other hand the application of O3 with override function or a simple static tariff may not be sufficient for mitigating overloads in distribution networks. Hence, achieving effective overnight charging may turn out to require similar intelligence as full smart charging (O4).

Figure 2.13 shows the net present value (NPV) for various charging scenarios due to the assumed increase in EV uptake. The numbers presented in the figure include not only the network reinforcement cost, but also the cost of intelligence i.e. of installing the necessary ICT infrastructure to enable EV charging control. The charging scenario with the lowest overall cost is Smart.O3m.VC voluntary option (about €0.1bn). However, Smart.O3.VC 2-way communication option is in the range with Smart.O4 option (about €0.4bn). This clearly demonstrate the benefits of controlled charging (O3 and O4).

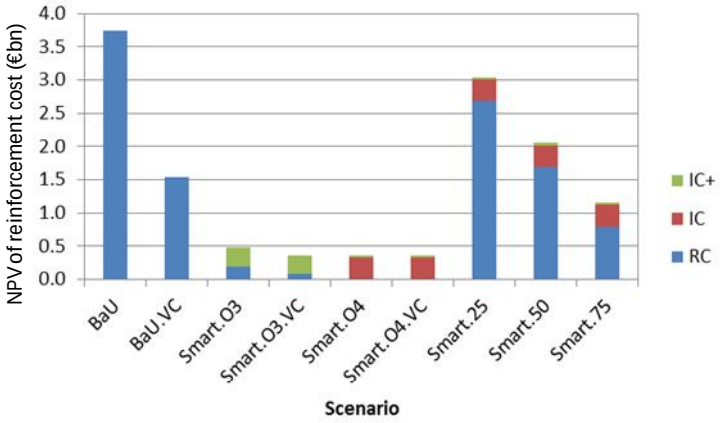


Figure 2.13 NPV for various charging scenarios (RC – reinforcement cost, IC – low-end cost of intelligence, IC+ – additional cost high-end intelligence)

The analysis suggests that a significant portion of distribution network reinforcement costs driven by EV integration can be mitigated by intelligent charging and/or local voltage control, and that these measures provide cost-effective solutions to efficient integration of new demand in distribution networks. The following specific observations can be made:

- Investment in intelligence to mitigate network reinforcement is the most cost-effective solution across all scenarios.
- Specifically for low EV uptakes, it would be cost-effective to deploy intelligence to facilitate off-peak (i.e. overnight) EV charging, to complement the national demand profile.
- For higher EV uptakes, the investment in full smart functionality of intelligent infrastructure that would optimise EV charging with respect to the local network loading conditions would be cost-effective.
- In addition to the investment in intelligence, deployment of in-line voltage regulators is clearly justified in case of electrification of transport (and heat) sectors.

2.5 Reinforcement calculations using ITRES tool

As part of its work in Green eMotion, Imperial College London has developed ITRES, a software tool for assessing reinforcements of LV distribution networks driven by electric vehicles. The tool has been designed to quantify the impact of a significant uptake of electric vehicles (EVs) on the need for reinforcements in a specific LV distribution network, and

hence to facilitate the network planning process in the context of accommodating a high number of EVs. The reinforcement needs are quantified over the time-horizon of up to 25 years, with the possibility to consider alternative EV charging strategies. The key purpose of the tool is to enable the analysis of the impact of different EV uptake levels and charging policies on the local LV distribution network, particularly in the Green eMotion demo-regions. Furthermore, ITRES also enables the benefits of alternative smart charging policies to be evaluated on specific LV networks.

In this section we only present the key capabilities and concepts of network reinforcement calculations performed in ITRES, while more details on the tool and the case studies performed on LV networks in various European countries can be found in previous D4.3 reports.[17] Key capabilities of ITRES are demonstrated on the example of a simple generic LV distribution network with 65 nodes, as illustrated in Figure 2.14 (left). Figure 2.14 (right) also shows the assumed evolution of the peak demand and the number of EVs connected to the network.

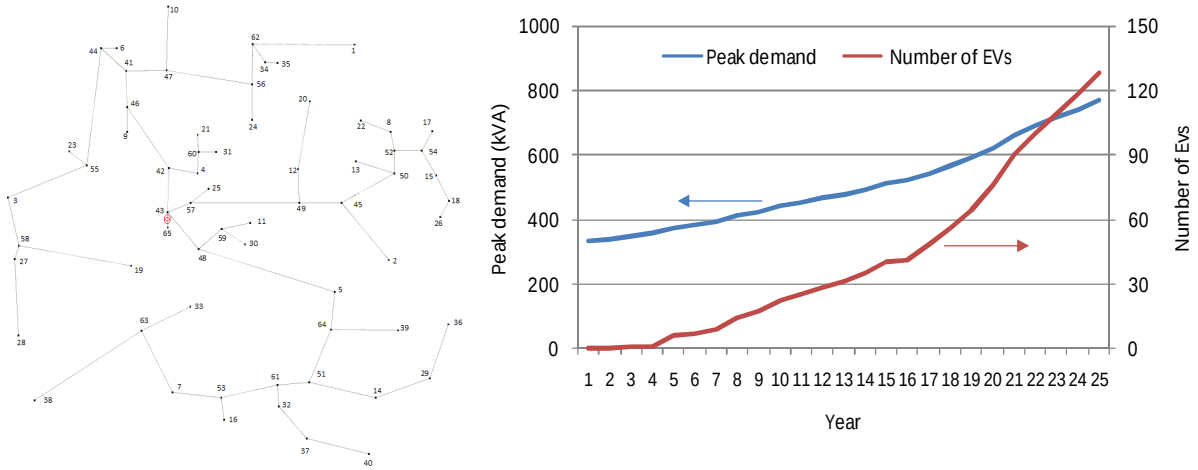


Figure 2.14 Example network configuration and projected peak demand and EV number growth

ITRES detects if there are violations of thermal and voltage constraints in the specified LV network, and if necessary selects and implements appropriate network reinforcements. Key outputs of the analysis include:

- Volumes (capacities) of voltage-driven network reinforcements in each year
- Volumes (capacities) of thermally driven network reinforcements in each year
- Cost of network reinforcements in each year

For the assumed distribution network, the reinforcement schedule calculated by ITRES is illustrated in Figure 2.15, which quantifies the cost of necessary network reinforcements during the study period, disaggregated with respect to the asset type and reinforcement driver (voltage or thermal constraint). For instance, UG-I denotes the reinforcement of underground cables due to thermal violations, while UG-V refers to cable reinforcements

[17] Reinforcement calculations are presented in Deliverable 4.3-B2 “Electric Vehicles and Grid: Reinforcement Costs in Low Voltage Grids”, while the description of the ITRES tool is provided in Deliverable 4.3-C1 “ITRES: Tool for assessing the technical and economic impact of electric vehicles on distribution networks – User Manual”.

driven by voltage constraints. In a similar manner, OH-I and OH-V refer to overhead line reinforcements. GMT and PMT refer to Ground- and Pole-Mounted Transformers, respectively. The reinforcement costs are presented as discrete investments occurring in individual years over the study period, taking into account the investments taking place in previous years.

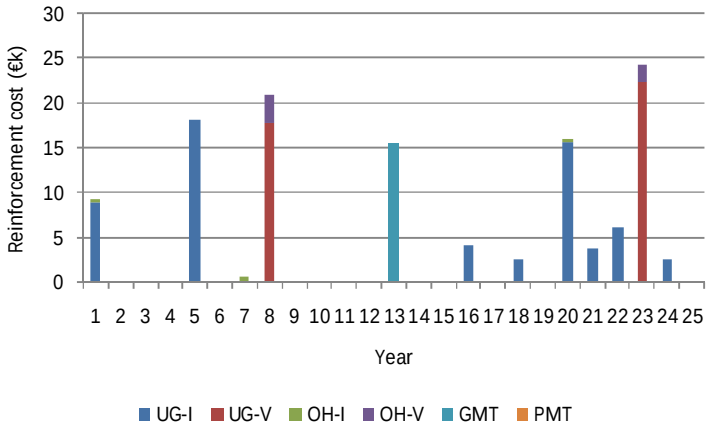


Figure 2.15 Reinforcement cost components calculated using ITRES tool

It can be observed from the figure that the bulk of the cost needed to accommodate increasing EV demand is associated with underground cable replacements, both due to thermal and voltage constraints. The distribution transformer (GMT) also needs replacing around the middle of the study period.

A further example is used to illustrate some of the findings from the Deliverable 4.3 – B2 report ("Electric Vehicles and Grid: Reinforcement Costs in Low Voltage Grids"), where a number of actual LV distribution networks in Denmark, Italy and Spain have been analysed using the ITRES tool with respect to the ability to accommodate EVs, i.e. the necessity to reinforce the networks in order to supply the additional EV demand.[18] The example quantifies the impact of different EV penetration scenarios (low, medium and high) on the necessary reinforcement in a selected Danish LV network.

Figure 2.16 shows the reinforcement schedule for the selected network under low, medium and high EV penetration, and based on the assumption of user-dependent (i.e. uncontrolled) charging. In the low penetration case the reinforcements only occur towards the very end of the study period. Increasing the EV penetration to medium and high levels results in significantly higher amount of reinforcement, which also takes place much earlier in the study period.

[18] J. Mehmedalic, J. Rasmussen, S. Harbo, "Electric Vehicles and Grid: Reinforcement Costs in Low Voltage Grids", Deliverable 4.3-B2, June 2013.

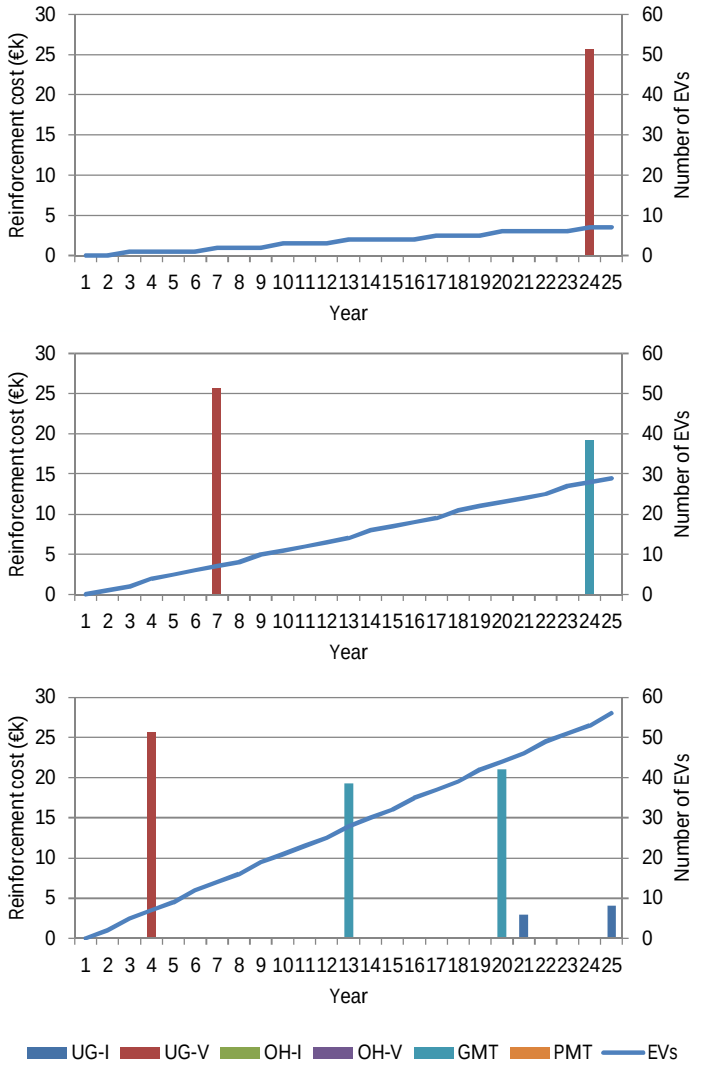


Figure 2.16 Reinforcement schedules for a Danish LV network with low (top), medium/baseline (middle) and high (bottom) EV penetration and user dependent charging

The report further concluded that if alternative, system-led charging control strategies are adopted, the cost of reinforcing the network drops, and is also postponed compared to the uncontrolled case. This is especially the case with the load-dependent charging, where EV demand profile is modified to minimise the total peak demand in the distribution network.

2.6 Coordinated planning of network and charging infrastructure

Another feature not included in present distribution planning tools is the ability to integrate network planning with the planning of EV charging infrastructure. The network of public or private charging points in a given area will have an obvious impact on the requirements for distribution network capacity. Its locations will be driven by transport and other infrastructure in the built environment (public buildings, parking lots, commercial centres etc.), as well as by users' behavioural and mobility patterns. In the context of rapidly increasing penetration of electrified road transport, it will become critical that distribution network planning tools take into consideration specific aspects relevant to planning charging infrastructure that have not

been a part of traditional planning tools. A coordinated approach to planning network and charging infrastructure is needed in order to minimise the overall cost.

2.7 Implications for future distribution network planning and functionality of future planning tools

This section presented several examples of using the flexibility of responsive EV demand to ensure a more efficient operation of and investment into distribution assets, and outlined the potential benefits of integrating smart meter-enabled EV demand, with appropriate functionality and communication systems, into real-time distribution network control. We demonstrated that this approach may reduce network reinforcements significantly through deploying optimal EV charging strategies and future distribution network planning tools will need to incorporate these new approaches to network management. Clearly, under the 'Smart' operation paradigm, which optimises EV charging in real time to minimise the impact on the network, any constraints associated with EV demand flexibility will need to be incorporated in the future distribution network planning framework, including the risk and cost associated with the supporting ICT infrastructure.

3 Alternative LV network reinforcement strategies

Traditional network-based solutions for distribution network reinforcement focus on replacing or upgrading existing network components, in particular transformers and lines. Many planning tools therefore adopt an approach where if a voltage or thermal issue is detected or forecasted for any of the components, this component is replaced by the one with a higher rating, although it may be more efficient to insert additional substations and hence reduce feeder length where feasible and appropriate given the planning issues. In that context, this section considers two alternative reinforcement strategies and compares how they perform in terms of the reinforcement cost incurred. The examples demonstrate the merit of including alternative LV network reinforcement strategies into future distribution planning tools, as opposed to a simple replacement of components. Alternative strategies may therefore be needed in future planning tools to ensure that the least-cost strategy has been identified while considering practical network constraints, especially in the context of a rapid electrification of road transport.

Most distribution network studies find that a very significant proportion of the total reinforcement cost is driven by loads either exceeding LV feeder thermal ratings or giving rise to voltage variations outside statutory limits. In that respect, two alternative reinforcement strategies can be formulated: (i) reinforcing overloaded feeder sections while maintaining the number of distribution substations constant (*like-for-like* replacement); and (ii) inserting additional distribution substations in order to reduce the lengths of LV feeders (*network splitting*) and hence eliminate overloads and inadequate voltages, while reducing the need to reinforce LV feeder sections. It is generally considered that these two reinforcement policies would provide the boundaries on network reinforcement costs likely to be incurred in practice.

The two reinforcement strategies can become even more significant in the context of distribution network asset replacements that would need to be carried out due to aging of equipment. Clearly, there might be an opportunity to take advantage of any need for non-load related (i.e. condition-based) asset replacement, and rather than adopting a like-with-like replacement approach, it might be appropriate to strategically install assets of higher capacity in anticipation of the higher network loading driven by electrification of the heat and transport sectors.

A significant proportion of network reinforcement cost, particularly in semi-urban/rural and rural networks, is driven by voltage constraints. This suggests there are considerable opportunities for reducing network reinforcements through introducing LV voltage control facilities such as in-line voltage regulators or distribution transformers with an on-line tap changing capability.

3.1 Impact of voltage drop limits and active LV network voltage control

The example shown in Figure 3.1 illustrates the percentage of LV feeder lengths that would need reinforcement for different levels of voltage constraints under a BaU and a Smart mode of network operation for 50% of EV penetration in a representative semi-urban/rural network.[19] For the statutory voltage drop limit of 6%,[20] the proportion of voltage driven

[19] Smart operation assumes that EV charging is controlled to minimise network reinforcement, while respecting the requirements of vehicle users.
[20] The allowed voltage drop limit in other jurisdictions may be different. A drop limit of 10% is commonly found.

network reinforcement is about 5 times higher than thermal driven reinforcement. If the introduction of smart LV voltage control (through the application on in-line voltage regulators or OLTC transformers) is simulated by relaxing the voltage limit constraint to say 10%, the percentage of feeder length reinforcement driven by voltage constraint decreases substantially. As expected, the need for feeder reinforcement under the Smart operating regime is significantly lower than for the BaU mode of operation.

