Advanced Architectures and
Control Concepts for

MORE MICROGRIDS

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DH2. Report on economic, technical and environmental benefits of Microgrids in typical EU electricity systems

WPH. Impact on the Development of Electricity Infrastructure

TH2. Quantifying the impact of Microgrids on investment and replacement strategies of future national electricity infrastructure

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Executive Summary

This Deliverable report contains the main findings from the work carried out for Task TH2: "Quantifying the impact of Microgrids on investment and replacement strategies of future national electricity infrastructure", which is the core of Work Package H (WPH) of the More Microgrids project. In particular, a number of models and relevant studies have been carried out to investigate the potential impact and benefits of Microgrid operation on different power system areas of interest, ranging from distribution networks to conventional generation operation and expansion, with specific reference to typical European scenarios.
The Deliverable is composed of a main body (the present document) and four Annexes. The types of analysis performed, the models and tools developed, and the results obtained are synthetically presented below.

Distribution network studies

In order to quantify the distribution network capacity that could be displaced by micro-generation operating in Microgrids, Imperial has developed the so called Generic Distribution System (GDS) model, enabling to represent typical European distribution networks designed in top-down hierarchical structure. In particular, by analysing multiple voltage levels, technical, economic and environmental impacts of Microgrids on a system level can be studied. The tool is based on radial load flow analysis based on typical generation and load patterns, which allows a better understanding of the relevant drivers for benefits. The models has been populated by real network data provided by partners for selected Northern and Central European countries, namely, FYROM, Germany, Netherlands, Poland, UK, with DG largely characterized by Combined Heat and Power (CHP) systems. Given the large variety of characteristics, comparison among the different networks has enabled to strategically highlight common trends and differences.

The main focus of the analysis has been on estimating the reinforcement requirements to accommodate Distributed Generation (DG) due to voltage, thermal or fault level issues, as well as the potential benefits owing to postponing the need for upgrading network capacity to accommodate load growth. Within this scope, different strategies for Active Management (AM) of the network at different voltage levels have also been considered, consisting of coordinated control of on-load tap changers, reactive power control and generation curtailment where needed. In particular, AM strategies have been compared to a classical fit & forget (passive management - PM) approach, so as to highlight the need and benefits of controllability both in Microgrids and at higher voltage levels. This type of studies have been carried out through a Cost Benefit Analysis (CBA) approach, whereby potential benefits have been evaluated against potential additional operational cost (namely, losses) and the cost of infrastructure required to implement intelligent control strategies (communication infrastructure, automatisms, and so on). In this regard, typical cost for the needed communication infrastructure has been identified. A crucial outcome of the comparison among different networks and network management strategies in the presence of DG has been that benefits and impacts, as well as mitigation actions and further benefits brought by AM actions, are strongly related to the strength of the network.

The studies based on the GDS model have been divided into two groups according to the scenarios examined, the temporal basis and the methodology undertaken for network development evaluation.
The first stream of analyses has been based on the data provided by the project partners regarding the envisaged demand and DG penetration at all voltage levels in a number of future snapshots. In this case, a dynamic assessment for network development has been carried out taking optimal decisions on network investment including selection of AM strategies at different milestone times across the provided scenarios. A schematic flow of the methodology comparing the case with and without DG is shown in Figure A.1.

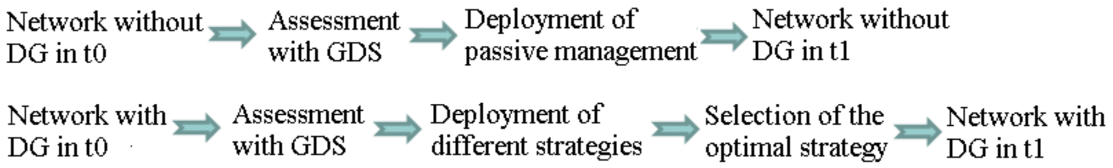

Figure A.1. Dynamic network assessment model.

The second stream of analyses is more specific to Microgrids (consisting of a mix of Micro-CHP and Micro-PV systems) and has involved studies of the impacts of micro-DG and AM based on the current distribution networks (static assessment). This allows a straightforward quantification of the sensitivity of Microgrids impacts with respect to the level of micro-DG penetration (high and low) and of demand (high and low) at LV has been quantified.

From the different types of analysis run, some key outcomes have been identified, as summarised below:

- The contribution of micro-generation to decreasing upstream power flows leads to: *substantial value* (in terms of capacity release) in the Polish, FYROM, and UK networks, where reinforcement is demand-driven; *zero value* in the very strong Dutch network; *negative value* in the (also quite strong) German network, where the envisaged DG penetration is likely to create fault level problems.
- In a similar manner, although the effect of DG on *losses* was beneficial in most cases, there are situations in the Dutch network where DG creates significant reverse power flows and increases distribution losses.
- For relatively weaker networks (Poland, FYROM, UK), in those cases where a part of the required reinforcement is related to voltage problems the application of active management reduces significantly the reinforcement cost (in Figure A.2 the case with PM is even negative since voltage rise due to DG calls for network reinforcement relative to the case without DG), at the expense of higher losses in the network (Figure A.3). This is due to the higher network exploitation enabled by AM, while in the PM case the feeders are upgraded and thus the losses decrease.

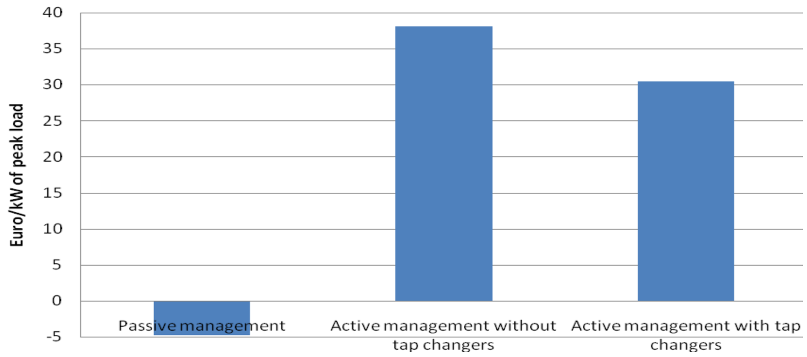

Figure A.2. Example of reduction in reinforcement cost owing to DG under different management strategies between two scenario snapshots (Poland).

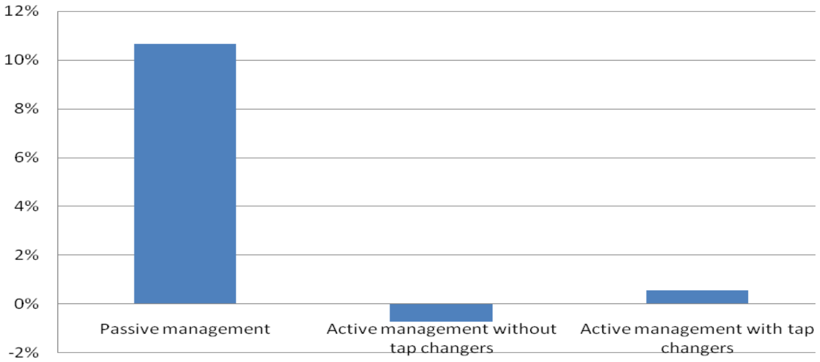

Figure A.3. Example of reduction in losses (in percentage of the base case) owing to DG under different management strategies between two scenario snapshots (Poland).

- In every case that AM is deployed, its overall effect on the total network cost is positive, since the positive impact on reinforcement cost is much higher than costs of losses and implementation. The overall network cost can thus be computed as sum of reinforcement and losses costs, which can be used as a measure of the value of DG for the Distribution Network Operator (DNO). This is for instance reported in Figure A.4 for different levels of DG penetration and for a scenario characterized by low load, in correspondence of the optimal network management strategy found.
- A substantial difference can be appreciated between the potential benefits of Microgrids on the relatively weaker distribution networks of Poland, FYROM and UK and the relatively stronger distribution networks of Germany and Netherlands. More specifically, while in the former there is significant room for Microgrids to reduce the total network cost, and this change with the penetration level, the positive or negative network impact is marginal in the latter (Figure A.4).

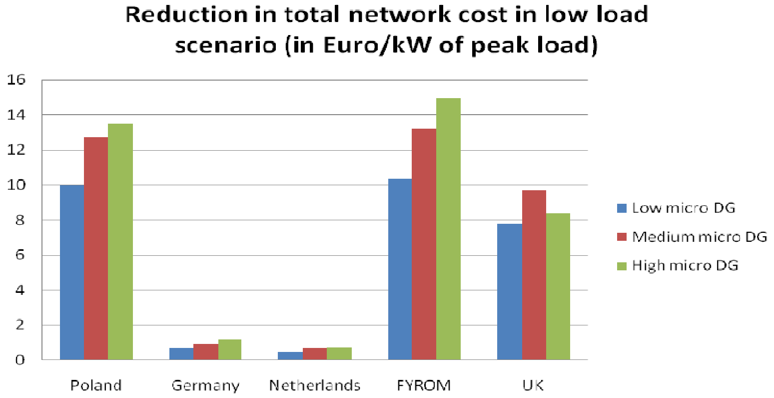

Figure A.4. Comparative impact of Microgrids on total network cost (reinforcement and losses).

Analyses relevant to Southern European scenarios, with large presence of PV systems, have been carried out by NTUA for Greece and by ERSE for Italy to complete a comprehensive picture of different scenarios across Europe. In particular, in the Italian case the impact of PV-based Microgrids on MV network investment has been assessed at the design stage through different planning strategies, namely: a) PM; b) probabilistic, with load and generation hourly profiles; c) considering AM options at a design stage. The results from the analysis confirm the GDS results for the other countries, yielding that conventional PM planning approaches lead to higher investment costs due to (worst case-driven) over-sizing of lines and transformers. On the other hand, if the possibility to resort to AM options (in this case based on Demand Side Management – DSM – actions) is considered during the planning process, reduction in investment costs can be observed, although at the cost of energy losses. If a completely energy-autonomous Microgrids (resulting in zero active and reactive power flows at the MV/LV substation transformer), can be set up, further reduction in network upgrading costs and electricity losses can be achieved. These results are summarised in Figure A.5.

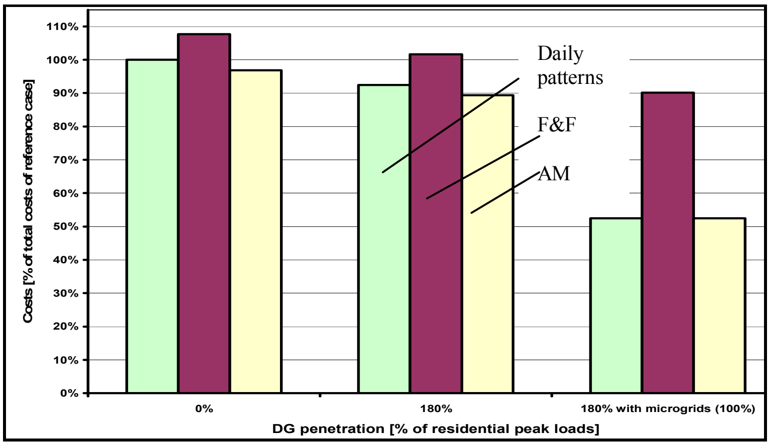

Figure A.5. Comparison of total costs under different planning strategies.

Further network development studies have been run by Imperial through a *generic distribution network model* based on *fractal topology generation* in order to assess the potential contribution and value of micro-DG for greenfield network design of typical urban areas and rural areas in the UK. The results show that a large number of micro-sources whose after-diversity production profile is well correlated with the network demand can contribute significantly to reduce the need for network asset. More specifically, it clearly emerges how the main driver for benefits is the correlation between local generation and demand. Therefore, CHP systems can bring substantial benefits in Northern scenarios to help support local demand and saving upstream network asset, while the potential of PV is restricted in this sense, due to the scarce correlation with peak load (typically occurring in winter). Controlling dispatchable DG such as micro-CHP to modulate their generation pattern to adapt to the electrical demand can bring further benefits.

The order of magnitude of the overall network benefits (network asset and losses) relative to a base case in which the distribution network is designed without DG is shown in Table A.1, pointing out that while PV can contribute to network cost reduction by some 10% only (mostly owing to losses reduction), controllable systems can reduce the network cost by up to one third (corresponding to an annual network cost of about 11 £/kW of peak load). In particular, controllability can bring additional benefits up to 13% or some 4 £/kW of peak load, as further illustrated in Figure A.6, with the breakdown of cost reduction per voltage level. The network infrastructure savings due to reduced power flows can be substantial, with prevailing influence on transformers in urban areas and overhead lines in rural areas.

Table A.1. Overall value of DG in percentage of the no-DG case (urban network).

	DG penetration levels (%)					
Scenarios	0	10	20	30	50	100
PV	0.0	2.8	4.2	6.1	8.4	10.6
Uncontrolled CHP	0.0	4.7	8.3	12.0	17.3	23.7
Controlled CHP	0.0	5.5	8.7	12.7	20.1	**36.3**

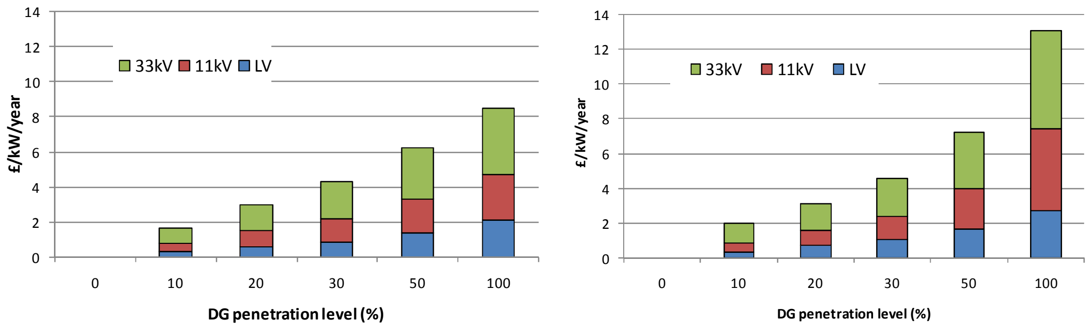

Figure A.6. Network value of uncontrolled (*left*) and controlled (*right*) CHP (UK urban networks).

While the absolute value of DG increases with the penetration (defined here as dwellings with micro-DG relative to overall dwellings in the network) level, its *specific value* normalized with respect to DG installed capacity decreases and saturates relatively soon (Figure A.7). It is however interesting to show how the value of controllability changes for different penetration levels, with the maximum value of controllability in the order of

50 £/kW$_{DG}$ in urban areas for 100% penetration level, while for rural areas the figure is in the order of 30 £/kW$_{DG}$ for penetration higher than 30%.

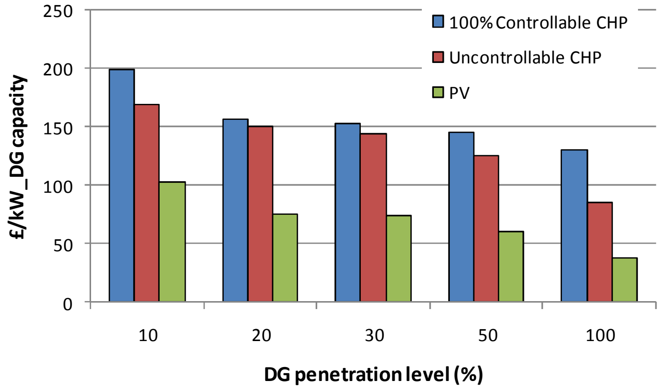

Figure A.7. Total network value of DG in urban areas per installed DG capacity.

Given the utmost role envisaged for CHP systems to meet European environmental targets, specific analyses have been run by Imperial to gain more insights on the drivers for benefits in the interaction between local electricity and heat demand and production in cogeneration. From the analysis on a UK urban reference network it has emerged that the main driver for environmental benefits is the adoption of technologies with high electrical efficiency and run under heat following mode. On the other hand, if these technologies are sized to satisfy the heat demand, it is likely that substantial electricity exports to the grid occur, whereas for technologies with smaller electrical efficiency a better compromise between network and environmental benefits can be expected. More specifically, for small penetration levels only benefits for both environmental and network criteria are likely to arise. For network deferral benefits, in particular, the annual value is in the order of 10÷15 £/kW of peak load for small penetration and rises to about 40÷45 £/kW for 50% penetration level, with minor impact of controllability. The upper level for network investment deferral is in the order of 55 £/kW, which reflects the value of the transformer asset at LV, and would further rise if network deferral for the upstream feeders were taken into account as well. However, for larger penetration levels counter-flows could potentially lead to need for network reinforcement. In this case, the adoption of controllability can help mitigate the need for network reinforcement by reducing the electricity export, although this would come at the cost of reduced environmental benefits due to cogeneration (which corresponds to passing from internalized environmental benefits of about 7÷14 £/MWhe to 4÷8 £/MWhe, based on a carbon cost of 10÷20 £/ton).

From the different analyses conducted, a number of *general conclusions* can be drawn about the impact of micro-generation and Microgrids on distribution network development:

- Benefits arise at low penetration levels of DG without significant drawbacks, while for higher penetration levels of DG losses can sometimes increase due to counter-flows, which could even lead to overtake circuit thermal ratings. In addition, voltage rise issues might arise as well in the presence of long (rural) feeders and high generation level uncorrelated with demand.

- Therefore, strong networks with overrated circuits and relatively short feeders can accommodate DG without significant problems while operation benefits hold, although sometimes not significant. On the other hand, weak networks with smaller circuit capacities and longer feeders may exhibit problems that might be significantly mitigated by DG (when problem are demand-driven), whereas on the other hand local generation might exacerbate voltage rise issues calling for network upgrade.
- For weak networks, at most penetration levels AM of different forms (generation curtailment, load controllability, adoption of on-line tap changer coordinated with reactive power control, and so forth), including in the Microgrid operational options, can help put off network reinforcement.
- Active network operation, which generally also includes coordination between Microgrids and the upper voltage level when problems occur at MV, typically leads to higher operational (mainly losses-related) costs due to higher (and more efficient) deployment of the existing asset. The trade-off of additional losses and cost of implementation of (optimal) AM strategies against network upgrade cost needs to be thoroughly assessed, according to the models illustrated. In the analyses run, the cost balance is always in favour of AM implementation.
- In terms of environmental benefits, the contribution of DG is significant owing to the clean technologies used, with the benefits due to clean energy production being at least one order of magnitude more than network benefits in terms of losses.