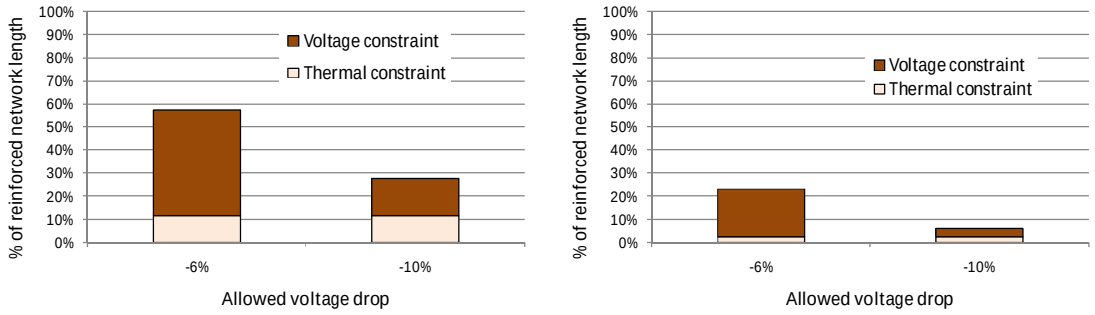


Figure 3.1 Percentage of reinforced LV feeder length for BaU (left) and Smart (right) for different voltage limit constraints (50% EV penetration)

As expected, savings from relaxing voltage drop limits or installing LV voltage control facilities are lower when the penetration of EVs increases to 100%, as indicated in Figure 3.2. However, real-time LV voltage control in combination with real-time demand response supported by appropriate functionality of smart metering, can avoid reinforcements for a significant proportion of the LV network.

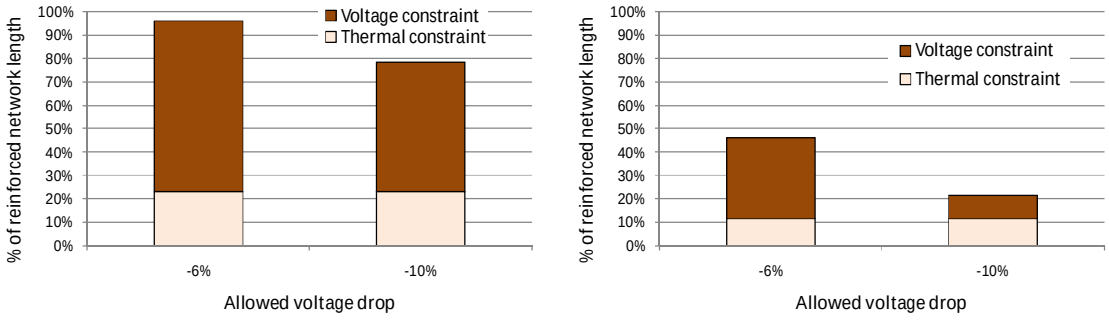


Figure 3.2 Percentage of reinforced LV cable length for BaU (left) and Smart (right) for different voltage limit constraints (100% EV penetration)

3.2 Comparing like-with-like asset replacement with network splitting

Given that the distribution network reinforcement cost, driven by the uptake of EVs and potentially also other types of new demand (such as heating), is dominated by LV network reinforcement, it can be beneficial to implement an alternative network replacement strategy that involves inserting additional distribution network transformers and splitting the existing LV network.

From Figure 3.3, which refers to the same network as the one used to produce Figure 3.1, it can be observed that the potential financial benefits of this replacement policy are very significant. The overall reinforcement scheme costs as a result of inserting additional distribution transformers with accompanying switchgear would normally be significantly

lower, amounting in this particular case to about one third of the cost of replacing existing transformers (with higher capacity units) and overlaying LV feeders. It needs to be mentioned however that this option may not be available in all circumstances due to various physical constraints that may limit building new substations. The actual reinforcement policy that could be realistically pursued would therefore expectedly be found in the space between the like-for-like and the network splitting strategy.

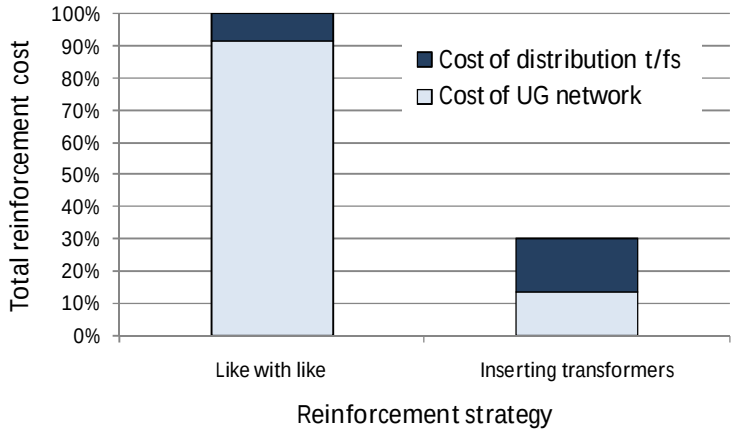


Figure 3.3 Total LV network reinforcement cost for reinforcement strategies (100% EV penetration)

3.3 Implications for future distribution network planning and functionality of future planning tools

Current distribution planning tools do not question the appropriateness of the currently used voltage levels, nor whether the existing network design philosophy is appropriate for the future (as illustrated in above examples, it may be appropriate to change the density of the distribution substations, which would change the feeder length). Ignoring these effects could potentially increase the network reinforcement cost as demonstrated in above examples, particularly in the context of widespread EV deployment. The current network design philosophy, which has been introduced at the end of 1950's may not necessarily be optimal for 21st century systems. Future distribution network planning tools will therefore need to cater for the possibility for adopting innovative network designs such as alternative replacement strategies, shift to new voltage levels etc.

4 Distribution network constraints and wider system considerations

As discussed in Section 2, the envisaged significant increase in demand and the extensive deployment of distributed renewable and low-carbon generation and demand technologies are expected to impose additional stress on distribution networks. Efficient distribution system planning tools hence require a good understanding of the associated technical and economic impacts in the future.

This chapter discusses the distribution network constraints that are most relevant to consider when accommodating the new EV-driven demand into network planning. It also discusses potential synergies and conflicts between the use of smart grid solutions such as flexible EV charging for local network management and the application of these solutions to address the operation of the wider electricity system, such as e.g. supporting the integration of intermittent renewable generation. A short discussion on the reliability considerations as well as the recent update of network planning standards in the UK is also provided, with more details included in Appendix 2.

4.1 Local network considerations

The following types of network constraints merit particular attention in the context of accelerated deployment of EVs in distribution networks:

- Voltage, thermal and fault level limits
- Losses
- Reactive power management
- Bidirectional flows and their effect on protection schemes
- Power quality

Performance and condition of demand and generation equipment are highly sensitive to the voltage amplitude. Voltage variation therefore should be in an acceptable range, typically -5% (-10%) to +5 (10%). As a result of dense load or DG connections in specific parts of the network, the voltage may breach these limits, especially across long LV distribution feeders in semi-rural and rural areas. On the other hand, urban networks are expected to face thermal problems, driven by significant connection of low carbon demand technologies (EV and/or HP) and fault level problems driven by DG connection. It is important to bear in mind that in the longer term voltage and border power quality constraints and requirements may change.

The envisaged electrification of transport and heat sectors and the widespread integration of DG will most likely result in a significant increase in power flows in both directions. Under the traditional (passive) distribution network operation regime, network reinforcement would be inevitable to relieve the resulting congestion issues. In this conventional distribution network operation paradigm, voltage and congestion problems are addressed by appropriate network reinforcements. This may be characterised by significant reinforcement costs and result in low utilisation of distribution assets.

As discussed in Section 2, active management approaches with real-time control of different components could alter this paradigm and lead to lower reinforcement costs and higher network utilisation. However, the latter may be accompanied by an increase in network losses. In these terms, the significance of including the economic value of losses in the

optimal distribution planning should be revisited and the shaping of this trade-off by the inclusion of different active measures should be analysed.

The impact of reactive power on distribution networks is not as significant as in transmission networks due to the lower reactance to resistance ratio. Nevertheless, suitable reactive power management strategies should be employed by the DSO, especially with respect to the network losses, which may be very significant.

In contrast to the conventional distribution network operation regime, where power only flows from the transmission system towards end-consumers, future networks will also encounter bidirectional flows due to the deployment of DG. The worst case associated with these reverse flows in terms of distribution stress, occurs when the DG production is at its maximum while the local demand is at its minimum. This effect of bidirectional flows will also affect the effectiveness of distribution protection schemes, which have thus far only considered unidirectional flows.

Power quality constitutes another significant aspect associated with the planning and operation of distribution networks. Power quality includes a large number of parameters reflecting the characteristics of supplied power to the consumers, such as harmonics, continuity of services and transient voltages and currents and it has been studied in depth in the context of traditional distribution networks. However, the introduction of new technologies in future networks will create challenges which have not been experienced before. Power electronic interfaces of DG, the EV charging infrastructure and network control devices will inject additional harmonics into the network and will generate additional transients during dynamic disturbances. Approaches to address these challenges need to be coupled with traditional power quality measures. This issue has been addressed in the D4.3 A1 report on the impact of EVs on harmonics in distribution networks.

4.2 Interaction between distribution network and wider electricity system

In addition to using flexible demand such as EVs to reduce peak loads and consequently improve network capacity utilisation, it may also be desirable for demand to respond to opportunities in the energy, reserve and ancillary services markets. Demand response could be optimised to maximise the commercial benefits when exposed to time-varying energy prices, which would entail shifting significant demand volumes to periods with abundant renewable generation output (e.g. wind or solar) and therefore lower electricity prices. In a potential future situation where high wind and/or solar generation output coincides with system peak demand, much of EV charging incentivised by low prices would be shifted towards the time around system peak to make full use of available wind energy. With a large number of EVs being charged during peak hours (driven by supply price signals) the stress on the distribution networks may become significant, resulting in a much higher proportion of overloaded feeders and transformers (and hence higher reinforcement cost) than in the case where EV charging is controlled with the objective to support the local distribution network. This simple example illustrates that independent operation of the electricity market (i.e. continuing with an “unconstrained” trading philosophy) without due consideration of distribution network limitations will potentially be suboptimal in terms of the overall efficiency (and therefore cost) of the end-to-end electricity delivery chain.

The challenge for future tools is therefore to enable a coordinated assessment of both supply and network businesses in order to avoid conflict between local management and national system conditions. Present network planning tools do not consider this interaction. Future distribution planning tools will need to somehow take into consideration wider system

implications i.e. respect cost and benefits at both national and local levels. Of particular relevance for flexible EV demand is the capability to e.g. provide ancillary services or participate in V2G schemes to support the wider system, which may create both conflicts and synergies with respect to the requirements of the local distribution network. The model developed by Imperial in D9.2 of Green eMotion will be used to illustrate the whole-system impact of large-scale EV uptake on European electricity system by including both network and supply considerations in system analysis, i.e. by finding optimal trade-offs between supporting the two different segments of the system.

Figure 4.1 presents an illustrative example of how the system benefits of smart EV charging are allocated across the system for different assumptions on distribution network cost level.[21] The example demonstrates that the utilisation of flexible EV demand to avoid distribution network reinforcement cost is a function of the reinforcement cost level of the specific network, as well as the opportunities to generate cost savings in other segments of the electricity system.

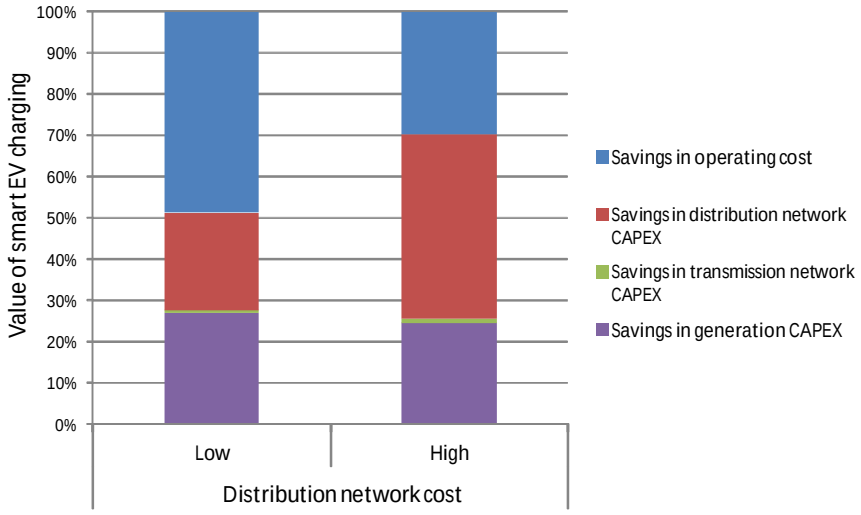


Figure 4.1 Split benefits of smart EV charging for different levels of distribution network cost

In case when the cost of reinforcing the distribution network is low (such as e.g. in networks characterised by overhead lines rather than underground cables), EVs are used less to avoid distribution reinforcement (accounting for about 25% of the cost savings) and more to reduce operating cost, primarily through supporting the integration of intermittent renewable generation (about 50% of the total savings). The remaining part of system benefit is associated with savings in generation capacity cost needed to ensure sufficient levels of security of supply. If on the other hand EVs are located in a distribution network with high reinforcement cost (such as e.g. networks with long cable lengths), the optimal whole-system strategy of using flexible EVs shifts more towards avoiding network reinforcement (about 45% of the total benefit), and forgoes a considerable part of the operating cost savings, which now reduce to about 30%.

[21] The values have been obtained from a preliminary analysis of the impact of electromobility on the electricity system using Imperial's whole-system assessment model developed in D9.2. The numbers depicted are for the UK system in 2030.

This example illustrates how the most cost-efficient usage of flexible EV resource adapts to the savings opportunities across the system, which can result in markedly different drivers for savings in distribution reinforcement cost. Future network planning tools need to be able to take this effect into account, rather than evaluate flexible EV demand or other non-network solution in isolation from the rest of the system, given that minimising only the network cost may not deliver an overall optimum.

Another example based on the analysis carried out in D9.2 of Green eMotion, which carries out the whole-systems assessment of high EV penetrations, depicts the potential savings from controlled EV charging in the assumed 2030 systems of Germany and Spain, as illustrated in Figure 4.2. Following the whole-system approach of D9.2, the benefits are quantified for different sectors of the electricity system (operating cost, and investment cost into generation, transmission and distribution infrastructure), and are expressed as annual monetary values per vehicle for varying shares of national EV fleets participating in smart charging schemes (between 25% and 100%). Although the exact split between benefits generated in different sectors varies depending on the particular system, we typically observe that controlled EV charging brings multiple system benefits simultaneously, i.e. that the same EV resource can be used for more efficient system balancing as well as avoiding investments into generation, transmission and distribution infrastructure.

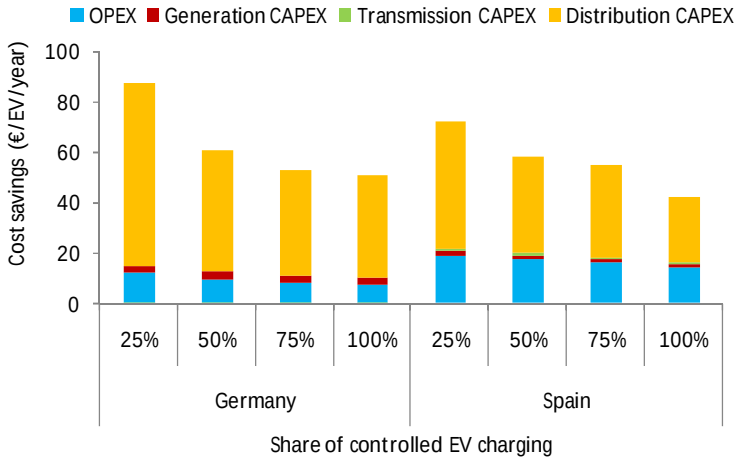


Figure 4.2 Whole-system benefits of controlled EV charging in German and Spanish systems in 2030

4.3 Implications for future distribution network planning and functionality of future planning tools

Future network planning tools will need to incorporate a range of established distribution network constraints, but will also have to accommodate the improved information on local network conditions provided by advanced technologies such as Dynamic Line Rating or Condition Monitoring. This will enable the planner to have more precise information available on realistic network conditions, thus ensuring adequate utilisation of network capacity.

On the other hand, in order to achieve efficient operation and planning from the whole-system perspective, future network planning tools will have to be able to include the interaction with other segments in the electricity supply chain, in particular with the objective to ensure an efficient integration of output supplied by intermittent renewable generation. The interaction with the telecommunication infrastructure will also need to be taken into account.

Future network planning tools should assist in deriving optimal investment strategies for distribution network reliability enhancement via explicitly assessing and optimising network reliability performance seen by end consumers, and this should include fault management optimisation through optimally locating fault breaking devices, fault detection equipment and fault response processes so that the reliability performance of the network is optimised whilst considering the cost of these measures.

The conceptual framework outlined in this section could be used to quantify the security contribution of other non-network solutions such as flexible EV demand, while considering their specific operating constraints, such as the energy requirements and the flexibility to shift demand in time. Furthermore, future network planning tools will need to accommodate the reliability performance of the ICT infrastructure that will be essential for future network operation as the present planning tools do not consider ICT explicitly in distribution reliability assessment.

5 New conceptual framework for planning future distribution networks

In light of the expected challenges that future distribution network are expected to face, a fundamental overview of the network planning methodology will be required in order to ensure that the distribution service is delivered at efficient cost. This section therefore discusses the concepts of how the current planning tools should be enhanced, not only to ensure an efficient integration of EVs, but also to respond to other challenges and opportunities, such as the integration of DG, storage, flexible demand as well as the utilisation of advanced smart grid technologies and solutions.

5.1 Incorporating enhancements of real-time distribution network management into network planning

In order to ensure the maximum cost-efficiency of distribution planning, a link will need to be established between the active distribution network operation solutions (which may include various levels of EV charging management) and the distribution network planning activity. It is now widely understood that active network management may require significantly less distribution network reinforcement, in particular when accommodating new transport and heat demand. Future distribution planning tools need to be able to adequately take into consideration this link between smart network operation and lower requirements for asset redundancy, while giving full consideration to the risk profiles of smart solutions, in particular the ICT infrastructure.

Advanced technologies and technical solutions such as voltage regulators, network reconfiguration, dynamic line rating, phase balancing, reactive power compensation, demand-side response, and ancillary services including frequency regulation and emergency response can be used to mitigate the problems associated with network constraints (discussed in Chapter 3) and hence impact distribution network planning. The technology and software enhancement in real-time Distribution Management Systems will be needed to support the Smart Grid paradigm, which will also radically change future distribution network planning. Novel ICT solutions are expected to bring new functionalities, but need to be properly understood in terms of the implications for the network risk profile.

5.1.1 Advanced network control technologies

In order to address voltage constraints, several new network control technologies have been introduced recently:

- In-line voltage regulators
- Solid-state on-load tap-changing transformers
- Area-based coordinated voltage control
- Soft Normally Open Points
- Dynamic Line Rating

In-line voltage regulators provide continuous regulation of voltage amplitude in real time. Compared to power factor correction, where shunt capacitors are used to inject reactive power, inline voltage regulators are more efficient in terms of network losses. With respect to on-load tap changers, voltage regulators take considerably less time to install, and are also less expensive.

Another technology with a wide-scale potential is solid-state transformers. They are able to deliver high power, e.g. 1 MW, at high frequency, e.g. 20 kHz. As a result, they are light, small and more efficient in terms of losses. Finally, there has also been a significant interest for using area-based voltage control instead of local-based voltage control at MV levels.

In the event of fault in the distribution network, largely at MV and HV levels, network reconfiguration measures can retain continuous supply to consumers. Network reconfiguration can also be used for maintenance and refurbishment.

New distribution network planning tools will also need to incorporate emerging distribution network technologies such as power electronics-based Soft Normally Open Points (SNOPs), which can be used to manage power flows in distribution networks.[22]

With Dynamic Line Rating (DLR), the effects of changing weather conditions such as wind speed and direction, solar radiation, and ambient temperature, on the thermal capacity of lines are taken into account in real time. While the concept of DLR has gained some recognition in transmission networks, demonstration projects are also carried out to consider dynamic line rating applications in distribution systems.[23]

Apart from purely network control solutions, the potential of flexible demand (such as controllable EV charging) and DG controllability for mitigating distribution network issues has attained increasingly significant interest. A large number of research projects have been initiated in recent years focusing on the potential roles of demand-side management in distribution network operation and planning. Their main objective is to exploit the flexibility of different demand technologies in order to mitigate voltage and thermal constraints. In this respect, demand-side response can contribute to more efficient operation and investment in distribution network. Furthermore, there are currently several research and demonstration projects dedicated to grid-scale storage in the LV, MV and HV distribution networks.

Real-time controllability of DG can also address similar network problems. Particular interest is given to curtailment actions triggered by the DSO and power factor control. Key challenge in accounting for these non-network solutions in future planning tools lies in the establishment of novel commercial arrangements for the interaction of the owners of these technologies with the DSO, such as non-firm connection of DG or dynamic pricing schemes for flexible loads.

5.1.2 Active operation of distribution networks

Today's distribution systems have been designed to accept bulk power from the transmission network and to distribute it to customers, with the predominant flow of both active and reactive power from higher to lower voltage levels. The behaviour of the network in this

[22] SNOPs use power electronic devices which enable that the benefits of both radial and meshed systems are achieved. This hybrid system type allows for supporting isolated load on a feeder, improved voltage regulation, precise control of real power flows between feeders and improved load balancing, as well as isolating disturbances and faults between the feeders as in a radial system. For more information see e.g. http://www.hubnet.org.uk/filebyid/33/SOP.pdf.

[23] Dynamic Line Rating is one of the key technological innovation areas for distribution networks recognised by the EEGI Roadmap 2013-2022.

context is rather well understood and the procedures for both design and operation have been established for a long time.

However, with significant penetration of flexible EV loads, demand-side response, distributed generation or distributed storage (often referred to as Distributed Energy Resources or DERs) the power flows may become reversed, resulting in the distribution network no longer being a passive circuit supplying loads but an active system with power flows and voltages determined by the generation as well as the loads.

The change in active and reactive power flows caused by DERs has important technical and economic implications for the power system. To date, most attention has been paid to the immediate technical issues of connecting and operating generation on a distribution system and most countries have developed standards and practices to deal with these. In general, the approach adopted has been to ensure that any DER does not reduce the quality of supply offered to other customers and to consider the generators as “negative load”. No real attempt has been made to consider how the overall performance of a distribution system with a significant penetration of DERs with smart grid capability may be optimised.

In present circumstances for instance, the objective of a distributed generator is to supply the maximum energy (kWh) to the network and thus receive the maximum possible payment through a pre-defined tariff. The objective of the DSO on the other hand is to maintain supply to all customers, the majority of whom will be load customers. As the DSO has no control over the distributed generator, all decisions concerning the network must be made considering the worst possible conditions of the generation for any set of network conditions. Hence at minimum (or even zero) load the maximum generation is assumed and at maximum load, minimum generation is assumed. There is currently very limited scope to optimise the overall operation of the distribution network and the embedded DERs.

The requirement to maintain voltages within statutory limits is an important driver for designing the distribution network. Various techniques have been developed over the years to maximise the utilisation of distribution circuits when supplying the customers within the required voltages (e.g. the ratio of the MV/LV transformer is usually adjusted so that at times of maximum load the most remote customer receives acceptable voltage; during minimum load the voltage received by the customers closest to the transformer is just below the maximum allowed). If a DER is now connected to the end of a circuit, the flows and voltage profiles in the circuit will change.

In some cases, the voltage rise can be mitigated by reversing the flow of reactive power either by using an induction generator or by under-exciting a synchronous machine and operating at a leading power factor. This can be effective on higher voltage overhead circuits, which tend to have a higher X/R ratio. However, the LV cable distribution circuits are dominated by active power and network resistance, and only very small DERs may generally be connected to LV networks.

As the present network operation philosophy is known to considerably limit the amount of DERs that can be connected, there is a need to adopt more active approaches to network operation, by effectively changing the conventional operational doctrine for distribution networks from passive to active. Various degrees of integration are possible, ranging from a simple local-based DER control to a coordinated control between distribution facilities and DERs over interconnected distribution circuits. This co-ordinated, system-level voltage and

flow control could be based on an advanced controller that allows this integrated operation to be implemented.

The controls may be implemented either using central Distribution Management System controllers, such as one depicted in Figure 5.1 (say one for each 33/11 kV substation), or by distributing the control functions among the various controllers associated with each item of plant (i.e. DER actions, tap changers); this choice is largely an issue of implementation. The required control actions are slow (e.g. change of tap changer set-point or DER active and reactive power dispatch), so low-cost, slow communication systems will be appropriate. The overall control system should be arranged in a hierarchy with the controllers of the 33/11 kV substations communicating upwards to similar equipment in 132/33 kV substations etc. and the higher-level DSO control systems.

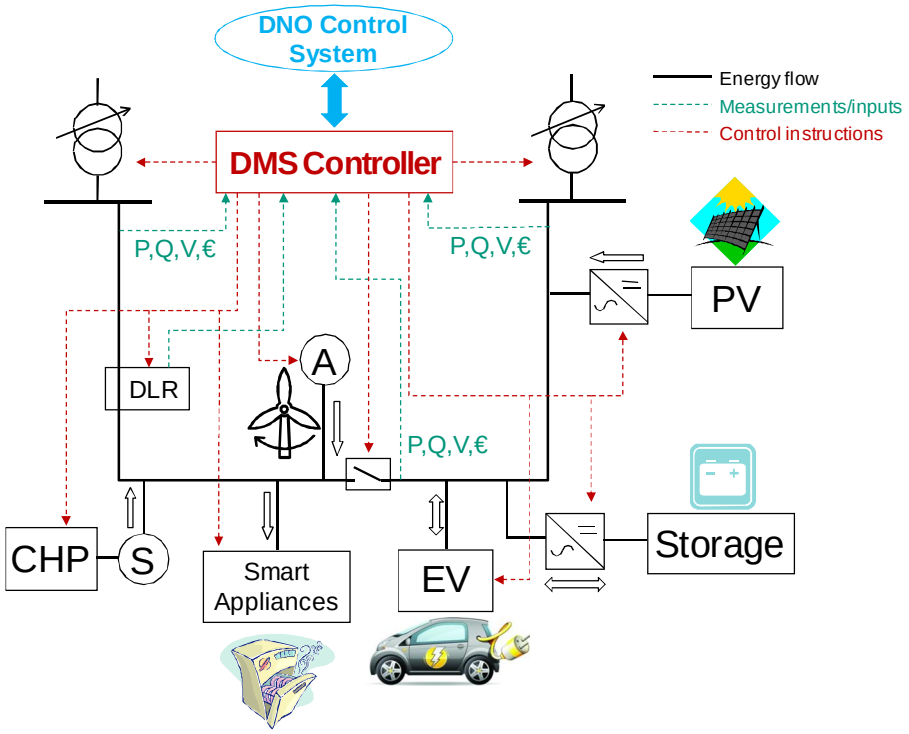


Figure 5.1 Active distribution network operation

In the example in Figure 5.1, the CHP generator with a synchronous machine (S) will export active power when the electrical load of the premises falls below the output of the generator but may absorb or export reactive power depending on the setting of the excitation system of the generator. The wind turbine will export active power but is likely to absorb reactive power as its induction (sometimes known as asynchronous) generator (A) requires a source of reactive power to operate. The voltage source converter of the photovoltaic (PV) system or storage will allow the export of active power at a set power factor but may introduce harmonic currents. DMS controller can also schedule various types of flexible demand, such as Electric Vehicles or Smart Appliances, based on the flexibility offered by these customers.

In addition to basic electrical measurements such as voltage or power, the advanced network control functionalities, such as Dynamic Line Rating (DLR) will require that additional information such as weather data is provided to the DMS controller. The controller would also be capable of altering the network topology such as controlling the Normally Open Points in

response to interruptions to normal supply conditions, through its Post-Fault Reconfiguration functionality.

DMS Controller in the above example takes the following information as inputs: (i) measurements for network flows and voltages (P, Q, V), (ii) contract costs for constraining generation on and off (€), and (iii) network topology i.e. the states of switches in the network. Its architecture is illustrated in Figure 5.2. Where there are no local measurements available, the network conditions are assessed using the controller's State Estimation module. Control instructions issued by the DMS controller include: transformer tap positions, DER schedules (P, Q), voltage control actions and switching actions.

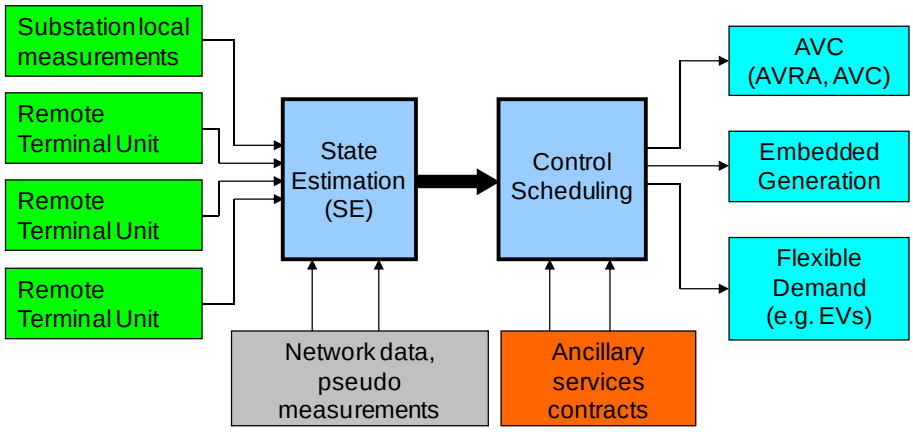


Figure 5.2 Architecture of DMS controller in active distribution networks

Active management of distribution networks could generate significant savings in network cost when accommodating new types of load and distributed generation. Although the cost associated with the operation of active distribution networks needs to be quantified, it is expected that the benefits will considerably outweigh the cost of its implementation. At present, however, most DSOs do not have strong incentives to offer active management services. In order to support the development of active distribution networks and extract corresponding benefits associated with connecting increased amount of embedded generation, new commercial arrangements will need to be developed that incentivise DSOs to adopt active operation solutions as opposed to traditional, largely passive approach.

Furthermore, a link should be established between the active network operation solutions and schemes and the network planning activity. It is evident that active network management may require significantly less reinforcement to accommodate new demand as the result of heat and transport electrification. Future distribution planning tools need to be able to adequately take into consideration this link between smart network operation and lower requirements for asset redundancy. In doing so, it will be critical to understand the risk profile of smart solutions, in particular the ICT infrastructure, in order to assess to what extent the advanced solutions can be relied upon in network planning, and what that means for network assets. In this respect, the EEGI Roadmap has also emphasised the necessity to include appropriate levels of operational control balanced against planning measures in DSO planning and operation practices.[24]

[24] European Electricity Grid Initiative, "Research and Innovation Roadmap 2013-2022", January 2013. Available at: http://www.gridplus.eu/eegi.

5.1.3 Demand-side response and storage applications

The objective to improve distribution asset utilisation levels in the context of high penetrations of both intermittent renewable sources and electrified transport and heat demand is likely to require a fundamental shift from a passive to an active philosophy of network operation. This shift can be enabled by the incorporation of various types of flexible demand and energy storage into system operation and design, facilitated by the application of smart metering supported by an appropriate information, communication and control infrastructure.

Specific examples of using the flexibility of responsive demand and energy storage to ensure a more efficient investment into distribution assets are presented in Appendix 1. By integrating smart meters with appropriate functionality and communication systems into real-time distribution network control, it is expected that the need for network reinforcement may be significantly reduced, through locally optimising the actions of various types of responsive demand and storage.

The key consideration with respect to demand-side response is that it is not possible to use its flexibility without understanding how particular consumer devices operate. Traditional network planning has treated demand as a fixed input variable (with its power and energy stated explicitly in MW and MWh). If demand-side flexibility is to be incorporated and characterized in distribution network planning tools, it is necessary to have an understanding of which specific services this particular power and energy are being used for. That requires a comprehensive description of the way electricity is being used by the end customers in order to quantify their capability to redistribute their electricity consumption across time.

5.1.4 Coordinated voltage control in distribution networks with distributed renewable generators

Impact of large penetrations of distributed renewable generators (such as photovoltaic panels (PV) or distributed wind generation) on distribution network needs to be properly understood and quantified. In this context, Figure 5.3 illustrates the total distribution network reinforcement cost for the whole EU with increasing PV penetration. For relatively small PV penetration levels, of up to 8%, the additional reinforcement costs lay in a narrow range of around €1.6-2bn. The reason for this is that the network is well designed and does not need reinforcement due to PV generation. After the 8% point, reverse power flows begin to occur and voltage rise problems become more severe, thus requiring significant reinforcement of the network. Reinforcement cost then rapidly increases as PV penetration levels exceed 10%.

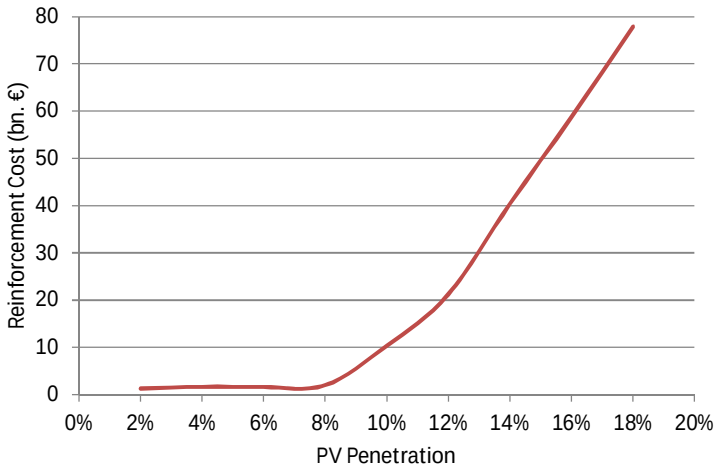


Figure 5.3 Total EU reinforcement costs (BaU) vs. PV penetration

The issue of voltage rise occurring as the result of high PV and wind penetration could be greatly mitigated using advanced technologies, such as smart voltage control or responsive demand. It is therefore critically important to understand the capabilities of these mitigation measures and include them in future distribution network planning tools. To further illustrate the related issues, Appendix 1 presents an example that illustrates the contribution of advanced network management technologies to improving the ability of the distribution network to integrate distributed wind generation.