Transmission network studies

In order to identify the potential costs and benefits of Microgrids in terms of transmission network development, a general framework based on a CBA approach has been developed by Imperial to include DG into transmission planning, under the rationale that transmission investment should be optimised in the long run against the cost of congestion. In addition, an optimal generation/load scheduling model has been developed to identify the value of controllable loads aggregated within Microgrids for transmission purposes according to different criteria. Illustrative examples have been run based on the UK system. In this respect, although the results found are by nature case specific, the qualitative trend can be generalised to other cases. In particular, the models developed provide a solid ground to run CBA-based studies to assess the value of controllability of Microgrids for transmission, to be assessed against the cost of the relevant communication infrastructure needed.

Regarding the impact of DG within Microgrids for *transmission development*, a first realistic analysis has shown that, compared to the base case with no DG, intermittent DG (wind) could increase transmission cost by about £33/kW$_{DG}$. However, a combination of wind and CHP (with penetration of about one seventh of the network peak demand) compared with the base case could reduce the transmission cost substantially, by some £54/kW$_{DG}$. The impact of CHP on transmission is therefore even larger if wind scenario is compared with wind plus CHP scenario, with benefit of CHP translating into a value of £160/kW$_{CHP}$. This means that the CHP production profiles bring benefits in terms of transmission capacity and congestion release. The additional value brought by CHP increases by about one fifth if CHP can be optimally *controlled* within Microgrids, but does not change significantly after enabling 60% controllability, as shown in Figure A.8. The value of controllability is relatively modest compared with the benefits brought by CHP itself, but this could be expected since the network flows are still dominantly controlled using conventional generators.

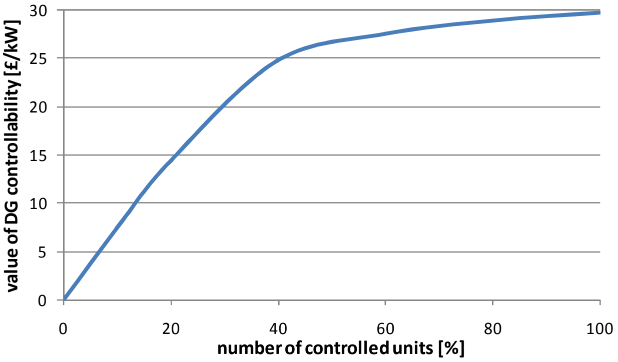

Figure A.8. Value of Microgrid-enabled micro-CHP controllability for transmission capacity release.

As far as *controllable loads* are concerned, the results in the case study run show that DSM enabled by Microgrids has an overall positive impact on network operation by reducing the total generation re-dispatch cost owing to congestion release, with an annual value attached to controllability varying from 34 to 9 £/kW of controllable load when the dispatchable load changes from about 2% to 8% of the peak load (Figure A.9). The decrease in the specific value per installed capacity of controllable load is due to the fact that there is saturation in the amount of energy that can be managed. This is a key characteristic of controllable loads with certain time-constraints, whose application is case specific and whose extent is limited by the relevant conditions.

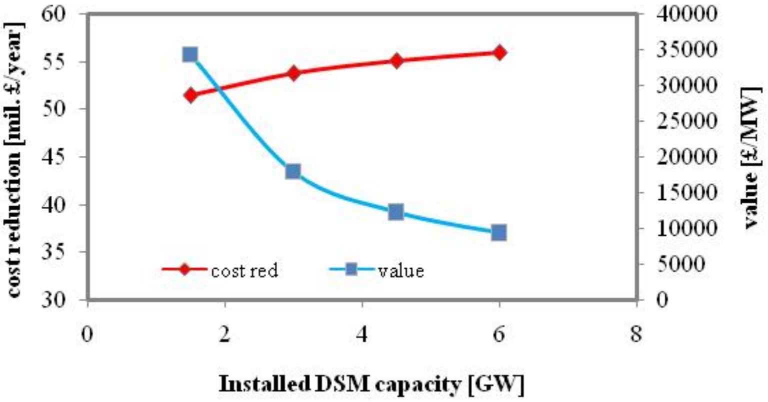

Figure A.9. Cost reduction from DSM enabled by controllable loads in Microgrids.

Generation studies

Different analyses have been performed to address the impact and the benefits brought by Microgrids with respect to conventional generation systems.

More specifically, two general types of analysis have been carried out, namely, relevant to identify the potential of Microgrids to support generation adequacy while keeping given level of security of supply, and to identify the value of Microgrids to support system operation and provide in case load balancing services.

In terms of *capacity adequacy*, detailed modelling has been performed by INESC, with an illustrative numerical example performed for the Portuguese case. The analysis confirms the previous network analyses, whereby the main driver for benefits is the correlation between micro-DG supply and (peak) demand. This leads to relatively high value of *capacity credit* (CC) for micro-CHP, in the order of 60%, which is consistent with values obtained in an estimate performed by Imperial for the UK for similar penetration levels. On the other hand, the CC of PV and micro-wind is relatively limited, equal to about 16% and 4%, respectively, due to the scarce correlation of their output with the occurrence of peak load. A further key conclusion from the results is related to the limited influence that the rated power and unavailability of the micro-generators has on the CC value.

Regarding more specifically Microgrids, the results show that integration of *controllable micro-CHP* systems within MG increases their CC, for example passing from 69% to 75% if 20% of these generators may be controlled by the action of Microgrids (Figure A.10). Similarly, significant CC may be obtained by *load controllability*. For instance, the control of 5% of the total system load enables to remove roughly 5% of the conventional generation capacity installed in the system. This confirms the strategic role that DSM actions enabled Microgrids could play in future system development.

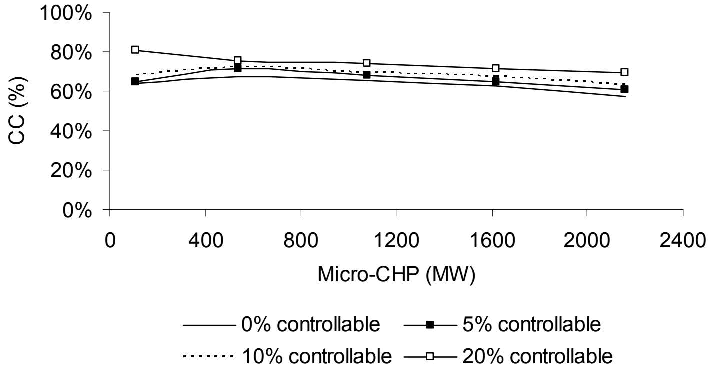

Figure A.10. Influence of Microgrid on the CC of micro-CHP systems.

From an *operational perspective*, if the level of clean intermittent (wind) and inflexible (nuclear and carbon capture and storage (CCS) plants) generation increases as expected, more value could be attached to flexible DG with high capacity credit. Therefore, a scheduling modeling has been developed by Imperial and has been specifically adapted to include micro-CHP, intermittent sources and must-run plants. A number of analyses have then been carried out to explore the value of micro-CHP, to be potentially controlled within Microgrids, in providing balancing services within systems with different flexibility levels. The key aspect of the model developed is the ability to capture the interaction among response, reserve and energy provision from different generators, including micro-CHP, taking into account their cost and emission characteristics.

The potential impact and value of Microgrids on the overall system performance was investigated with a number of different assumptions regarding the flexibility that Microgrids are able to provide to the system. More specifically, four different service provision regimes have been investigated, adding up on top of the other, moving from inflexible operation (heat following micro-CHP seen as negative load), to flexible energy balancing, to reserve provision, and ending with a regime where Microgrids are capable of providing a full range of system services, including frequency response. The resulting four operating regimes were simulated as part of the system scheduling model, varying certain parameters such as Microgrid penetration, wind penetration and system flexibility, to investigate the sensitivity of the impact of Microgrids on system operation under a range of circumstances that could occur across Europe.

As a common point, it has emerged that Microgrid-related benefits, expressed per unit of micro-CHP capacity, decrease with increasing Microgrid penetration because of a saturation effect. This discrepancy, which is consistent with the network analyses described above, becomes more evident with more flexible Microgrid operating regimes.

For a *highly flexible system*, the system value of Microgrids for systems with significant wind capacity is higher if Microgrids are able to provide flexible reserve and response services. Annual values for substituting electricity normally provided by conventional plants with distributed generation achieves around £80/kWe, and this remains the largest component of the overall savings, even for more flexible operating regimes. In the most flexible regime, the total annual savings can reach levels of around £100-£120/kWe to £120-£140/kWe for cases without and with wind, respectively. The main difference between the two cases appears upon introducing reserve provision from Microgrids, which provides higher value in the high-wind case.

For a *medium flexible system*, trends are rather similar as for the highly flexible case, although the level of savings is markedly lower here (roughly a half of the value for highly-flexible system), as a consequence of the cost assumptions made for conventional generators in the two system types. In relative terms, adding flexibility to Microgrids (especially balancing and reserve) adds more value in the case with wind, compared with the highly flexible system. In that case, total value in the most flexible Microgrid operating regime can reach almost double of the value of using Microgrids only to substitute electricity from conventional units. Starting from the annual value of around £40/kWe for the non-flexible case, the value climbs to £50-60/kWe for the no-wind case and to £60-70/kWe for the case with 20 GW of wind.