5.2 Towards a cost-benefit based distribution network planning framework

Most network planning tools that are in use today are based on deterministic approaches, i.e. on current planning standards that define the required level of redundancy in the network, e.g. using the N-1 criterion. The expected future developments in distribution networks, such as the incorporation of electrified transport, demand-side response, distributed generation, storage, advanced network management techniques and more advanced ICT solutions, have the potential to increase the utilisation of network assets. However, there is a growing need to understand the implications of these developments and advanced solutions for network planning and security, as there is currently no established common approach to consider the risk profile of smart grid solutions. In other words, the present deterministic planning framework is unable to efficiently include new technologies in distribution network planning while ensuring that adequate levels of reliability are delivered to consumers.

This deficiency may require revisiting the fundamentals of network planning. In that context, this section describes the fundamental principles which will need to be incorporated into future planning tools in order to adequately treat new technologies, and in particular new demand associated with EV charging. Given that various smart grid solutions come with different costs attached, there is a need to understand how their performance and cost compare with those of traditional asset-based solutions, in a comprehensive cost-benefit assessment. It has to be noted that in some countries the planning standards are currently undergoing fundamental review, and probabilistic planning philosophy is being gradually adopted. Network planning tools used by distribution network operators to ensure compliance with planning standards will need to accommodate this change.

5.2.1 Traditional distribution network planning philosophy

Approaches to distribution network planning vary across different countries; however the key underlying principles are broadly similar. Distribution networks are normally designed according to a certain security standard, the purpose of which is to provide sufficient assets to ensure an economic level of reliability of supply to the consumer. The key indicators of supply reliability typically include the frequency of interruption, duration of interruption and value of the service not provided.

In traditional distribution network planning the primary network assets (transformers, switchgear, overhead lines and cables) are selected with the objective to accommodate a set of pre-specified operating conditions, ensuring that the technical parameters of supply (e.g. voltage and power flows) are maintained within statutory tolerances, without the requirement for proactive network monitoring and reconfiguration.

The requirements to comply with the security standard are a key network cost driver. The level of security in distribution networks is defined in terms of the time taken to restore power supplies following a predefined set of outages. Consistent with this concept, security levels on distribution systems are graded according to the total amount of peak power that can be lost. A simplified illustration of this network design philosophy is presented in Figure 5.4. For instance, small demand groups with less than 1 MW peak demand are provided with the lowest level of security, and have no redundancy (n-0 security). This means that any fault will cause an interruption and the supply will be restored only after the fault is repaired, which can take up to 24 hours.

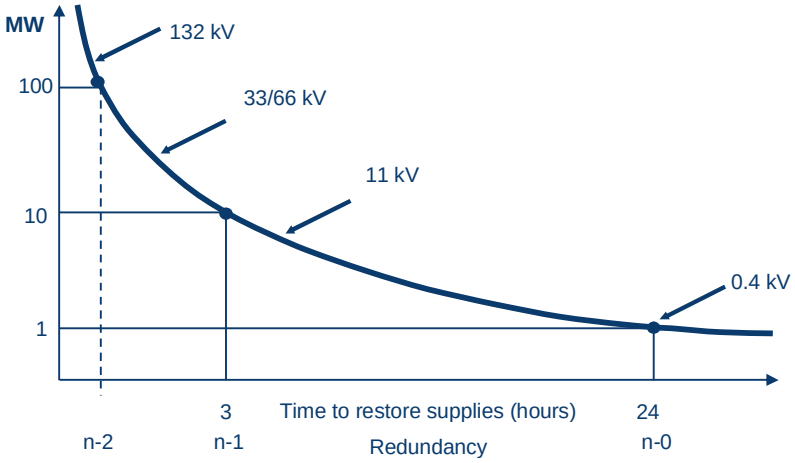


Figure 5.4 Restoration time-based network design philosophy as the function of peak network demand

Different redundancy levels have the following meanings:

- **n-0:** no redundancy in security (must wait for repair of network);
- **n-1:** one level of network redundancy; and
- **n-2:** two levels of network redundancy.

For demand groups between about 1 MW and 100 MW, although a single fault may lead to an interruption, the bulk of the lost load should be restored within around 3 hours. This requires the presence of redundancy, as 3 hours is usually insufficient to implement repairs, but it does allow for network reconfiguration activities. Such network designs are often

described as providing n-1 security. For demand groups larger than 100 MW, the network should be able to provide supply continuity to customers following a single circuit outage (with no loss of supply) but also provide significant redundancy to enable supply restoration following a fault on another circuit superimposed on the existing outage, i.e. n-2 security. The underlying principle in ensuring a given level of redundancy is to balance the cost of energy not delivered against the cost of additional investment into primary network assets.

5.2.2 Extending traditional approach to distribution planning to include both network and non-network solutions to facilitate network reinforcements

Most distribution planning and operation practices for the medium voltage network and above, are still centred on the historic deterministic "N-1" type criteria developed in the 1950s and that have been used to guide electricity distribution network reinforcement, design and planning. Although the networks, designed (and operated) in accordance with these deterministic planning standards have broadly delivered secure and reliable supplies to customers, the key issue going forward will be associated with the future evolution of the standard design concept.

Furthermore, distribution network planners could provide additional network capacity not only through building distribution circuits and reinforcing assets (asset-based redundancy), but also through non-network solutions involving demand, generation and more sophisticated network management, whichever is more efficient. The choice between different options requires an adequate cost-benefit analysis (CBA) methodology based on tools that are capable of representing the specific characteristics and constraints of different alternatives.[25]

The present distribution planning approach requires that network security is provided through asset redundancy (historical asset-heavy paradigm) which fundamentally contradicts the concept of Smart Grids that focuses on non-network solutions to network problems. In other words, the current planning paradigm can represent a barrier for innovation in network operation and design and prevent the implementation of technically effective and economically efficient solutions that enhance the utilisation of the existing network assets, reduce or postpone reinforcement and, as a consequence, maximise the overall social welfare.

An illustrative example of this issue is indicated in Figure 5.5, in which several solutions are considered: (a) traditional network reinforcement through network-based solutions, (b) distributed generation-based solution, (c) storage-based solution and (d) demand-side management-based approach (which can for instance include flexible EV demand).

[25] Examples of recent efforts undertaken in Europe towards defining a common CBA framework for Smart Grid projects include the JRC report "Guidelines for conducting a cost-benefit analysis of Smart Grid projects" (2012) and the European Commission's Smart Grid Task Force report "Definition of an Assessment Framework for Projects of Common Interest in the field of Smart Grids" (2012).

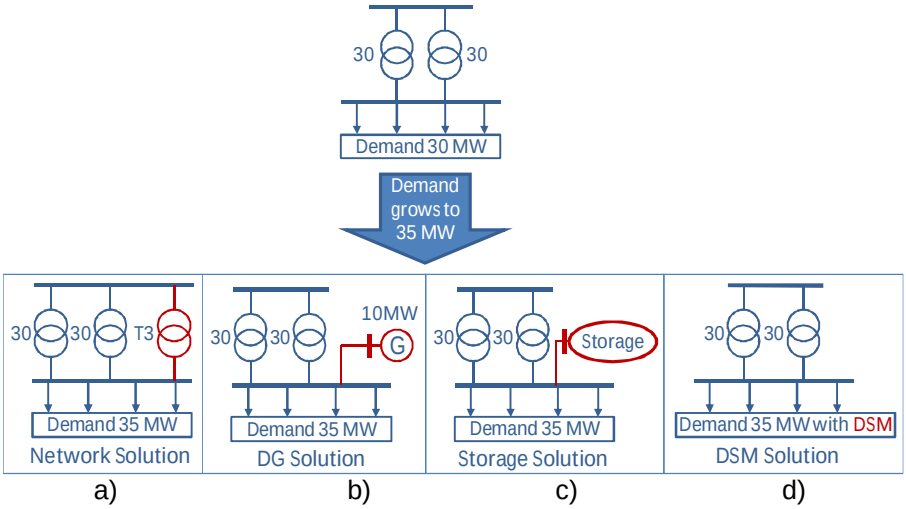


Figure 5.5 Range of network and non-network solutions for resolution of network security problems

In case of load increase, as indicated in the figure, traditional planning approaches would require network reinforcement (e.g. installation of third transformer) as indicated in the solution (a) in Figure 5.5. Regarding the other 3 non-network solutions, the key question is associated with the assessing the ability of these alternative solutions to substitute network reinforcement. In other words the network planners will need to determine the "capacity value" of the alternative non-network solutions, which requires assessment of the reliability performance. The risk profile of non-network alternatives, denoted by (b) to (d) in Figure 5.5, is not yet adequately understood, not only because of greater complexity and uncertainty but also because those options have only recently begun to be studied in depth. Present distribution network planning tools are not capable of selecting an optimal portfolio of network and non-network based technologies to minimise the cost of delivering appropriate service quality to end consumers of distribution network.

In this context, distribution network planning practices and tools will need to evolve to enable network planners to consider both network and non-network solutions, with an in-depth understanding of risks involved with each of the options. On the other hand, the regulatory framework governing the distribution business will need to adapt to incentivise DSOs to consider non-network solutions as an alternative to investing into new network assets.

One of the first departures from the historical network planning processes towards achieving network security through both network redundancy and incorporating non-network solutions has been carried out in the UK and the authors of this report have developed network modelling tools to inform this process. Although the focus of this work is on the concepts behind including distributed generation (DG) into distribution network planning, similar approaches are now being considered to be applied to flexible demand technologies, such as EVs.

This topic is particularly relevant in the context of the expected increase in the deployment of distributed renewable generation (primarily wind and solar, but also biomass, waste and other technologies), which is receiving strong incentives across Europe. An important technical issue here is the contribution that this new generation could potentially make to distribution network security. A detailed elaboration of the development of new planning

security standards is provided in Appendix 2, and is also accompanied by illustrative examples.

5.2.3 Probabilistic cost-benefit approach to network planning

Given the probabilistic nature of network failures and firmness of service of non-network solutions, a probabilistic cost-benefit based framework should be the benchmark in the future for assessing different options for the development of network design (and reinforcement) strategies. This will become even more relevant in future distribution networks characterised by high EV uptake, due to uncertainty related to the timing and location of EV charging demand.[26]

As indicated in Figure 5.6, the probabilistic approach can provide the basis for risks of supply interruptions to be understood, quantified and managed through optimising the amount of the network capacity required at both operational and investment time horizons. Essentially, this approach would enable the costs of network investment to be balanced against the benefits that the released network capacity can be expected to deliver to the network users.

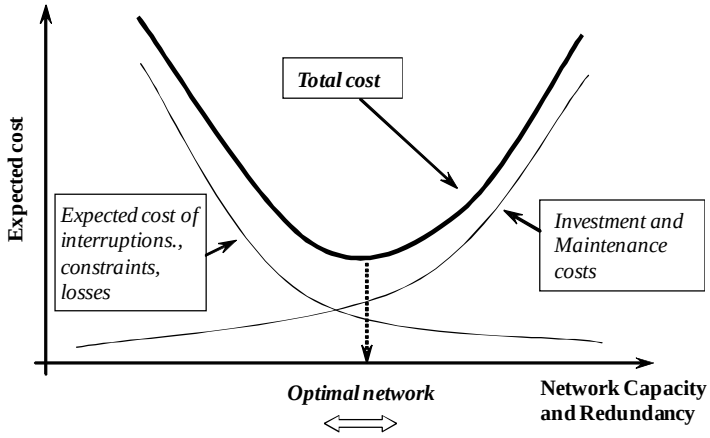


Figure 5.6 Probabilistic cost-benefit analysis framework for distribution network operation and planning (balancing of network operation cost, which includes cost of service interruptions and application of alternative non-network control technologies, against the cost of investment in network assets)

Furthermore, the probabilistic approach will provide a framework within which both network and non-network solutions, such as flexible demand and generation, can be objectively compared and thus solve network problems. Therefore, this framework would provide a benchmark for assessing economic efficiency of any future network design philosophy.

The EEGI Roadmap 2013-2022 recognises the need to develop new network modelling and shift towards stochastic optimisation tools, as well as intelligent network planning approaches.[27] These areas are seen as key scientific innovation requirements for European

[26] Uncertainties associated with distribution network planning in the context of rapid deployment of EV are discussed in more detail in Chapter 6.
[27] European Electricity Grid Initiative, "Research and Innovation Roadmap 2013-2022", January 2013. Available at: http://www.gridplus.eu/eegi.

DSOs in the next decade, along with the system integration of new power technologies and the impact of the active distribution network paradigm on network planning.

5.2.4 Balancing risks and redundancy of assets in distribution network planning

Cost-effective integration of low-carbon generation and demand technologies, with the latter being embodied by electromobility, will require fundamental changes in the historical philosophy of network operation and planning. However, before the need for new network investment can be established, it is critical to ensure that rules used to determine the volume of network capacity that can be released from current assets to network users in operational timescales, are efficient. For instance, for a given network asset, it is common to observe forced levels of underutilisation with the intention of preserving sufficient margins for security purposes. These security margins may, in turn, constrain access to capacity for network operation and make it less efficient.

The basis for establishing an optimal level of network capacity that should be made available to network users (by network operators) in real time and how much needs to be reserved for security reasons is a key question to determine efficient levels of network investment. According to the historical practice, this is achieved through various operational rules codified in the form of network standards that define minimum levels of network redundancy that must be maintained to cope with unexpected events, e.g. network outages.

These network planning and security standards have been based on deterministic operation and design criteria whereby electricity networks should be able to withstand a loss of one or two circuits (i.e. N-1 or N-2 deterministic network criteria[28]) without causing overloads of any other circuit and such outages must not threaten the integrity of system operation. Historically, this practice has delivered a successful operation of massive and complex electric networks in the absence of advance technology to monitor, predict, simulate and control them in real time.

Recently, however, there have been significant debates associated with updates of network operation and planning standards and practices in a number of jurisdictions. This is driven by a variety of factors including the need to:

- Incorporate non-conventional distributed generation which has exposed the inadequacies of the existing peak-driven planning and security standards given the limited capacity value of distributed generation.
- Demonstrate that investment in monopoly functions is efficient and delivers the best value for consumers, i.e. provides the right balance between costs involved (paid by the users) and benefits that users derive from it, including reliability improvements.
- Ensure that network planning and operational standards do not impose unnecessary barriers to entry and do not prevent a timely connection of new distributed generating plants and demand.
- Consider the application of advanced information and communication technologies (ICT) as a part of electricity grid infrastructure, combined with recent developments of advance distribution network technologies, such as distribution network active management schemes for control of generation and responsive demand supported

[28] In some distribution networks, such as in France, there is no absolute criterion such as N-1. Network planning is rather based on finding an optimal trade-off between the cost of outages and the investment cost.

by application of Dynamic Line Rating, smart voltage regulation, advanced power electronic devices for network topology control etc. These techniques can provide an efficient solution for the provision of network security and lower the level of network redundancy.

Given this new reality, it becomes necessary to determine the optimum level of asset capacity released to network users such that risks and benefits are adequately balanced. This can be only considered within an appropriate probabilistic framework since deterministic rules are barely a binary measurement of risk. Furthermore, the degree of security provided by deterministic planning criteria is unlikely to be optimal in any particular instance, as the cost of providing the prescribed (deterministic) level of security is not balanced against the reliability benefit delivered.[29] In contrast, a network planning approach that is established within a probabilistic cost-benefit framework is, in principle, superior over the historical deterministic approach, as it balances more accurately the reliability (and other) benefits against operation and investment costs incurred to deliver these benefits. Given the advances in reliability analysis techniques over the last 20 years, probabilistic network planning within a cost-benefit framework is now feasible.

The application of the probabilistic cost-benefit approach and post-contingency control through new technologies suggests that the network capacity that can be optimally released to users changes significantly depending on actual system conditions. Furthermore, studies show that any attempt to fix a single generic value for maximum network utilisation / minimum network redundancy, as in the present standards, will lead to inefficiencies, limiting the amount of capacity that can be released to network users.

5.3 Planning of distribution networks under uncertainty

Most flexible demand (such as flexible EVs) and DG technologies have inherently uncertain characteristics, which introduces significant challenges when integrating these new technologies in distribution planning tools. High level of uncertainty and variability leads to the conclusion that present deterministic planning tools may need to be replaced by probabilistic and stochastic approaches to distribution network planning. This section discusses the key sources of uncertainty and their integration into the distribution planning framework.

The largest proportion of DG and flexible demand technologies (e.g. EV) are characterised by an inherent unpredictability and operational uncertainty, which introduces significant challenges if these new technologies are to be integrated in distribution planning. The operation of these components may be influenced by weather conditions, users' preferences and requirements, as well as their interactions with energy markets, external to the distribution network framework.

Furthermore, the lack of operating experience associated with these technologies and components creates significant difficulties in predicting their behaviour and ensuring their timely contribution to constraint mitigation measures, especially when considering security and reliability contributions.

[29] The reliability benefit of an investment reflects the reduction in risk of service interruptions that accounts for the probability of an undesirable outcome *and* for the consequences of such an outcome.

Three key aspects of uncertainty associated with future generation and demand technologies relevant for distribution planning include:

1. Volume and type of technologies deployed in the network
2. Timing of deployment
3. Location in the network where these technologies are connected

In the conventional planning paradigm, distribution networks have been designed with an in-built capacity to deal with worst-case operational conditions. This regime leads to low asset utilisation and consequently high capital costs. In light of this, presence of high uncertainties and variability leads to the conclusion that deterministic planning tools should be replaced by probabilistic and stochastic approaches to distribution network planning.

5.3.1 Option value of network investments

The increasing uncertainty that surrounds future needs for distribution network capacity, coupled with the irreversible nature of capital investments, indicates that attractive investment opportunities should not be identified solely on the basis of net benefit, but also on the option value that they provide. The concept of option value is a well-established notion referring to the value placed on the ability to utilise an asset in the future and is recognised as an important element of the total economic value of a project.

Full consideration of the above concepts in the distribution planning process necessitates a shift from traditional deterministic or sensitivity analysis methods towards flexible planning and valuation frameworks. It is important to highlight that examining single scenarios in isolation gives no information on how an investment could adapt to the unfolding uncertainty.

Fully embedding uncertainty within the distribution network planning decision process itself is essential for the proper evaluation of flexible solutions. Scenario trees may be well-suited for capturing uncertainties associate with the evolution of EVs or distributed generation in future years or the penetration of demand-side participation measures. Since these events cannot be described by historical data or parametric probability distribution functions, a scenario tree could be developed to describe the possible states of the system, as shown in Figure 5.7(ii). It is usually the product of expert opinion, industry surveys and analysis of the underlying market dynamics (e.g. public acceptance of demand-side services, government subsidies for particular types of distributed generation etc.).

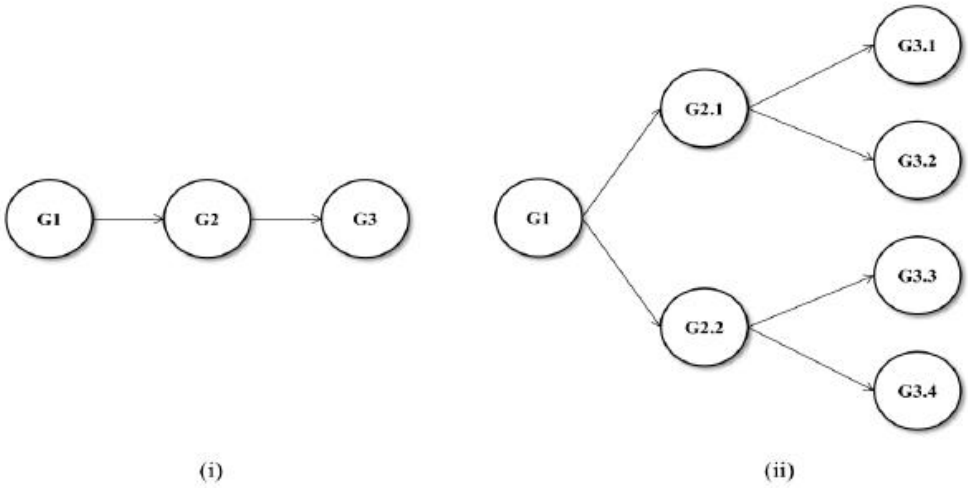


Figure 5.7 (i) Illustration of a deterministic description of the future system. (ii) Illustration of a stochastic description of the future system. Each circular node represents a possible future system state, with G1 being the present state.

It follows that with the introduction of scenario trees, the planner's objective becomes the identification of investments that can minimise expected system costs over the planning horizon. However, a parameter that needs to be appropriately considered in this new cost-benefit framework is the planner's ability to dynamically adjust his plans to the unfolding scenario realisation.

When faced with an uncertain future, network planning decisions have to be taken with subsequent adaptability in mind and the concept of following a one-dimensional plan is rendered obsolete. In its place, the concept of a flexible expansion strategy emerges, where the transition to a new state can be treated as a trigger event that differentiates the proposed investment plan. Under this paradigm, decisions to be taken now do not simply constitute the first stage commitment of a sequential plan, but sit within a larger strategy that considers the cost of future adjustments to a range of scenario realisations.

The concept of embedding decision flexibility in a decision making process is shown graphically in Figure 5.8 with the aid of decision trees consisting of circular chance nodes (system state) and rectangular decision nodes. It is important to highlight that although the network planner would be interested only in the optimal first-stage decision (decision node D1 in the Figure 5.8(ii)) which can be readily implemented, the ability for flexible recourse in the future can substantially influence the result.

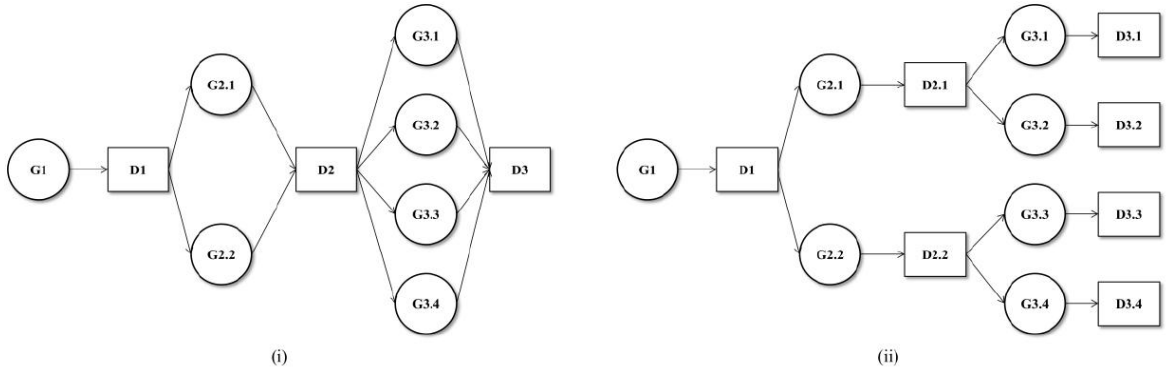


Figure 5.8 Probabilistic decision frameworks (i) ignoring flexibility and (ii) considering flexibility.

All the concepts described above can be formulated into a stochastic optimisation problem enabling the evaluation of complex systems while considering a large number of different scenarios.

In conclusion, moving from a static to a flexible network planning framework enables the planner to make best use of the available information while also identifying the optimal exercise strategy of all available options. Given the large scale of upcoming changes in the distribution networks as well as the extended scope for synergy and strategic coordination, the introduction of such tools within the planning process becomes increasingly important.

5.3.2 Forecast improvement

DSOs are not experienced with the operational patterns of new demand and DG technologies since their deployment is a relatively recent development. Also, some of these patterns are highly variable and intermittent. Long-term forecasting of load growth under the envisaged electrification of heat and transport sectors lacks historical data to train forecasting models. Finally, the large-scale deployment of EVs will add a locational as well as the temporal dimension to the deficiencies of existing forecast tools. Therefore, the forecasting task becomes significantly more challenging. Gathering data from the envisaged massive smart meter roll-out in order to inform the DSOs about new DG and demand connections and behaviours is crucial for improving forecasting strategies.

In today's LV networks very little if any forecasting is being done and a widespread use of forecasting tools by DSOs will become a necessity even for lower voltage levels. These forecasts could be used directly to support "preventive security" or indirectly to improve current forecasting practices based on load profiling.

5.3.3 Snapshots vs. multi-temporal simulations

Traditional distribution planning tools have been based on decision making driven by a fixed set of worst-case operating snapshots, involving different combinations of minimum and maximum levels of demand and DG output. The following scenarios are largely accepted as the most critical snapshots:

1. Minimum DG production and maximum local demand

2. Maximum DG production and minimum local demand

In addition, demand not only grows and changes over the years but also varies continuously. This variation increases as more flexible demand and storage are connected to the networks. To consider these variations and take advantage of demand flexibility, simulations should be carried out on a multi-temporal basis. In order to address the resulting computational burden, these simulations should be executed for different characteristics days.

5.3.4 Impact of new ICT infrastructure on the performance of future distribution networks

Increasing the deployment of smart and active management approaches at the distribution network level requires the installation of a significant volume of assets related to information and communication technologies (ICT). These assets are needed to enable the communication between different elements in the network and control over flexible DG, demand and network components.

Wide-scale introduction of ICT solutions in distribution networks creates an additional layer of complexity with respect to how the networks operate in real time. The additional complexity introduced by ICT will have an impact on the reliability performance of distribution networks, which cannot be ignored in the likely future scenario where all the advanced functionalities of the network depend on a reliable communication and control infrastructure. Therefore, any approach to network reliability assessment built into current planning tools will need to accommodate the reliability performance of the ICT infrastructure as well. Current tools typically do not consider ICT explicitly in distribution reliability assessment.

There is a growing recognition in the research community that a unified “electrical + ICT” representation of the system may become more appropriate for planning future distribution networks. Certain network functions are understood to be particularly closely linked with the performance of the underlying ICT infrastructure, such as:

- Network voltage control
- Metering
- Control of PV and wind in distribution networks
- Substation reliability

5.3.5 EV demand uncertainty

Assessing the future electricity demand of EVs when planning distribution networks is a representative case of forecasting a segment of demand which exhibits uncertainty in several critical ways:

- Future evolution of the number of EVs is highly uncertain, as this is a new technology and forecasting its uptake is rather difficult. In addition to the uncertain number of EVs in e.g. the national vehicle fleet, it is further difficult to predict the distribution of EVs across different regions and distribution networks (e.g. urban, rural etc.). In other words, despite the number of EVs nationally being rather small, there might be pockets i.e. areas of high EV uptake where the additional stress placed on the local distribution network will require reinforcements.

- EV demand pattern is expected to vary over time, reflecting the EV users' behavioural patterns (commuting to work, shopping trips, leisure activities etc.), which are not perfectly predictable.

- Unlike other traditional demand segments that were predominantly stationary, EV demand may shift its location as well as time. For instance, an EV user may decide to charge the battery at work or at a public charging point, although the user normally does most of the charging at home. This is even more pronounced for users with no access to home charging, who will rely on the network of public charging stations to meet their electricity requirements. Establishing the typical usage patterns of a diverse mix of EV users is likely to require an intensive learning process, as there is currently very little data available to calibrate the EV demand models.

5.4 Implications for future distribution network planning and functionality of future planning tools

All of the above considerations require a fundamental review of the current distribution network planning and security standards when facing the expected changes in the electricity supply industry, among which the electrification of transport will play a prominent role. Future distribution network planning standards and tools should assist network planners in selecting optimal portfolio of network development strategies, including network reinforcement, application of distributed generation, flexible demand (e.g. EVs), application of energy storage technologies and advanced network technologies (e.g. smart voltage regulators) so that overall investment costs of these options is balanced against the value they bring to delivering quality of supply to network consumers.

It is also critical for the new tools to include the implications of these advanced solutions for network security, i.e. take into consideration the risk profile of smart grid solutions, to ensure that adequate levels of reliability are delivered to consumers. It will therefore be necessary that new tools are capable of performing comprehensive cost-benefit assessments.

A link will need to be established between the active distribution network operation solutions and schemes and the distribution network planning activity. It is evident that active network management may require significantly less reinforcement to accommodate new demand as the result of heat and transport electrification. Future distribution planning tools need to be able to adequately take into consideration this link between smart network operation and lower requirements for asset redundancy, while giving full consideration to the risk profiles of smart solutions, in particular the ICT infrastructure.

The largest proportion of flexible demand (e.g. controllable EV loads) and DG technologies are characterised by an inherent uncertainty, which introduces significant challenges when integrating these new technologies in distribution planning. In light of this, presence of high uncertainties and variability leads to the conclusion that the present deterministic planning tools should be replaced by probabilistic and stochastic approaches to distribution network planning. These tools will also need to consider the implications of increased use of ICT and corresponding risk exposures.

6 Summary of key observations

One of the key concerns for distribution networks in the future is that the widespread integration of electrified transport may lead to increases in peaks that are disproportionately higher than corresponding increases in annual electricity demand. This will potentially require significant reinforcement of distribution network infrastructure, reducing at the same time the utilisation of network capacity. As a consequence, the system integration cost of electromobility is likely to increase substantially.

In order to achieve a more efficient operation and design of distribution network, it may become necessary that new smart technologies replace some of the traditional network solutions. Most current planning tools are not capable of adequately considering non-network solutions and their contribution to network security, due to the lack of understanding of the risk profiles of new technologies, which also includes the performance of new ICT infrastructure. This report has therefore outlined the areas where a thorough review of the current planning tools is necessary to ensure that new tools have the functionalities necessary to include new non-network technologies, in particular flexible EV demand, into network planning. A number of illustrative examples have been presented in the report indicating the importance and the magnitude of different effects that advanced technologies and solutions may have on distribution network in the future.

Based on the considerations laid out in the report, the following aspects of enhancing the existing distribution planning tools need to be prioritised:

- Probabilistic cost-benefit analysis should provide a benchmark in future network planning tools for investment decisions into new distribution assets, balancing the cost against benefits in terms of reduced risk for network users.

- A shift from system-level indices to consumer-level indices may be needed in future network planning tools when assessing the reliability performance of the system, to ensure that investments into reliability improvements are adequately balanced against the value that different customers place on avoided interruptions in supply.

- A number of mitigation measures, such as advanced network control techniques, should be considered in future network planning tools, in particular when faced with high penetration of distributed renewable generation.

- Value of non-network solutions such as demand response and storage should be thoroughly understood and taken into consideration in distribution network operation as well as in future network planning tools. This in particular includes the risk profiles of the non-network solutions, also including the accompanying ICT infrastructure.

- Uncertainty of new demand and generation technologies should be given special attention in future network planning tools. Stochastic and probabilistic simulations should replace snapshot studies, and multi-temporal simulation capability should be included in the tools. Short- and long-term forecast of generation and demand, particularly EVs, should be improved.

- Relationship between distribution system reliability on one hand, and the use of ICT systems and their vulnerability on the other needs to be adequately characterised in future network planning tools.

Given that this report has provided a comprehensive overview of the advantageous enhancements of future network planning tools with a broader view than just looking into the impact of electromobility, the following areas for improvement are identified as particularly relevant for an efficient integration of EVs into future network planning tools:

- Improving the short- and long-term forecasting of EV demand in future network planning tools, both in terms of time and location.

- Stochastic and probabilistic multi-temporal assessments should replace snapshot studies to address the uncertainties related to EVs in future network planning tools.

- The value of different EV charging control approaches (e.g. direct control-based or price-based), being one potential category of non-network solutions, should be thoroughly understood and taken into consideration in distribution network operation and in future network planning tools, along with the other non-asset solutions available to network operators. The planning framework should further take into account that the EV charging control could be performed not only to support the DSO requirements, but also to the advantage of other entities in the system that could have different needs and purposes.

- Including EVs into the probabilistic cost-benefit analysis framework in future network planning tools, which balances costs against benefits in terms of reduced risk for network users, also taking into consideration the option value of various opportunities associated with smart EV charging. The cost-benefit assessment should take into consideration any additional cost of the necessary ICT infrastructure, while at the same time quantifying the implications of controlled EV charging on the risk profile of the network.

Appendix 1: Examples of applications of demand-side response, energy storage and advanced network management technologies

This Appendix presents further examples of using the flexibility of responsive demand, storage and active network management to ensure a more efficient investment into distribution assets. By integrating smart meters with appropriate functionality and communication systems into real-time distribution network control, it is expected that the need for network reinforcement may be significantly reduced, through locally optimising the actions of various types of responsive demand and storage and the use of smart network technologies. Flexible demand types considered in this overview include residential heat pumps, smart domestic appliances and water heaters (this list is by no means exhaustive, i.e. there may be other technologies with the potential to contribute to more efficient operation and design of distribution networks).

Future costs of network reinforcement will be driven by the network control and design concepts and in this context it is possible to contrast two approaches:

- First, following the present 'unconstrained' network operation philosophy with the distribution network control problem being resolved in the planning stage, i.e. Business as Usual (BaU) approach where the distribution network is designed to accommodate any reasonably expected demand; and

- Second, involving real-time network management through optimising demand response, i.e. a paradigm shift in network control philosophy that uses the advanced functionality of smart meters and appropriate communication infrastructure to optimise responsive demand at the local level in order to manage network constraints and avoid or postpone network reinforcements.