When looking at the cost saving profile for the *low-flexibility case*, most of the added value comes from Microgrids providing reserve services. In fact, because of a very low flexibility in the system (due to large must-run and wind capacities), adding inflexible micro-CHP profiles as a negative demand helps the system only slightly, since the remaining less flexible conventional units have an even more variable net demand profile to follow. The largest benefit for the system occurs when reserve provision from Microgrids is considered as an option. Providing reserve from Microgrids increases their system value by a factor of 2 to 3.5 (Fig. A.11). This largely results from releasing a large amount of conventional capacity which is normally used to provide this reserve, and this enables a more efficient operation of the rest of the system.

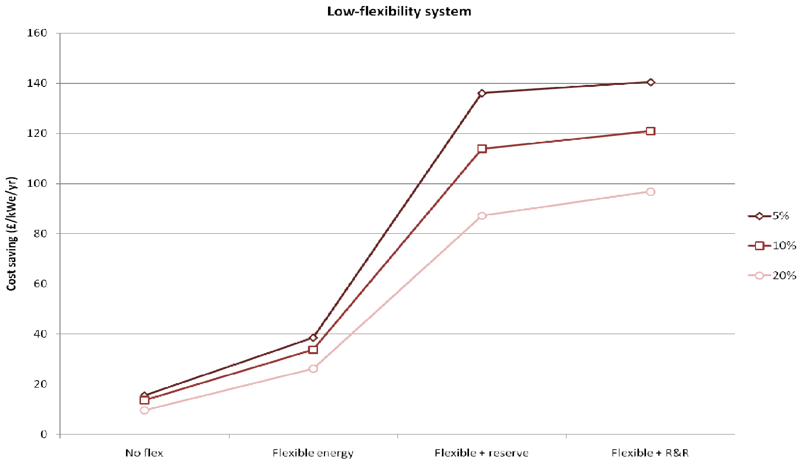

Figure A.11. Cost savings for the low-flexibility system.

Trends in *emission savings* are very similar to the ones for cost savings, since both cost and emission savings come from avoiding the usage of fossil fuels in conventional plants. Emission reduction in a highly flexible system is around 0.5-1 kg CO_2/kWe per annum. In the medium-flexibility case the emission reduction ranges between 2-3 kg CO_2/kWe, largely as a result of a higher emission factor assumed for medium-flexibility conventional generation (by a factor of around 2.5). In the low-flexible system, this value grows from around 1 to almost 5 kg CO_2/kWe, as flexibility of Microgrids operating regime increases.

As a further key point, it is of particular interest to investigate how the flexibility provided by Microgrids can contribute to *reducing the need to curtail wind output* in periods of high wind and low demand. This issue is especially important for situations with very high wind capacity present in the system, exemplified in the low-flexibility system (Figure A.12). In this regard, when operating in an inflexible operating regime (*i.e.*, heat following), micro-CHPs can actually aggravate the situation regarding wind curtailment, as their fixed output profile, when combined with high wind in periods of low demand, further reduces the net demand to be covered by conventional units in the system. This situation improves slightly with adding balancing flexibility to Microgrids, while a major improvement appears when Microgrids are allowed to provide reserve services (and replace reserve provided by conventional units). In their most flexible operating regime, Microgrids can contribute to reduce curtailed wind output by 0.3-0.8 kWh/kWe, and enable more efficient integration of intermittent wind output.

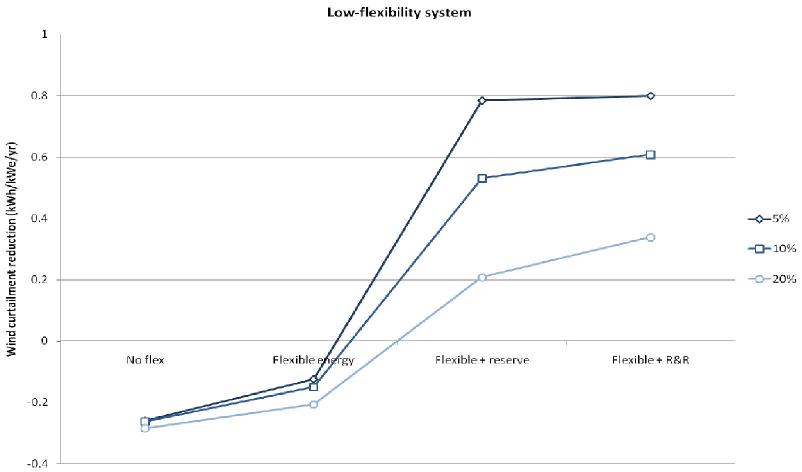

Figure A.12. Wind curtailment reduction for the low-flexibility system.

By focusing on the *incremental value* brought by adding *flexible service capabilities* to Microgrids operation, for instance for a highly flexible power system with 5% penetration rate of Microgrids, the majority of the system value is contributed by using electricity from micro-CHPs in the first place. The reserve component of the value becomes significant in case with higher wind penetration (Figure A.13), passing from about 20 to about 40 £/kW$_{DG}$/year, due to higher reserve requirements to conventional generators in such conditions that are displaced by micro-CHP. For a medium flexible system, the overall level of savings is lower (due to overall lower fuel cost from the generation portfolio), but the weight of the additional value components for system services provision is comparable to the highly flexible case.

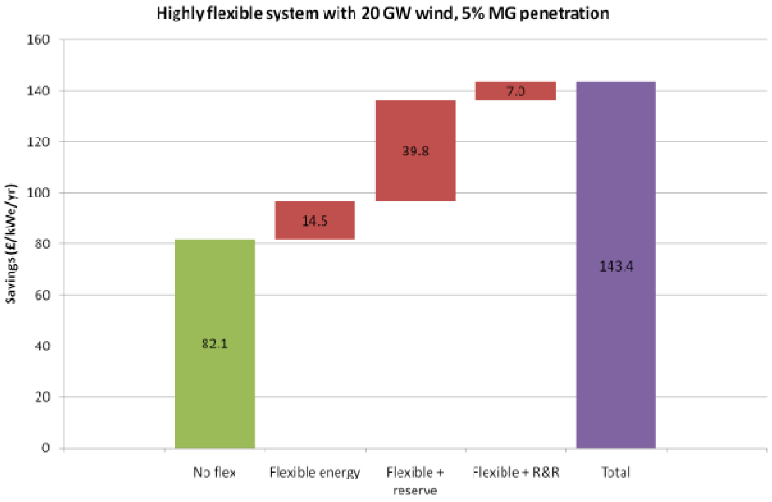

Figure A.13. Incremental components of system savings for the highly flexible system.

In the *low-flexibility* system, the majority of the value comes from providing reserve services. Indeed, flexible reserve provision is of great value in this kind of system, since the generation portfolio exhibits relatively inexpensive energy, but very little operating flexibility. This additional flexibility also allows higher deployment of intermittent renewable sources. In fact, while an inflexible operating regime (*i.e.*, heat following) for micro-CHPs can actually exacerbate the volume of wind curtailed to provide system balancing, the situation improves slightly with adding balancing flexibility to Microgrids, and a major improvement appears when Microgrids are allowed to provide reserve services (and replace reserve provided by conventional units). In this regard, controllability of small-scale flexible units does not only provide cheaper alternative to conventional generators to provide flexibility, but also allows larger integration of renewable sources, as mentioned above.

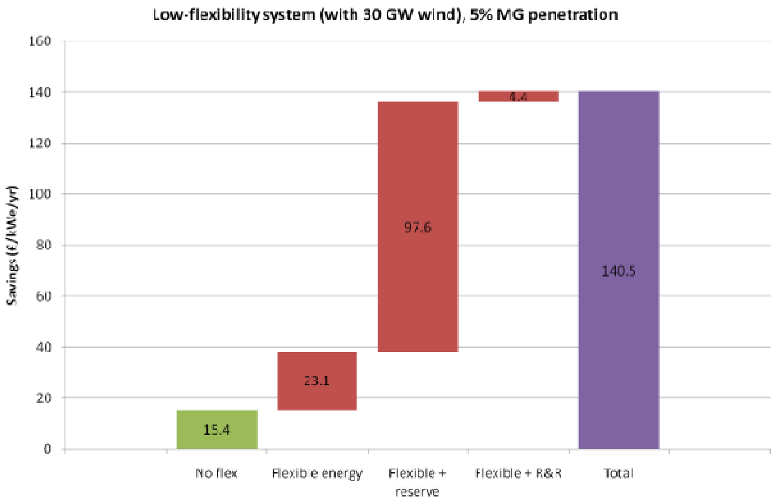

Figure A.14. Incremental components of system savings for the low-flexibility system.

Using Microgrids replaces a portion of electricity otherwise generated by conventional units, but it also reduces the need for conventional capacity in the system. Hence, by observing the maximum utilised conventional capacity within one year in cases with and without Microgrids, it is possible to provide a rough estimate of how much conventional capacity could be displaced by Microgrids in particular configurations.

The results generally indicate that no significant discrepancies exist in terms of how much conventional capacity could be displaced by Microgrids for different system types and with or without wind. As a representative example, Figure A.15 indicates how much capacity the Microgrids could displace in a system with no wind, for a range of operating regimes and Microgrid penetrations. The displacements are shown along with the actual total capacity of micro-CHPs, for the sake of comparison. The ratio of displaced conventional capacity to installed CHP capacity could thus be somehow interpreted as “economic capacity credit” as opposed to the classical capacity credit from security studies. According to the figure, the inflexible operating mode of Microgrids is only able to displace conventional generation for a part of the installed micro-CHP capacity (some 45-60% of it, depending on the penetration), with larger penetrations displacing relatively less capacity due to the saturation effect. When flexible energy provision by Microgrids is introduced, the displaced capacity increases approximately to the level of installed micro-CHP capacity. This is mainly because in this regime the flexibility of Microgrids allows for the flattening of the load diagram seen by conventional units, *i.e.*, reducing the net peak to be covered by large-scale generators. Adding further flexible services to

Microgrids, although improving the operational economic and environmental performance of the system, does not seem to displace any further conventional capacity (most of the displacement potential has already been exhausted by allowing for flexible energy provision). Although approximated, the studies provide results in the same order of magnitude of other more refined capacity adequacy analyses, and can thus be used to provide useful first hand indications of the impact of different Microgrid operating regimes.

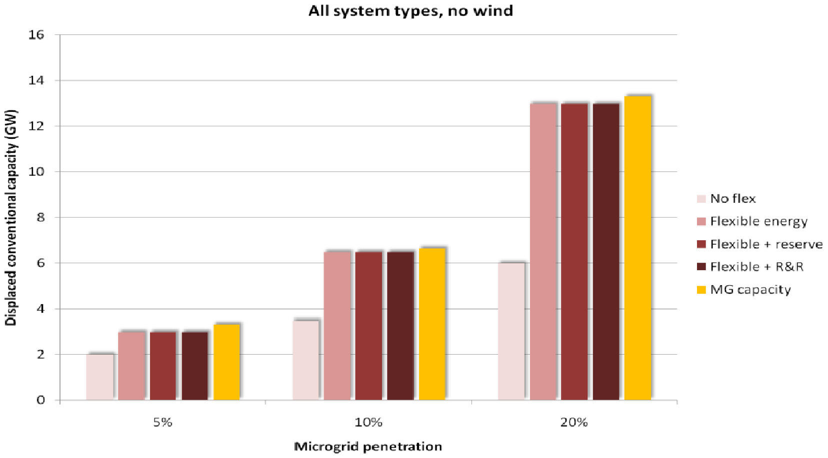

Figure A.15. Displaced conventional capacity as a result of using Microgrids in systems without wind.

It must be highlighted that certain cost saving figures as obtained from generation analysis may seem rather attractive, up to one order of magnitude higher than the network benefits highlighted above. This is a direct consequence of the potential of exploiting highly flexible micro-scale systems, with very fast dynamics and with an equivalent low production cost owing to cogeneration production allowing for discounting the quota of fuel cost allocated to electricity. However, besides these assumptions, it should be considered that a number of potential constraints such as local (network) constraints, availability of the units to provide services, minimum operational requirements, and so on, haven't been included in the analysis at first instance, so that the results tend to be optimistic. Nevertheless, clear indication emerges on substantial potential value of Microgrids to contribute to system flexibility above all in the large presence of wind and must-run conventional units.

A further economic estimate based on the computed conventional generation capacity that is displaced by Microgrids has been carried out to give an idea of the economic magnitude of the capital cost benefits to be traded off against the installation cost of micro-CHP, besides the above analysis on operational benefits.
Considering typical cost figures for the conventional generation technologies adopted, for the *highly flexible system*, annual savings in investment costs are between £25 and £32/kWe for the inflexible regime, and around £50/kWe for flexible operating regimes. The specific savings per kilowatt of electrical capacity do not change significantly with different Microgrid penetrations. Again, no marked discrepancies occur between cases with and without wind.

In the *medium flexible system* cost savings are higher due to the higher investment cost assumption. Inflexible operating regime in this case brings between £40 and £52/kWe of savings in annualised investment cost, while flexible regimes achieve between £80 and £90/kWe of avoided cost (Figure A.16). The same level of avoided investment cost as in the medium-flexibility case would be obtained for the *low-flexibility* case, and is therefore not shown separately.

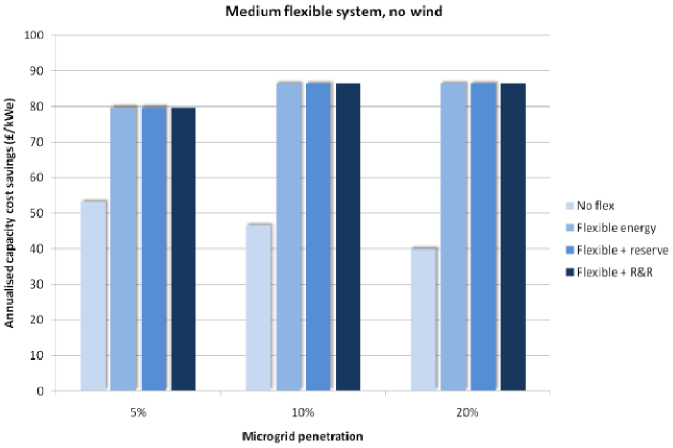

Figure A.16. Annualised savings in investment cost of displaced conventional capacity for the medium flexible system.

The level of savings achieved through avoiding the cost of building conventional capacity is considerable and of similar order of magnitude as savings in operating cost. These capital cost savings would obviously need to be compared to installation cost of micro-CHPs to obtain a correct picture of net benefits with respect to investments in decentralised rather than centralised capacity. In any case, the value of displaced capacity changes significantly if Microgrids can provide system services.

Based on the results shown above, there is significant potential for Microgrids to contribute to a more economical and sustainable operation of current electricity systems. They can provide these benefits through either providing cleaner and less expensive electricity, or providing flexible system services such as balancing, reserve and response. In particular, the value of providing system services increases with the share of must-run or intermittent renewable generation. In addition, Microgrids have the potential to displace not only the energy produced by conventional plants, but also some their capacity. This analysis, although approximate (availability performance of conventional generation as well as of micro-CHPs were all assumed to be 100%), suggests that Microgrids operating in *flexible regimes* are capable to displace conventional capacity in the amount roughly equal to installed micro-CHP capacity.

Contents

ACRONYM LIST

AM	Active Management
BAU	Business As Usual
CBA	Cost-Benefit Analysis
CC	Capacity Credit
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CO2ER	CO_2 Emission Reduction
DG	Distributed Generator
DH	District Heating
DNO	Distribution Network Operator
DSM	Demand Side Management
DSO	Distribution System Operator
ESP	Electrical Separate Production
FC	Fuel Cell
FESR	Fuel Energy Savings Ratio
F&F	Fit-and-Forget approach (or passive management – PM – approach)
FL	Fault Level (short circuit capacity)
GDS	Generic Distribution System
GSP	Grid Supply Point
GT	Gas Turbine
HV	High Voltage
ICE	Internal Combustion Engine
ICT	Information and Communication Technology
LCC	Life Cycle Cost
LHV	Lower Heating Value
LV	Low Voltage
MG	Microgrids
MX	Mixed (cables/lines)
MT	Microturbine
MV	Medium Voltage
NPV	Net Present Value
OH	Overhead (lines)
PM	Passive Management
PV	Photovoltaic
PW	Present Worth
RES	Renewable Energy Sources
SP	Separate Production
TSO	Transmission System Operator
TSP	Thermal Separate Production
UG	Under-Ground (cables)
VPP	Virtual Power Plant

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1. Introduction

Power systems were originally developed in the form of local generation supplying local demands, the individual systems being built and operated by independent companies. During the early years of development, this proved quite sufficient. However, it was soon recognized that an integrated system, planned and operated by a specific organization, was needed to create an effective system that was both reasonably secure and economical. This led to the development in most European countries of centrally located generation feeding the demands via transmission and distribution systems. Back to that time, a significant amount of local generation was left isolated within the developing distribution systems, but this was gradually mothballed and subsequently decommissioned so that, by the 1970s, most of it had disappeared from the electricity supply industry. This trend may well have continued for the need to minimize energy use, particularly the one believed to create environmental pollution. Consequently, governments and energy planners have more recently been actively developing alternative and cleaner forms of energy production, these being dominated by renewable (wind, solar, etc.), local CHP plant, and the use of waste products. Paradoxically, economics and the location of the fuel and/or energy sources have meant that these newer sources have had to be mainly connected into distribution networks rather than at the transmission level. A full circle has therefore evolved with generation being ‘embedded’ in distribution systems and ‘dispersed’ around the systems rather than being located and dispatched centrally or globally [1]. Over the past decades, models, techniques and application tools have been developed that recognized the central nature of generation. However, some very specific features of local Distributed Generation (DG), namely, those relatively small amounts of generation dispersed around the system and connected to (often relatively weak) distribution networks, need to be adequately addressed. In particular, the fact that DG is not usually dispatched by the network operator has meant that existing techniques and practices have had to be reviewed and updated to take these features into account [2]. In this outlook, while mostly benefits may arise for a small penetration level of DG whereby small generators can be seen as negative loads from the network perspective, larger shares of uncontrolled embedded generators in distribution networks, with different load pattern characteristics and often intermittent, may pose serious challenges for the operation and infrastructure development of power systems, as already partly explored in Deliverable DH1 [3] and detailed in the sequel of this work.