Under the 'Smart' operation paradigm, which optimises demand response in real time to minimise the impact on the network, any constraints associated with demand flexibility need to be fully respected, so that the intended service quality is not compromised in any respect.

Heat pumps

Heat sector is another area with a significant potential for decarbonising, both through replacing older gas-fired, oil-fired or LPG-based domestic heating with electricity-based heating provided by electric heat pumps (HP) and using heat pumps as a low-carbon space heating option for new housing. Two basic HP types are air-source and closed-loop ground-source type. The key parameter of HP performance is its Coefficient of Performance (COP). When the heat pump is used for heating, COP is defined as the ratio of the heat supplied to the energy carrier medium, to the electric input into the compressor. Although ground source HPs generally provide better energy performance i.e. higher COP, their installation costs are normally higher.

Given the characteristics and constraints of HPs (i.e. low-temperature operation and hence reduced rate of heat delivery), a HP system could be accompanied with a thermal storage of certain size in order to follow heat requirements more closely with lower HP ratings. That would potentially lead to more continuous operation of heat pumps, but will also provide an

opportunity to optimise heat pump operation not only to meet local heat requirements, but also to contribute to grid management.

The network that is used to illustrate the contribution of flexible HP systems to distribution network operation is a residential network, with 5,000 customers. It is assumed that all 5,000 customers use HPs for heating, following the heating requirements characteristic for a cold winter day. With no storage available, i.e. with no ability to modify the operating patterns of HPs, the total demand profile for the analysed network is depicted in Figure A1.1 (left), where HP demand has been added on top of the baseline (no-HP) network demand. If there is heat storage available in each HP system, in the amount of 20% of daily heat requirement, the peak in the resulting total demand profile can be significantly reduced, as indicated in the right-hand side of Figure A1.1.

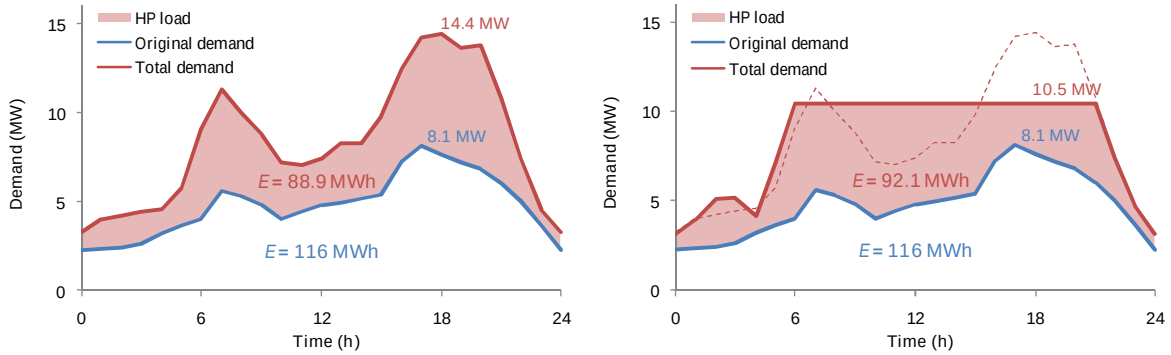


Figure A1.1 BaU (left) and Smart (right) HP operating profile in a residential area (5,000 customers)

If large volumes of heating demand are shifted in time by using heat storage, this will cause energy losses due to the cycle efficiency of the storage. The increased energy consumption will increase the cost of electricity for the customers, although this increase is expected to be minor compared to the potential savings in distribution network cost. Nevertheless, it needs to be kept in mind when including flexible HP systems into distribution network planning.

The benefits of Smart HP operation based on the example presented in Figure A1.1 are depicted in Figure A1.2. This illustrative example indicates that the benefits in terms of avoided overloading of LV cables and transformers are more significant for modest penetration levels, and saturate for high levels of uptake. This is expected as the energy requirements of the heat sector are more significant than e.g. for EVs, and accommodating considerable increases in energy delivered will lead to overloads.

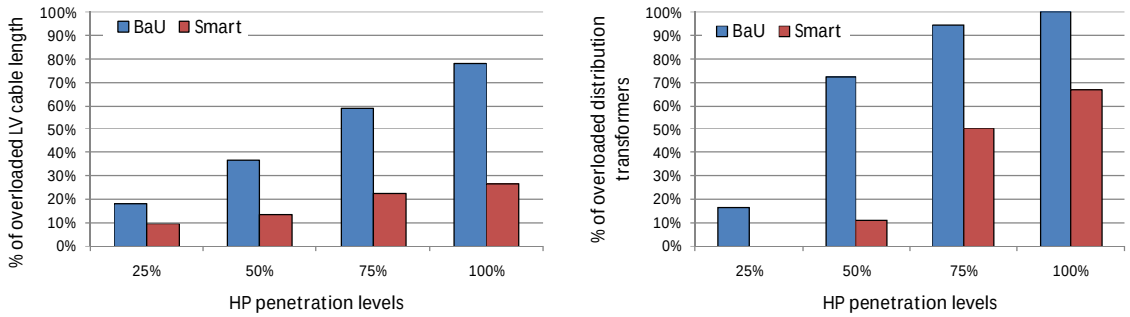
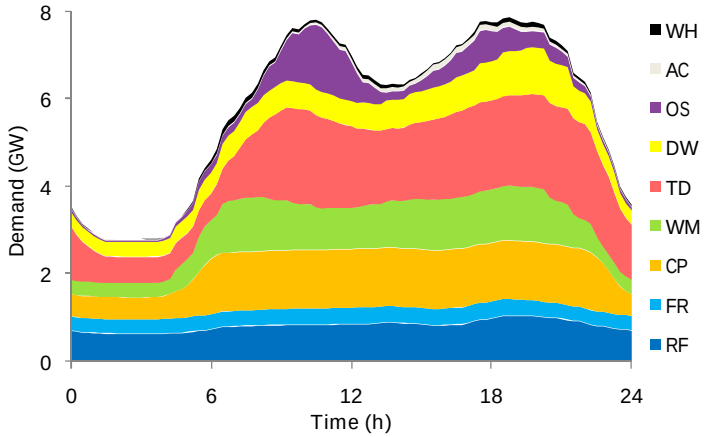


Figure A1.2 Percentage of overloaded LV feeder length and distribution transformers for different penetrations of HPs

Smart domestic appliances

Household appliances form a significant part of energy consumption, typically representing around 10% of the total annual energy consumption. The principle of Smart operation here is to modify appliance usage patterns according to the conditions in the system, using smart appliances as sources of demand-side flexibility. Smart appliances would then be able to provide a range of services to the electricity system, such as generation/demand balancing, frequency control, standing reserve, peak reduction and network congestion management.

The examples presented in this section focus on three types of wet appliances: washing machines (WM), dishwashers (DW), and washing machines equipped with tumble dryers (WM+TD). The data relevant for the use of appliances and the optimisation of their operation has been taken from the Intelligent Energy Europe Smart-A project. For instance, an estimate of the diversified daily demand of different appliances in one country is illustrated in Figure A1.3. It is apparent that some appliances, e.g. refrigerators (RF) and freezers (FR) have a nearly constant demand, while others, such as dishwashers (DW), have a higher demand in the evening. As a result, there is considerable potential to use these types of loads to provide demand-side flexibility.

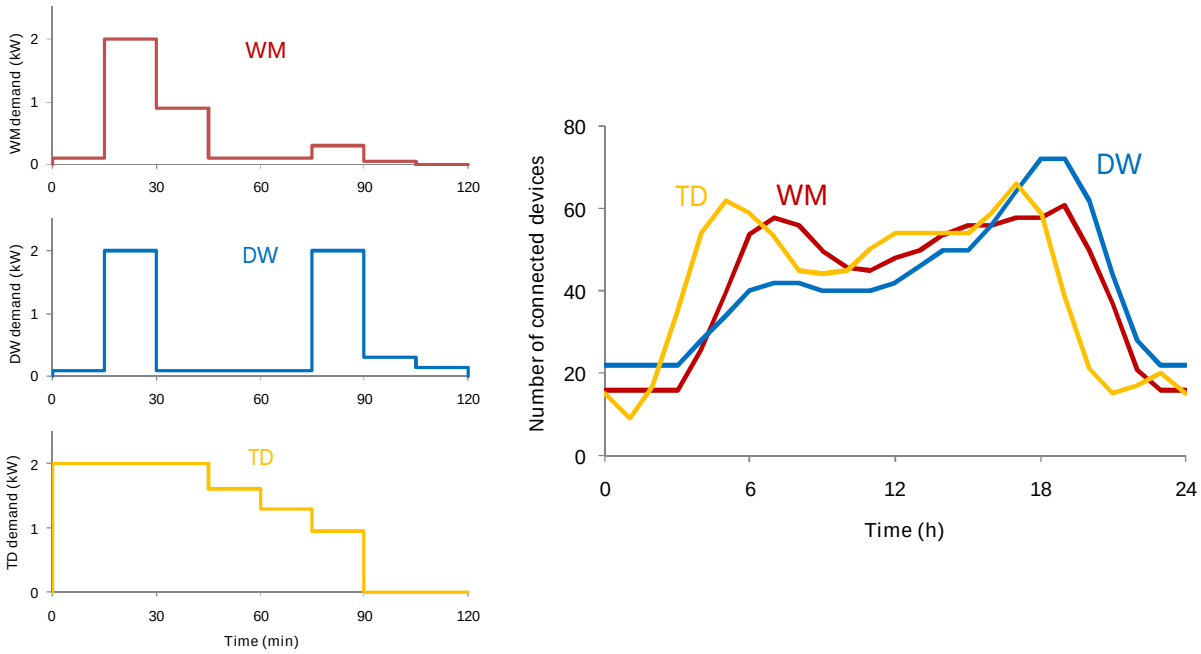


RF: Refrigerator FR: Freezer CP: Circulation Pump
WM: Washing Machine TD: Tumble Dryer DW: Dishwasher
OS: Oven and Stove AC: Air Conditioning WH: Water Heater

Source: R. Stamminger, “Synergy Potential of Smart Appliances”, Deliverable 2.3 of Smart-A project (No. EIE/06/185//SI2.447477), Nov 2008.

Figure A1.3 Average daily demand of domestic appliances

In order to quantify the potential benefits of shifting appliance demand cycles in time, it is necessary to establish the number of appliances starting operation at each instance in time. This is established from the diversified demand profile associated with each appliance type together with the corresponding operating cycle. An example of this data is shown in Figure A1.4 for WM, DW and TD data. The diversified profile represents the aggregated and normalised demand of an average appliance, suggesting e.g. that most households use their washing machines early in the morning or in the evening.



Source: R. Stamminger, "Synergy Potential of Smart Appliances", Deliverable 2.3 of Smart-A project (No. EIE/06/185//SI2.447477), Nov 2008.

Figure A1.4 Diversified demand of WMs, DWs and TDs (left) and consumption per operation cycle (right)

The incorporation of controllable wet appliances into distribution network planning is demonstrated on the example of a residential distribution network with 2,500 customers. Diversified load profile per customer for the peak demand day has been estimated based on the data typical for GB residential customers, with the diversified peak of around 1 kW per customer. The peak demand for the entire network under consideration is therefore around 2.5 MW, and occurs around 5pm, as indicated in Figure A1.5. Without any flexibility provided by domestic appliances, this peak demand of 2.5 MW would be used to determine the requirement for installing or reinforcing distribution network assets.

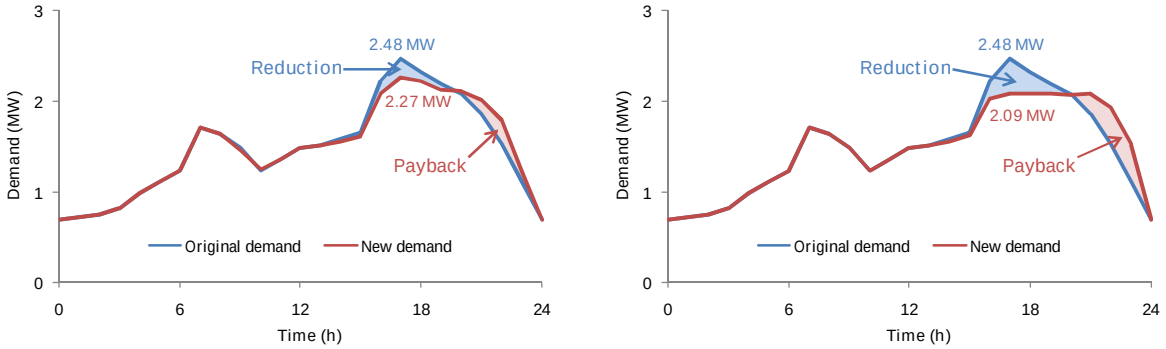


Figure A1.5 Reduced peak load in a distribution network for today's penetration (a) and with full penetration of smart appliances (b)

An analysis was carried out to demonstrate the capability of controllable smart appliances to reduce peak load in a distribution network for two different levels of penetration of smart appliances:

- Present level of penetration of wet appliances (Figure A1.5a), where 80% of household customers have a smart WM (or a WM+TD) and 20% of households have a smart DW;
- Full penetration of smart wet appliances (Figure A1.5b), where 100% of household customers have a smart WM (or a WM+TD) and a smart DW.[30]

The two cases are presented in Figure A1.5, where the left chart corresponds to current appliance penetration, and the right one assumes full penetration. Both the original and modified peak demand are indicated in the charts, suggesting peak reductions of 8.4% and 15.8% for current and full penetration, respectively. Obviously, due to higher flexibility, full penetration of smart wet appliances is capable of delivering a larger peak reduction than the current appliance penetration.

Reduced peak in this residential distribution network can be translated directly into savings in the cost of investing into new network assets. It follows that the flexibility potentially provided by smart domestic appliances needs to be adequately taken into consideration in cost-efficient distribution network planning.

Water heaters

Electric water heaters (WHs) are widely used to supply hot water to domestic and commercial premises. Due to the assumed inherent heat storage in the form of hot water tank, it is possible to perform load control over WH demand by disconnecting them for a short period of time, without any detrimental effect on the customers' hot water requirements.

An example is presented to illustrate the challenges and opportunities to use controllable water heaters in distribution networks to reduce the necessary network reinforcement through smart WH demand control.

Figure A1.6 presents an illustrative diagram of a typical diversified WH demand per device.[31] If all WHs were controlled in the same manner, for instance by disconnecting them from the grid between 4pm and 6pm in order to reduce the network peak demand, this would result in a zero level of demand during the control period. However, once the control has finished, there is a high spike of demand made by re-connected WHs, also known as the payback phenomenon, and is the result of WHs reconnecting back to recoup the energy needed to heat the water. The spike in diversified demand profile is the result of the fact that most water heaters will be connected after the end of the control period, i.e. results from the loss of diversity caused by control actions.

[30] The possible impact of higher penetration of smart appliances on the shape and magnitude of original demand profile has been ignored in this analysis, i.e. it has been assumed that the aggregate demand profile is the same regardless of the appliance penetration rates.
[31] Source: S. H. Lee, C. L. Wilkins, "A practical approach to appliance load control analysis: a water heater case study", IEEE Trans. on Power Apparatus and Systems, Vol. PAS-102, No.4, April 1983, pp. 1007-1013.

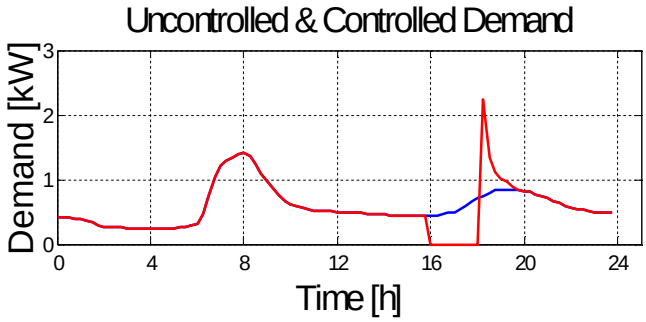


Figure A1.6 Diversified WH demand profiles with and without control

The above effect suggests that instead of applying simple but ineffective control based on disconnecting all WHs at the same time, a more appropriate WH control should involve staggering control period across WH groups. An example of this approach is illustrated on a residential distribution network with 2,000 customers that use WHs, and is based on the authors' previous analysis. As indicated in Figure A1.7, in an optimal control approach, the control actions of individual WHs are distributed across time in order to achieve an effective reduction in the peak demand of the observed network.