In a centrally planned (“conventional”) power system, demand and supply balance is typically maintained through provision of sufficient flexible/controllable generation that keeps the system frequency within desired limits to ensure the correct operation of the system. However, in the future the maintenance of system integrity may become more challenging due to the reduced presence of conventional (flexible) large scale generation leaving room to more intermittent Renewable Energy Sources (RES), above all wind and Photovoltaic (PV), as well as “clean” but inflexible large-scale generation such as nuclear and Carbon Capture and Storage (CCS) power plants. Therefore, a crucial point of the development of electricity infrastructure in terms of frequency-related ancillary service provision (namely, reserve and response) is to understand how and to what extent part of the system control measures could come from new non-conventional dispersed generation units as well as from active and controllable demand. Indeed, without the contribution of DG and responsive demand into the system operation activities, a larger proportion of conventional generation will have to be retained as system reserve, leading to increasingly uneconomic solutions to mitigate the impact of a large percentage of clean but uncontrollable generation in the system. At the same time, the question arise as to what extent Distributed Energy Resources (DER) could contribute to long-term generation adequacy, so as to postpone, for instance, conventional generation investment in the presence of load growth.

From a network standpoint, the spread of generation connected across the distribution network has substantial implications for power flow configurations and then again on the all network operation and development. In particular, as widely discussed in Deliverable DH1 [3], in a system where bulk of electricity supply comes from large scale transmission-connected generators, there are unidirectional power flows through transmission to distribution networks, and then on to end consumers via a series of voltage transformations. With penetration of small-scale generation even at low voltage (LV) level, these power flow patterns will change. Reverse flows may be expected as well, caused by uncontrolled generation connected to the distribution network producing more output than can be consumed by local demand. In some instances, these reverse flows may occur at the transmission-distribution boundaries resulting in export from the distribution network back to the transmission grid. In this respect, being sited in close proximity to demand, DG will reduce the distribution network import requirements, thus reducing the requirement for transmission capacity. While it is important to understand the magnitude of network capacity contribution from DG allowing decrease or postpone in transmission investment, similarly to generation adequacy, it is likely that a future low-carbon system will be constrained in its choice of generation location by availability of primary resources, so that transmission will still play a key role in long-distance bulk transportation of power from remote RES.

With specific regard to distribution networks where small-scale DG is being installed, for relatively small penetration levels mainly network benefits such as losses reduction and voltage support are likely to arise, which top up benefits such as emission reduction for instance due to utilization of distributed cogeneration close to the final heat users. Hence, having scattered DG popping up in the network as negative loads does not affect remarkably the network operation. However, with the main driver for benefits being correlation between demand and generation, with increasing share of uncontrolled and intermittent DG not correlated with demand the operating philosophy of the distribution networks needs to be changed. Indeed, with bi-directional power flows and increasing influx of generation into the network it will be more and more difficult for the distribution network operator to maintain a passive operation approach (DG equal to negative load) without investing heavily in network reinforcement [4] [5]. In this outlook, Active Management (AM) of the network will become a key approach to enable integration of local generation and higher network utilisation without resorting to network reinforcements, which could on the other hand hinder further integration of DER.

The Microgrids (MG) concept is to be framed within the context outlined above. More specifically, MG represent a form of LV networks (as well as medium voltage (MV) networks as aggregation of LV ones) where microgeneration and loads (and in general DER) can be controlled in order to reach predefined objectives. In particular, the scope of the analyses in Work Package (WP) H of the More Microgrids project, and particularly of this Deliverable, is to evaluate and quantify the potential contribution of MG in terms of network support and infrastructure development. In fact, while other aspects of MG are relatively better known (for instance, related to reliability improvements, for which the reader can find insights in WPG), the impact on electricity infrastructure evolution is to be thoroughly addressed yet. This report aims to cover this knowledge gap, and provides a number of quantitative analyses that follow up the introductory models illustrated in Deliverable DH1 which can inform policy makers and relevant stakeholders on the potential role of microgrids in system-wide impact and electrical infrastructure development. Among other issues, it is important to highlight how the need for this research is highly timely, considering that EU transmission and distribution networks were significantly expanded in the ‘60s and the assets then installed are approaching the end of their useful life and will need to be replaced. On the other hand, the need for coping with the climate chance challenges has brought an abrupt change in the generation philosophy, with the subsequent challenges to manage the system, as mentioned above.

This Deliverable summarizes the analyses carried out by several partners within Task TH2 of WPH. As such, it contains a substantial amount of work that, for the sake of readability, is organized in this main text accompanied by a number of Annexes with more details on specific studies (namely, on distribution networks and generation adequacy) that are summarized in the main part.
More specifically, the report is organized as follows:

- Chapter 2 describes the impact of Microgrids on distribution network replacement scenarios, based on the foreseen scenarios of DG and load evolution and different strategies. The studies are based on different approaches undertaken by the partners involved. In particular, northern and central European network scenarios have been analysed by Imperial on the basis of specific network data provided by partners, namely, FYROM, Germany, Netherlands, UK, and Poland. The analyses have been carried out by means of the Generic Distribution System (GDS) tool specifically developed to quantify the capacity of distribution network assets (as well as transmission assets) that can be displaced by Microgrids, as described in Deliverable DH1. In addition, while the GDS analyses mainly focus on CHP-dominated generation scenarios, southern European scenarios, with widespread use of PV, have been analysed by NTUA for Greece and by ERSE (former CESI Ricerca) for Italy. All the details of the studies are reported in Annex H2.A for GDS analyses and Annex H2.B for southern Europe analyses.
- Chapter 3 discusses the impact of Microgrids from a point of view of transmission investment. In particular, after discussing the general issues of the relation between

transmission investment and DG, the impact of DG controllability within MG is estimated through a UK case study, and relevant general considerations are carried out. A further case study example illustrates the utilisation of controllable loads within MG to increase the utilisation of transmission corridors and decrease the level of congestion, thus postponing the need for network reinforcements and decreasing the volume of intermittent renewable energy to be curtailed owing to capacity release.

- Chapter 4 contains studies carried out to analyse the impact and role of Microgrids relative to centralised conventional generation systems. More specifically, the concept of capacity credit, relative to generation adequacy and expansion planning, is discussed. Detailed probabilistic models, with illustrative studies relevant to a Portuguese case, have been elaborated by INESC[1] and are reported in Annex H2.C. In addition, the contribution of Microgrids to provide frequency response and reserve is assessed for different generation scenarios and levels of generation flexibility, pointing out the main drivers and providing quantitative indications about economic and environmental value that MG can bring in providing ancillary services to the system. This includes economic savings in terms of conventional generation expansion, and environmental savings owing to additional share of intermittent renewable sources (namely, wind) that can be economically and securely integrated in the system. Relevant analyses of the contribution to system services are carried out in terms of both controllable DG and controllable loads.
- Chapter 5 contains the concluding remarks on the work carried out within the Task.

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[1] INESC work on security of supply was originally scheduled for WPG but then it has been moved to WPH and is presented in this report based on its relevance to system development.

2. Impact of Microgrids on European distribution network development

This chapter illustrates a number of different analyses run to assess the impact of DG integrated within Microgrids on distribution network infrastructure development.
More specifically, a set of system-level impact studies has been run by Imperial College through the Generic Distribution System (GDS) model developed in this project. The model is capable to appraise the impact of DG and various Active Management (AM) strategies on the entire distribution network from a Grid Supply Point (GSP). Specific methodologies for static and dynamic replacement strategies have been developed, taking into account both investment and operational costs. Northern/Central networks and generation scenarios (dominated by CHP) have been used to populate the model based on data provided by project partners, to be representative of typical network configurations. In addition, specific Microgrids scenarios have been studied to identify the main drivers for impact and benefits in terms of infrastructure investment and replacement strategies. Relevant environmental analyses have also been carried out to crate a full picture of the costs and the benefits owing to Microgrids. The diversity of the networks and scenarios studied enables to get valuable insights on the potential impact of Microgrids for network replacement in Europe. Details on the Northern/Central scenario analyses are reported in Annex H2.A.
In addition to the GDS analyses, specific studies have been carried out for Southern networks and generation scenarios. More specifically, NTUA has run a case study to quantify the investment deferral benefits due to DG to a typical Microgrid test network, while ERSE has explored the benefits of PV-dominated Microgrids (in case operating autonomously) on MV network planning according to different design strategies. Details on the Southern scenario analyses are reported in Annex H2.B.
Further analyses by Imperial College have addressed greenfield distribution network replacement strategies to identify the value of DG and controllability for system development. Such analyses are based on a fractal model specifically developed for system-wide assessments. The same model has also been used to run a merge of network and environmental studies in CHP-dominated Microgrids, providing insights on the interaction between power systems and the heat sector, which is gaining increasing attention in the last years in order to develop more sustainable energy systems. Details on the fractal-based analyses are reported in Annex H2.C.

2.1 Generalities

Modern distribution systems were designed to accept power coming from the transmission system at the Bulk Supply Transformers of the Grid Supply Point (GSP) and to further distribute it to customers. Thus the flow of both real power (P) and reactive power (Q) was always from the higher to the lower voltage levels (Fig. 1).
However, as mentioned in the Introduction, with significant penetration of DG and Microgrids the power flows may become reversed, with 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 (Fig.2). The change in real and reactive power flows caused by Microgrids generation has important technical and economic implications for the power system [1].

The main reason is that DG is connected primarily within distribution networks, designed under the paradigm that consumer loads are passive and power flows only from substations to consumers and not in the opposite direction. In order to address this point, many studies on the interconnection of DG with distribution networks have been carried out, ranging from control and protection to voltage stability and power quality (for instance, [6][7][8], among many others). There have also been discussions about the environmental impact of widespread use of DG, in terms of pollutant emissions and noise. Notwithstanding the disadvantages of DG, important benefits have been acknowledged. These benefits are not only technical, such as the improvement of end-user power quality and reliability. In fact, there are a number of economic benefits of DG, the most important of which being the end-user electricity bill reduction, especially for gas-fired technologies (peaking internal combustion engines (ICEs) or microturbines (MTs)). This is especially valid in those regions where the so-called “spark spread”, that is, the difference between the local electricity rates and the gas prices, is high. The quantification of this benefit is relatively straightforward as the technology costs (upfront investment, taxes, utility rates, and fuel) can be weighed against annual expenditures in electricity purchases, and the financial returns can therefore be estimated without much effort by the end-user. On the other hand, utilities have recognized the importance of the utilization of DG solutions to defer the investment on distribution wires and power transformers. In some cases, DG has even been the only viable solution found to supply growing demands on certain neighborhoods, due to environmental opposition and aesthetical concerns.

This work then targets the quantification of one of the most important benefits of DG and Microgrids, which is the capability to defer planned or required investments in wires and transformers by distribution utilities. In fact, if the capacity deferral benefit of DG can be quantified, utilities can find new opportunities to implement “non-wires” solutions to tackle necessary network upgrades and internalize all benefits. Regulators have also more opportunities to better design credits for third-party owned DG investments that benefit not only the owner itself but the local utility altogether. Indeed, governments are devoted to provide the owners of renewable DG with credits of different sorts as a way of encouraging the installation of clean technologies. However, there has been some criticism regarding the way these credits are defined. We argue here that in an open market for DG deployment and incentives, such credits should be based on the real benefits produced by the particular DG solution and not in governmental policies in the form of flat production credits or tax benefits. The DG industry will only mature as a viable market alternative for consumers and utilities when all the benefits produced by a particular DG system are accounted for and credited to its owners.

In the sequel a number of analyses are run to identify the benefits and the costs that DG could bring about in terms of infrastructure development and expansion. The analyses will be mostly based on real scenarios provided by consortium partners. In addition, sensitivity studies will be carried out to examine the impact of a number of key factors on the overall benefits of microgrids, including micro generation technology, level of penetration, levels of integration of micro-generation within Microgrids (controllability level), seasonal operating patterns, correlation with demand, and so forth. As a major aspect within the Microgrids framework, we will highlight the potential additional benefits that controllability of DER and AM will be able to provide relative to a business-as-usual (BAU) case with DG but no microgrids. In fact, significant penetration of DG in distribution may create issues such as voltage rise effect in rural distribution and increased fault levels in urban distribution networks. Without proper management, they increase the cost of DG connection due to network reinforcement requirements, which ultimately influences the amount of additional DG that can penetrate the distribution system. Active management in Microgrids will thus enable maximization of the use of the existing circuits by taking full advantage of generator dispatch, control of transformer taps, voltage regulators, reactive power management, and system reconfiguration in an integrated manner. In order to have a full unbiased picture of positive and negative impacts, we'll run a full cost benefit analysis (CBA) aimed at identifying the cost optimal tradeoff between infrastructure replacement postponing and additional costs for instance due to need for supporting Information and Communication Technology (ICT) infrastructure.

2.2 Network investment strategies and value of active management within Microgrids based on Generic Distribution System (GDS) models

2.2.1 GDS model

The first tool developed for assessing microgrids and more in general DG impact on distribution networks is the so called **Generic Distribution System (GDS) model** [8]. Such tool allows the investigation of typical (generic) networks, with specified characteristics that change area by area and country by country, but that are still able to provide general results without going into detailed assessment of whole power systems. Indeed, the tool is simple enough yet capable to be used for accurate investigations involving a variety of operating conditions in order to capture the temporal and spatial impacts of DG on the network.

The input parameters of the networks analyzed are tuned to fit the distribution network characteristics for the specific countries, according to the data requested and provided by the partners (see Annexes of Deliverable DH1 [3] for the description of the template through which relevant data were requested). Then, the GDS model enables to run hourly load flow analyses (on an annual time frame and on the basis of typical seasonal characteristic days) on these distribution networks, and to provide relevant results on the impact of alternative microgrids penetration and operation scenarios (including different typologies of DG equipment involved) on losses, power flows, and voltage profiles. Thereby, sensible conclusions can be drawn on the need for network reinforcement rather than on the possibility of adopting **active management** schemes to increase the network performance and the penetration of DG. Such AM schemes range from coordinated voltage control policies to curtailment of distributed generation output, if necessary.

The complexity of modeling individual distribution networks can be mitigated with the development of a generic model, which enables us to represent typical European networks. The basic topology and design philosophy of distribution networks is common in most EU countries, with multi-voltage networks and substations with transformers between these networks. Regardless the variety of networks it is possible to encounter, all of them are characterized by a limited number of overhead line (OH) and underground (UG) cable typologies to convey power from the transmission system through the different voltage levels and eventually to end users. OH lines prevail for the higher voltage levels, whereas UG cables are more used in the lower voltage levels, above all in high-density urban areas. Transformers may vary in capacity and number per substation, whereas cables and lines may vary in capacity and length. Of course, the specific design in a specific area may affect resistance and reactance values (the main parameters for power flow assessment), but, to a large extent, for each country it is possible to draw generic networks that at first approximation resemble the typical ones from the various Distribution System Operators (DSOs) in that country. Such networks, in particular, are similar enough in topology and design philosophy so as to allow the adoption of a common modeling approach on a **Grid Supply Point (GSP)** basis (boundary between the meshed transmission and the radial distribution network), as described in [9] and [10].

The networks analysed in the GDS tool are operated **radially**, which is the typical approach in most countries. However, some networks might be operated in (weakly) meshed configuration. Meshed network modelling would require the implementation of advanced load flow calculations that go beyond the scope of the tool developed and might hinder the possibility of running general although simplified analyses. In addition, for strategic assessments (and not detailed design) of MG, as is the purpose of WPH, the difference in the impact on radial or weakly-meshed networks can be reasonably neglected. It is therefore assumed here that each distribution network is operated radially from the GSP point to the end users. Furthermore, it is assumed that the model is composed of well-balanced three-phase circuits and transformers. A graphical representation of a generic distribution network with various loads and distributed generators connected is shown in Figure 2.1.

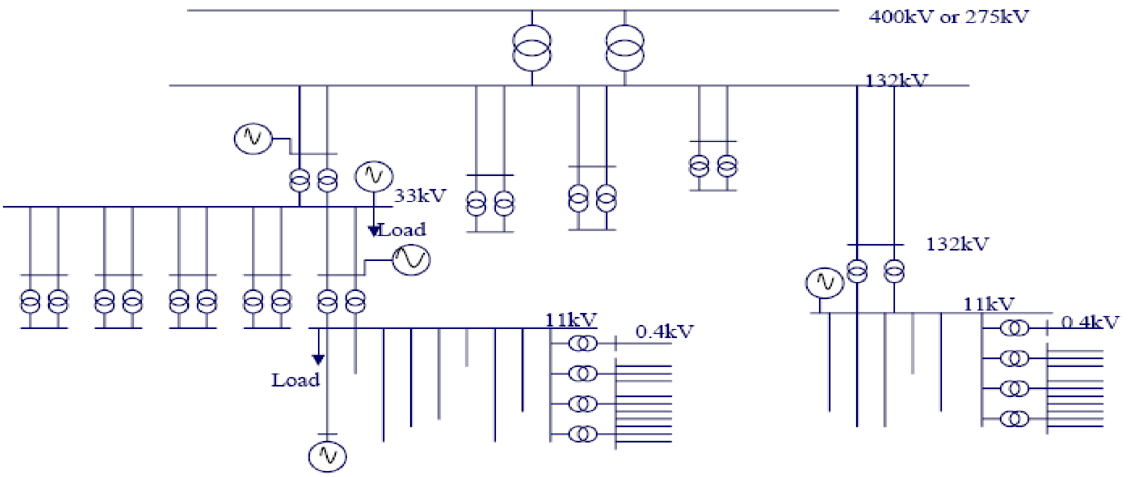


Figure 2.1. Representation of a generic distribution network.

Each voltage level in the GDS tool is modelled trough different **modules** [9]. A module is composed of a substation with the relevant transformers, the low voltage bus-bar of that substation, and a number of feeders (with loads and distributed generators connected to them) connected to that bus-bar, as depicted in Figure 2.2. Thus, when modelling a distribution network it is possible either to define as many modules as substations in the real network in order to obtain a totally precise but large model, or to define a smaller number of modules that would capture the key characteristics of the network. The latter approach is the most suitable for strategic analyses of large microgrid deployment in different countries. However, more accurate studies for targeted networks can be run in order to refine some specific details.