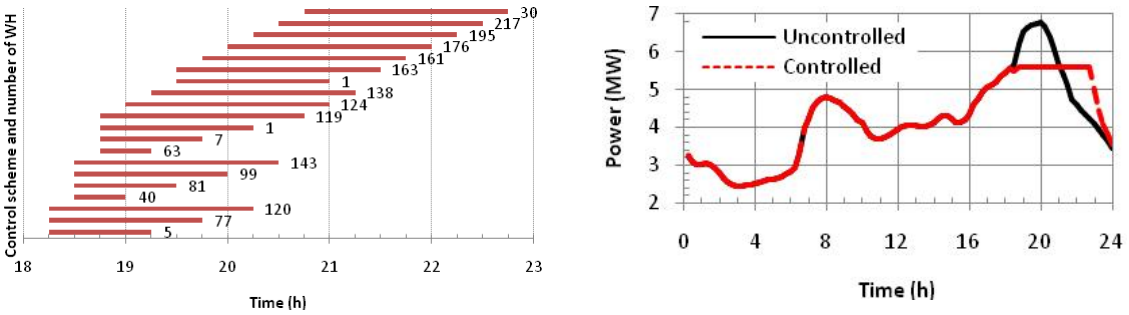


Figure A1.7 Advanced WH control strategy to minimise peak load

The example above also illustrates that understanding the diversity of a given controllable load category, as well as the service provided to the end user is critical for being able to effectively integrate the demand flexibility into distribution network planning.

Energy storage

Energy storage is another example of a mitigating technology capable of avoiding or deferring distribution network reinforcement. This capability is demonstrated on a 38-bus network depicted in Figure A1.8, which is assumed to experience a 30% load growth in 20 years (i.e. around 1.3% per year). As indicated in the left-hand part of the figure, a significant number of lines in the network require reinforcement during the 20-year period due to thermal overloading. For instance, the line between buses 1 and 2 needs to be reinforced already in Year 4.

If on the other hand a storage device is installed at the most distant bus (No. 38 in this example), the number of lines requiring reinforcement within the 20-year planning period is substantially lower, and those that do require reinforcement need to be addressed significantly later than without having storage in the grid (see the right-hand side of

Figure A1.8). For instance, line 1-2 now only needs to be reinforced in Year 9, rather than in Year 4, which was the case when no storage was present on the system.

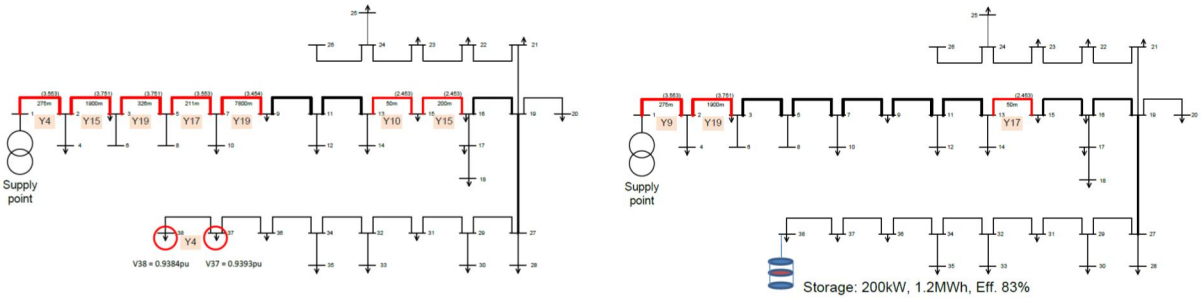


Figure A1.8 Congested lines and reinforcement schedule caused by load growth: (i) without storage, (ii) with storage installed in the most distant bus

Figure A1.9 illustrates the power flow through line 1-2 with and without storage, when demand in the network increases by 11% compared to the base year. By injecting power into the grid, i.e. by discharging energy from the storage device during peak hours, it is possible to reduce the loading of line 1-2 below its rating of 3.5 MVA and defer its reinforcement by 5 years. It is only when demand increases by 12% compared to the base year (which occurs in year 9 of the study period) that storage can no longer postpone the reinforcement of the line, as indicated by the black dashed line in Figure A1.9.

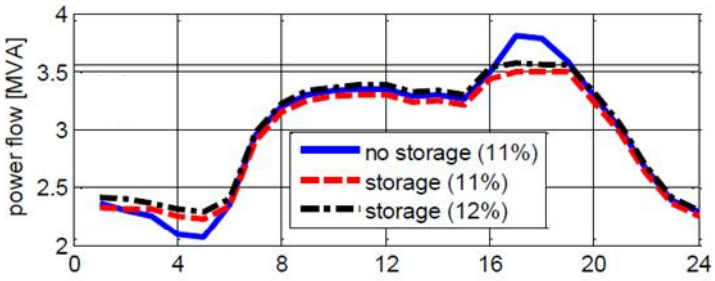


Figure A1.9 Apparent power flow through the most congested line (Bus 1 – Bus 2)

Advanced network management technologies

The following example illustrates the contribution of advanced network management technologies to improving the ability of the distribution network to absorb the output of distributed wind generators. The 33 kV distribution network shown in Figure A1.10 is fed from a 132 kV network (bus 1) through an OLTC-transformer. Loads are connected to busses 2, 3, 4 and 5 (the load at bus 2 represents the aggregated loads of the remaining part of the system). Distributed wind generation is connected at bus 6, where power factor correction capacitor is also connected.

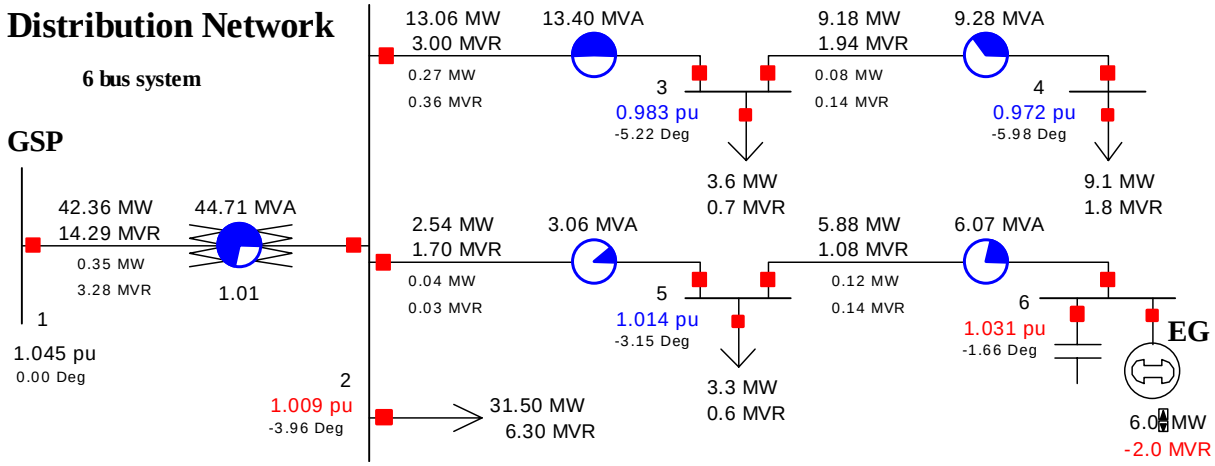


Figure A1.10 Distribution test system, with values shown for maximum loading condition

The following mitigation measures are considered in this example:

- Generation curtailment
- Power factor compensation
- Area-based OLTC voltage control
- In-line voltage regulators

Various combinations of measures are considered in the four advanced network management (ANM) schemes. The top left charts in Figure A1.11 shows the annual energy produced and curtailed with installed capacity of wind generator ranging from 4 MW to 20 MW. Based on the current practice, the capacity of DG allowed for connection is generally limited by the extreme situation of minimum or maximum loading and maximum generation output. This condition allows only 6 MW of generation to be connected to this network. In case of area based voltage control, (Figure A1.11, top right) penetration levels of up to 14 MW can be achieved with virtually no energy curtailed. Area-based voltage control by OLTC transformers clearly allows a considerable increase in the allowable penetration of distributed generation. It is, however, important to remember that this technique of voltage regulation will require the implementation of a distribution management system with appropriate communication systems. Finally, *application of* independent voltage regulation clearly increases the amount of generation that can be connected (up to 20 MW) with almost no curtailed energy.

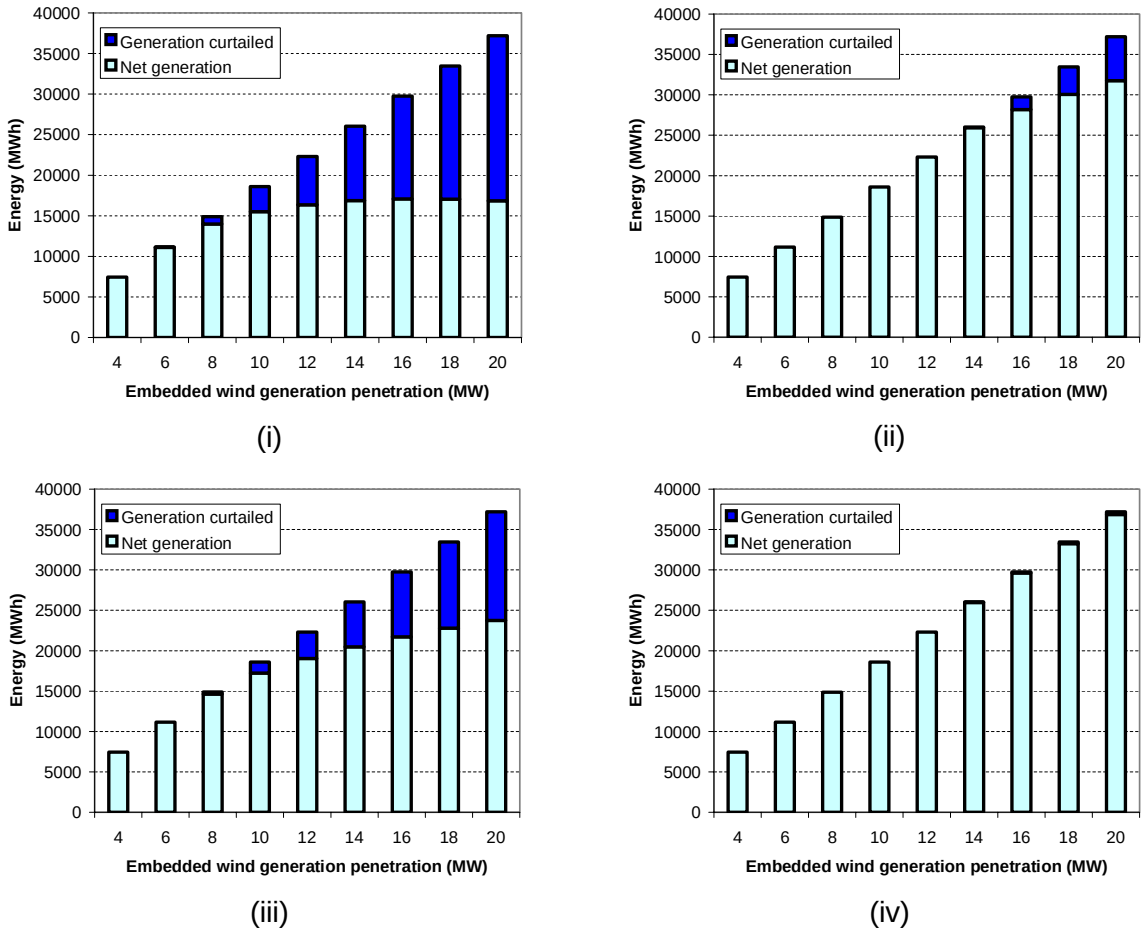


Figure A1.11 Benefits of alternative ANM schemes: (i) 0.98 power factor, (ii) 0.95 power factor, (iii) Area-based OLTC voltage control, (iv) Area-based OLTC voltage control and in line voltage regulators

Connecting distributed generators alters the loss performance of distribution networks. Small penetrations of distributed generation tend to reduce network power flows, and thus network losses. However, at large penetrations the distributed generation will export power to the grid, which may lead to an increase in losses. Figure A1.12 illustrates the change in network losses for various levels of penetration and for four different voltage control strategies applied in the above system. For low penetrations the losses are reduced regardless of the approach to voltage control. For higher penetrations, made possible by the application of OLTCs and voltage regulators, losses are significant due to the increased amount of renewable energy generated. It is necessary to adequately quantify this impact when evaluating the mitigation technologies in future network planning tools.

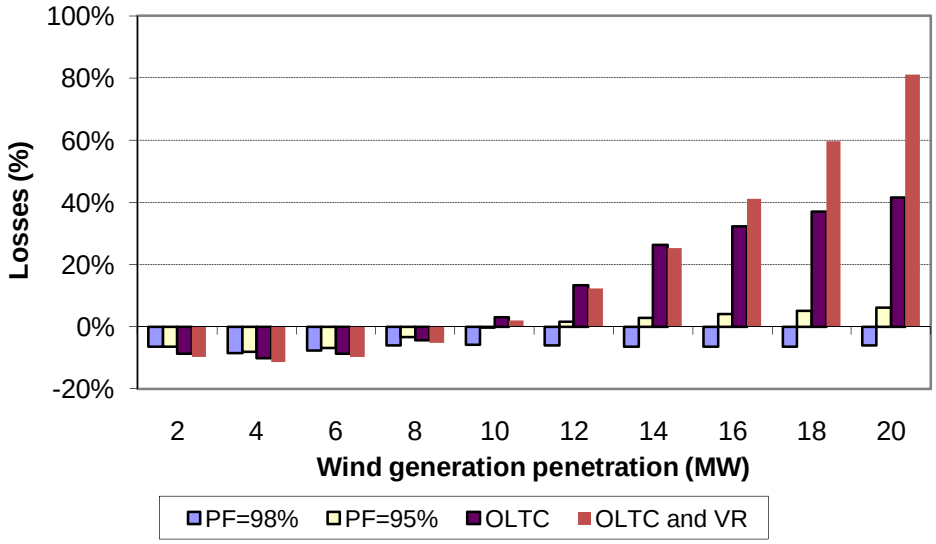


Figure A1.12 Impact of active network management schemes on losses for various levels of penetration of wind generation

Appendix 2: Including non-network solutions in distribution network planning and security standards

As discussed, one of the key features of future distribution network planning tools is the ability to optimise a portfolio of network and non-network solutions and technologies when deriving optimal network planning strategies. The first departure from the historical network planning processes towards achieving network security through both network redundancy and incorporating non-network solutions has been carried out in the UK and the authors of this report have developed network modelling tools to inform this process. Although the focus of this section is on presenting the concepts behind including distributed generation (DG) into distribution network planning, similar approaches are now being considered to be applied to flexible demand technologies, such as EVs.

This topic is particularly relevant in the context of the expected increase in the deployment of distributed renewable generation (primarily wind and solar, but also biomass, waste and other technologies), which is receiving strong incentives across Europe. An important technical issue here is the contribution that this new generation could potentially make to distribution network security. This section therefore presents the main features of the methodology for assessing the security contribution from distributed generation in distribution network planning.

Introduction

Security and customer reliability have always been of high priority to the electricity supply industry, with effort being made at both the planning and operational stages to ensure that the reliability is as high as possible commensurate with the cost of achieving it. In the UK in the 1970s, in order to create “consistency” between all distribution companies, distribution network planning and security standards were developed taking into account the probabilistic nature of system failures in a more formal way. Following a network failure, the related standard assessed the capacity contribution made by the remaining network connections together with the capacity contribution that could be associated with any embedded (distributed) generation.

To achieve this, the industry considered the Expected Energy Not Supplied (EENS) to be the most appropriate index for assessing reliability and hence security. One reason was that it was a severity index dependent on frequency, duration and load, and hence incorporated the three primary reliability parameters. It was also an index to which the electricity industry placed a monetary value, namely a reinforcement scheme could be justified if the implied cost was between acceptable limits.

Distribution network planning and security standards in the UK set not only technical but also legal requirements for Distribution Network Operators (DNOs)[32] to deploy appropriate levels of network capacity and redundancy. Hence the distribution network planners are obliged to follow these standards very strictly when designing distribution networks.

More recently there has been a growing interest in connecting various forms of distributed generation to distribution systems including renewables, such as wind energy conversion systems, photovoltaic generation (PV) or small hydro generation that are intermittent by

[32] They correspond to DSOs in other jurisdictions.

nature. This development created the need to consider the extent to which different forms of distributed generation could provide a contribution to network security and offset the need for network reinforcements. The methodology presented here was applied to develop a new distribution network planning standard that now enables network planners to consider contribution of various forms distributed generation, including intermittent renewables, to distribution network adequacy.

Methodology

Two specific principles were followed when developing the methodology: (i) the approach had to be simple and easy to implement; and (ii) it had to be consistent with that used to develop the conventional generation contributions specified in the existing network planning and security standards, i.e. based on EENS as the reliability criterion. The objective was to permit an extensive set of plant and system attributes to be considered and reflect all types of modern generating units and operational modes including renewable and intermittent energy sources.

The purpose of the network planning and security standards is to ensure acceptable levels of security in distribution system following specified circuit outages. This is achieved by considering specific load groups and aggregating all the loads supplied by that group, both at the same voltage level and lower voltage levels. The aggregated load is known as the group demand (GD). The standard does not consider the network structures associated with a particular load group, only the aggregated demand within it.

The standard essentially consists of two tables:

- **Table 1** specifies the maximum reconnection times following pre-specified events leading to an interruption. This time is dependent on the GD affected by the interruption.
- **Table 2** specifies the security contribution that can be credited to conventional embedded generation (i.e. coal-fired generation). This contribution is added to the cyclic rating of the remaining circuits and the transfer capacity of alternative sources. If the total capacity equals or exceeds GD then that load group is compliant with the standard.

The basic principle of the new methodology was to determine the capacity of a perfect circuit which, when substituted for the DG, gives the same level of EENS. This capacity is the effective contribution of the generation system and represents the “effective contribution of generation” or simply “effective generation” that can be relayed on. Clearly, DG will only contribute to network security if it is available when required. Therefore, the following conditions are required to include DG in security considerations:

- The generator must be in working state, i.e. it must not have failed. This is defined as technical availability and can be captured using capacity outage probability tables.
- There must be a source of primary energy, e.g. gas for CHP, wind for wind generators, etc. The most important area of concern is with wind plant and the intermittency of the wind regime. This is defined as energy availability or persistence.
- It must be commercially advantageous to the generator owner/operator to run the plant. Present-day generating plant is privately owned and therefore its use for network support may be restricted for commercial reasons. This generally means that

the generator must be given financial incentives to be available and to deliver when needed. This is defined as commercial availability.

Non-intermittent generators

In order to decide the appropriate approach for modelling both non-intermittent and intermittent generation in the context of their security contribution, it is necessary to outline the concept underpinning the new distribution network planning / security approach. In the case of non-intermittent generation (NIG), e.g. landfill gas or CHP plant, this is achieved by comparing the reliability performance of generation with a perfect network circuit using EENS as the reliability index, as illustrated in Figure A2.1. Given the assumption that the line is 100% reliable, the comparison is achieved by adjusting the circuit capacity so that the same EENS is achieved (i.e. the equivalent circuit capacity will be lower than the peak demand, as discussed below in more detail)

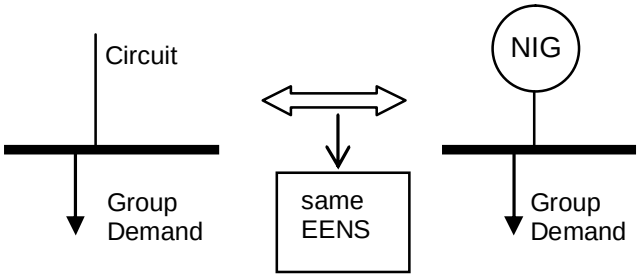


Figure A2.1 Comparing non-intermittent generation (NIG) with circuit

The basic tool for assessing the reliability of independent non-intermittent generators not constrained by energy availability is the *Capacity Outage Probability Table* (COPT).[33] The most common approach to load modelling for security assessment is the *Load Duration Curve* (LDC), as it enables both energy and EENS to be determined from the area under the curve as shown in Figure A2.2.

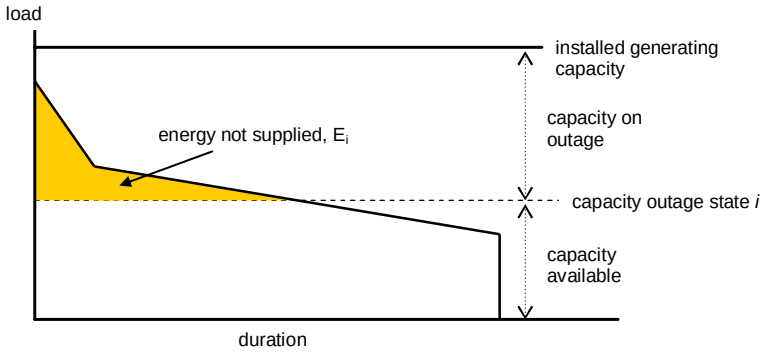


Figure A2.2 Evaluating energy not supplied for a generating system

The EENS associated with the given generation system is then evaluated as follows:

[33] The detailed theory behind COPT is given in various reliability textbooks, such as e.g. R. Billinton, and R. N. Allan, "Reliability of power systems", 2nd ed., 1996. Plenum Publishing, New York.

- Each state of the COPT is superimposed on the LDC individually as shown for one state *i* in Figure 5.2.
- The energy not supplied E_i whilst in this capacity state is determined as the area below the LDC and above the capacity available.
- This value of energy is weighted by the probability of being in this capacity state, p_i.
- These weighted values of energy are summed up over all capacity states to obtain EENS: EENS = $\Sigma_i p_i E_i$.

The effective circuit capacity (i.e. effective generation) that would create an identical value of this EENS is found iteratively by moving the capacity level up and down the LDC until reaching the value that results in the same EENS.

Intermittent generators

The COPT-based approach used for modelling non-intermittent generation uses technical availability as the only unit reliability parameter. This availability however is a measure of the total time the unit is found in the up state during an annual (or other specified) period. A given availability may be due to a small number of up states of long duration or a large number of up states of short duration. If the up-state durations are very short, then the state of the unit may change during the time it is required to operate, i.e. possibly during the time it is satisfying security demands. If this occurs then the unit may fail to provide the level of security expected of it. An example for this is the output of wind power units, which can vary significantly over very short periods. These frequent output variations require extended modelling principles, and require considering energy availability as well as technical availability.

Furthermore some units in the system may not be available at certain periods or on a continuous basis due to commercial reasons and this may also create a form of intermittency. This may occur with CHP plants that are switched on and off or their output is increased and decreased due to the energy demands of the owner. In such cases the unit(s) may become unavailable when required or during the period when they are being used to provide security.

Effective generation of intermittent generators is evaluated using the same approach as for non-intermittent generation, i.e. by determining an equivalent circuit capacity giving the same level of reliability (based on EENS) as the generation source with which it is being compared. The intermittent generation model has to reflect energy and commercial availability as well as technical availability.

The only practical approach to deal with the chronological variations in intermittent generation output, whether random or certain, is to characterise the variable as a time-varying parameter with its chronological behaviour fully represented. A schematic illustration of a generation pattern is shown in an example in Figure A2.3, in which the load is assumed constant (for simplicity purposes). This chronological pattern captures all three types of availability; technical, energy and commercial availabilities, and hence is a suitable base model for representing the capacity states of the generation. Detailed knowledge of individual units, capacities, availabilities, etc. is therefore not required. In the case of multiple wind farms connected to the same demand group, the outputs of the individual farms should be aggregated and used as the chronological generation pattern. This enables diversity within and between sites, to be taken into account.

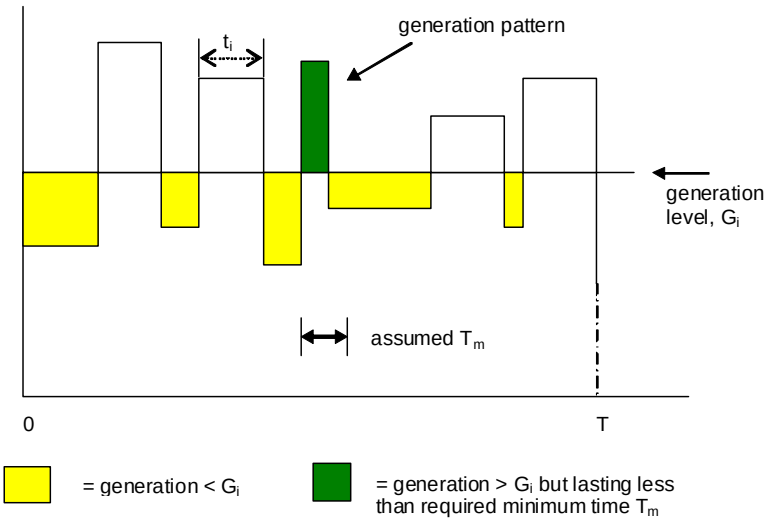


Figure A2.3 Availability model for intermittent generation

The main difference between modelling non-intermittent and intermittent generation is in those periods of intermittent generation that do not persist for a required minimum period of time, and hence must be discarded from the assessment. It is assumed that this minimum time is T_m. The steps in the assessment process are then:

- Identify the time dependent generation pattern
- Consider a generation level G_i
- Identify the occasions when "the generation is at least equal to G_i and continues to remain at least equal to G_i for the minimum time T_m". These are the "good" or "up" states
- Count the number of times, n_i, that this occurs and the duration, t_i, of each of these occasions
- Therefore, if T is the total time period of the generation pattern, the probability that the generation is at least equal to G_i is given by $P_i = \Sigma_i n_i t_i / T$
- This can be repeated for all generation levels between the lowest and highest generation levels, from which a generation model identical in concept to a multi-state capacity outage probability table can be determined. Each capacity state is given by G_i and the state probability by P_i and all states are mutually exclusive. These states are then imposed on the LDC in the same way as for non-intermittent generation.

It is important to note that any form of generation can be treated as intermittent. It follows therefore that wind plant and CHP plant can both be modelled and assessed using the same approach. The only difference is that the output of wind plant may vary more rapidly and with greater fluctuations than CHP plant. However this does not affect the concept, only the actual generation contribution and this will reflect the actual input data. It also follows that the approach could, in principle, be applied to any form of generation since all generators are subject to changing output, if only because of technical unavailability. However, if the average time between changes of state is much larger than the time for which the units are required to satisfy security constraints, then these additional modelling techniques are not necessary.

Application examples

Contribution of non-intermittent generation

Based on the number of units, their availabilities and capacities, the first step involves forming the COPT for the group of non-intermittent generators. An appropriate LDC is then superimposed onto the COPT and the EENS is calculated. Finally, the effective generation contribution is determined from the circuit capacity which, when substituted for this generating plant, results in the same level of EENS.

The LDC used to carry out the illustrative case studies is shown in Figure 5.4 (left). The resulting security contribution of a given number of non-intermittent generators is shown in the right-hand side of Figure A2.4. As expected, the results show that the contribution increases as the number of units is increased, although the relationship is not linear. The contribution of a single generating unit is about 50% of its capacity, while for 10 units the contribution is greater than 75% of the total capacity. It is important to observe that the security contribution made by a generating system is always less than the availability of a single unit (in this case 86%).

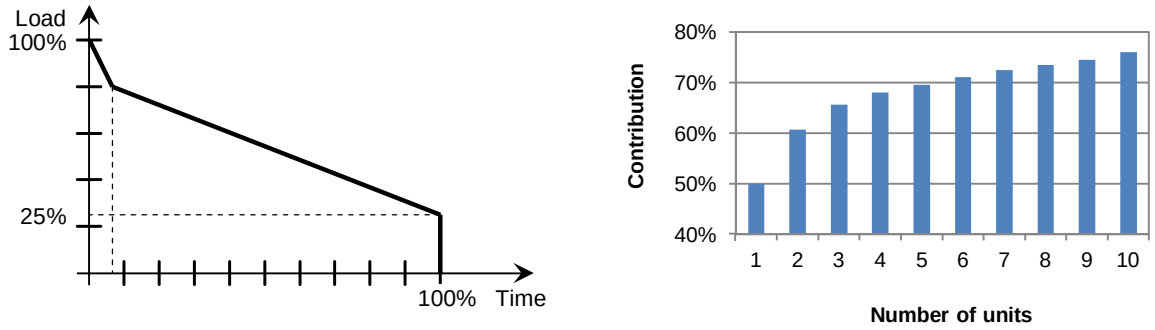


Figure A2.4 Application of the methodology to non-intermittent generators

An example of the application of the proposed methodology to calculate the network capability is shown in Figure A2.5. The local group demand is supplied from a system composed of two transformers operated by the local DSO, two generators operated by Generating Company A and one generator operated by Generating Company B. The capacities of the transformers together with availabilities and capacities of the generators are given in Figure A2.5.

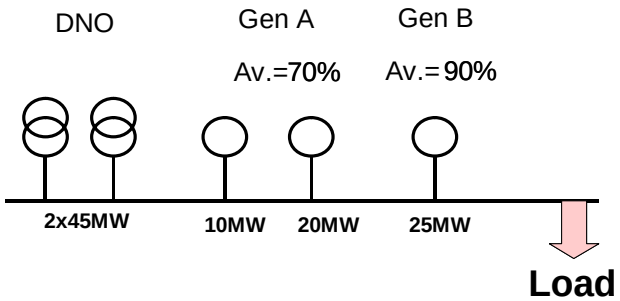


Figure A2.5 Distribution system example

The associated COPT for this generation system is:

Capacity (MW)	55	45	35	30	25	20	10	0
Probability	0.441	0.189	0.189	0.049	0.081	0.021	0.021	0.009

Superimposing this COPT onto the LDC in Figure A2.4 gives the contribution that these three generators can make to network security of 34.51 MW. The capability of the system after an outage of one transformer is therefore:

- The remaining transformer has the cycling rating factor of 1.3, and is therefore capable of carrying 1.3 x 45 MW = 58.5 MW
- The overall contribution of the three generators is 34.51 MW (or 62.82%)
- Total network capability is therefore 93.01 MW

If the peak demand of the group is below 93.01 MW, the system would be considered to be compliant with the UK network planning and security standard.

Contribution of intermittent generation

Given the output profile (over one or more years) of an intermittent generator system, e.g. wind farm or small hydro, and the required persistence level (T_m), the corresponding COPT is first formed. Then, as in the case of non-intermittent generation, the appropriate LDC is superimposed on the COPT and the EENS calculated. Finally, the effective generation contribution is deduced as the transmission circuit capacity which, when substituted for the generating plant, gives the same level of EENS.

The methodology was applied to a wind farm having the normalised half-hourly profile output shown in an example in Figure A2.6 (left). For a number of persistence levels from 0.5 hr to seven days, the corresponding COPT was created using 20 discrete output states. The contribution of the wind farm to system security was then quantified and the results are shown in Figure A2.6 (right) with the levels of contribution for 1 min and for 30 min resolutions. As expected, the apparent contribution of wind reduces if the 1 min data is used. For T_m = 0.5 hr, the contribution of the wind farm to network security is about 30%. Increasing the level of required persistence reduces the contribution to security: for T_m = 24 hr the contribution reduces to about 15%.

In the context of the UK distribution network planning and security standards, it is important to note that the tangible security contributions of wind generation are limited to relatively short persistence levels T_m. In other words, the effective contribution of wind generation is between 10% and 20% of installed capacity for T_m < 24 hr. This demonstrates that wind generation could support the distribution network during network reconfiguration activities, but not displace significant amount of network capacity.

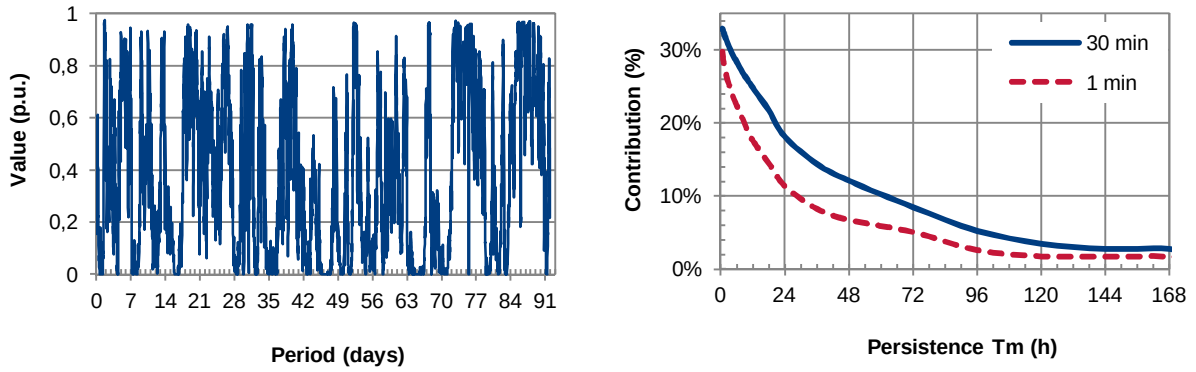


Figure A2.6 Normalised winter output profile of wind farm (left) and the effect of persistence level on security contribution for different time resolutions (right)

Implications for future distribution network planning and functionality of future planning tools

The methodology described in this section was used to develop new distribution network design standards, which for the first time included the contributions on non-network solutions to network planning by quantifying the contribution to network security offered by both non-intermittent and intermittent generators. Each DNO in the UK is now obliged through its licence to adhere to this standard when planning distribution networks and assessing the security of its network.

The approach to assessing the security contribution of intermittent generators, by looking at their chronological operating profiles, could be further extended to include various types of flexible electricity demand (such as flexible EV), as well as different forms of energy storage. The framework outlined in this section, used to quantify the security contribution of generators, could conceptually also be applied to other non-network solutions, after giving careful consideration to their specific operating constraints, such as the energy requirements and flexibility to shift demand in time. Furthermore, future network planning tools will need to accommodate the reliability performance of the ICT infrastructure that will be essential for future network operation as the present planning tools do not consider ICT explicitly in distribution reliability assessment.