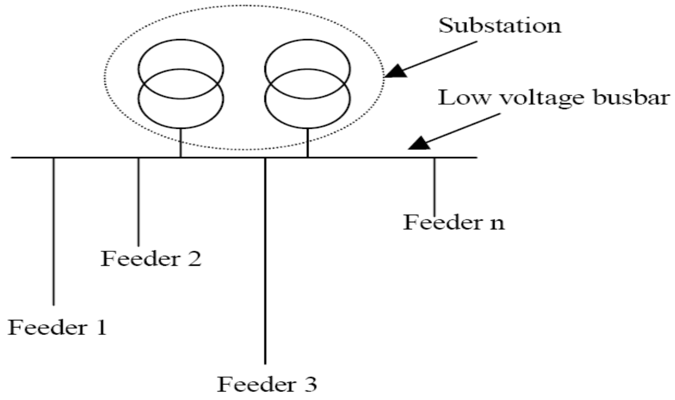


Figure 2.2. Representation of a GDS module.

The design of a module is flexible, as it is possible to choose the characteristics of the transformers (capacity, impedance, no-load losses at rated power and load losses at rated power, break rating of switchboards), the number of feeders connected to the bus-bar, their type (overhead line, cable or mixed), their length and size (and consequently their resistance, reactance and thermal capacity) -as well as different tapering configurations-, and the load/DG distribution among the different feeders and along each feeder. Apart from the technical parameters, the user can also choose the economic parameters of the network components (reinforcement price of feeders, transformers and switchboards). Finally, the structure of the connection between different voltage levels should be specified; the type and number of lower voltage modules allocated along each higher voltage feeder is defined by the user.

Owing to the differences existing between each voltage level, particularly with regard to the connection of load, DG and lower voltage substations to the feeders, the main configuration of the modules is typically slightly dissimilar for each voltage level.

Data on load and generation are organized according to typical hourly load profiles in nine characteristic days, representative of the overall year. Hence, hourly, daily (weekday, Saturdays and Sundays) and seasonal load and generation profile variations can be captured and used for load flow analyses that could cover the whole year time span. In addition, different load types (residential with and without electric heating, industrial, commercial and agricultural) and generation types (wind, PV, hydro, CHP, biomass, landfill gas, industrial waste) can be considered according to the specific country case. The distribution of loads and generators at each voltage level, among different modules of the same voltage level, among different feeders of the same module and along each feeder is also modeled [9]. Finally, the user can specify the power factor of the different loads and DG.

2.2.2 Active management modelling

Under the **Passive Management** regime, the distribution networks are designed to be able to operate with minimum real-time management and automatically deal with the worst-case expected situations. The adoption of this regime yields high investment on network components and a low network utilization, since these worst case situations occur very rarely. Under the -recently proposed- **Active Management** regime [11][12], instead of planning and operating the network in anticipation of worst case scenarios, the operator deals with constraints during different system conditions by exercising real-time management of voltage, power flows and fault level through a number of different components. In this work, we have focused on Voltage Active Management by utilizing reactive compensation, online tap changers and generation curtailment.

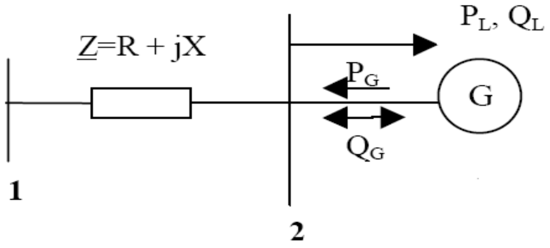


Figure 2.3. Illustration of voltage problems

The voltage at busbar 2 (V_2) of Figure 2.3 can be approximately calculated as follows:

$$V_2 = V_1 + (P_G - P_L)R + (\pm Q_G - Q_L)X \qquad (1)$$

Every DNO has an obligation to supply its customers at a voltage within specified limits (V_{2min} and V_{2max} which are country- and voltage level- specific parameters). If the values P_G, Q_G, P_L, Q_L for the generation and load are such that $V_2 < V_{2min}$ or $V_2 > V_{2max}$, a voltage drop or a voltage rise constraint arises. Under the Passive Management regime, the feeder will be replaced with one of smaller resistance R and reactance X (a feeder with larger cross section and capacity) in order to mitigate the voltage drop/rise between the two buses.

Under the Active Management regime, the high investment cost of reinforcing the feeder can be avoided by utilizing different control alternatives:

Voltage drop constraints:

Injecting reactive power at bus 2, by connecting a **capacitive reactive compensator** (e.g. a STATCOM) Q_{comp}, as depicted in Figure 2.4. The voltage at bus 2 will be increased at:

$$V_2 = V_1 + (P_G - P_L)R + (\pm Q_G - Q_L + Q_C)X \qquad (2)$$

It is important to observe from this equation that the effectiveness of this control action is greatly influenced by the value of line reactance X: reactive compensation is considerably more effective in overhead networks (with typical reactance of X_{OH}≈0.4Ω/km), than on cable networks (with typical reactance of X_C≈0.1Ω/km).

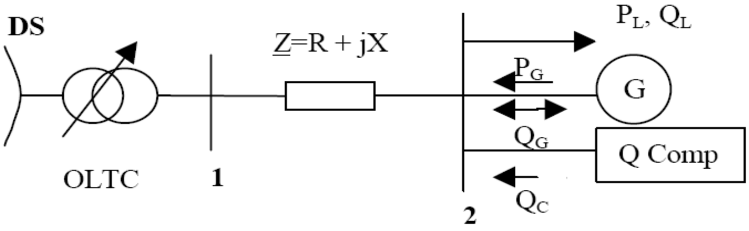


Figure 2.4. Active Management of voltage drop problems

Increasing voltage at bus 1 by changing the tap position of the **On Load Tap Changer (OLTC)** at the transformer, as depicted in Figure 2.4. However, a limit is imposed on this control alternative by adjacent feeders connected to the same substation, as it can be seen in Figure 2.5. Increasing V in order to increase V_1 (to mitigate a voltage drop constraint) will also increase the voltage at bus 2, as the following equation indicates:

$$V_2 = V - R_2 P_{L2} - X_2 Q_{L2} \qquad (3)$$

and a voltage rise problem will arise if $V_2 > V_{2max}$. This problem can be solved by implementing a **coordinated area-based control scheme** which takes into account the voltage at every feeder connected at the substation to keep V in a certain range in order to keep both V_1 and V_2 between the permissible limits ([11] and [12]).

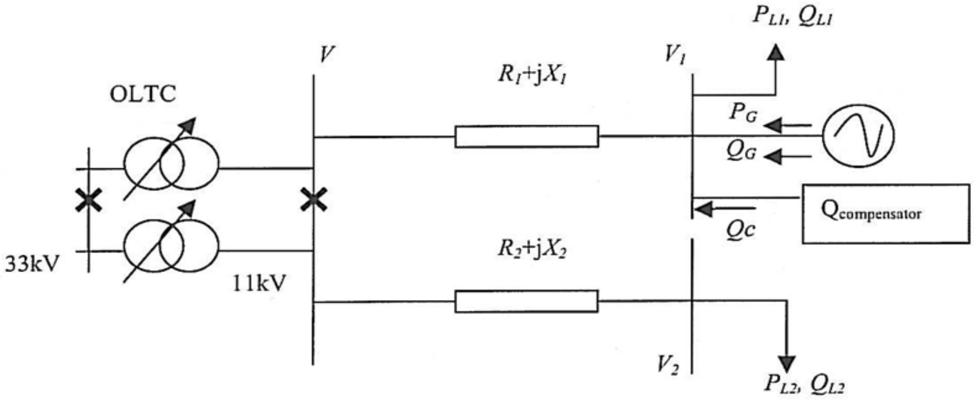


Figure 2.5. Limitations imposed on the action of OLTC by adjacent feeders

Voltage rise constraints:

Absorbing reactive power from bus 2, by connecting an **inductive reactive compensator** Q_{comp}, as depicted in Figure 2.6. The voltage at bus 2 will be decreased at:

$$V_2 = V_1 + (P_G - P_L)R + (\pm Q_G - Q_L - Q_C)X \qquad (4)$$

The same observation regarding the impact of the line reactance on the effectiveness of this control action stands here.

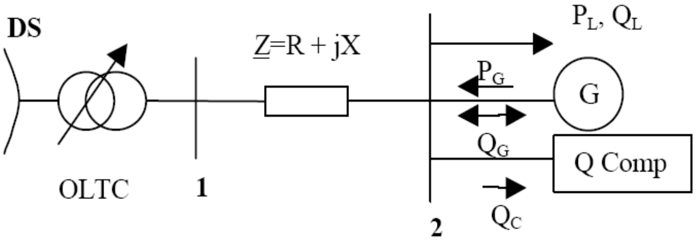


Figure 2.6. Active Management of voltage rise problems

Decreasing voltage at bus 1 by changing the tap position of the **On Load Tap Changer (OLTC)** at the transformer (Figure 2.6) and implementing a coordinated area-based control scheme as mentioned before.

Curtailing active power generation (decreasing PG). The probability of the coincidence of low load and high generation will determine the total energy curtailed. As the price of electricity is primarily driven by load demand and voltage rise problems occur typically during periods of low demand, the value of the curtailed energy is likely to be relatively low [12].

Another possible means of voltage management could be the control of the reactive power generation Q_G (control of the generator's power factor) of the units operating in the Microgrid. However, this option is not included in the model, and a single value for the power factor of each DG was specified at the data received from our European partners. Thus, the only modification in Q_G occurs when active power generation curtailment takes place and the power factor of the generator is not equal to one. Nevertheless, it has to be considered that in practice reactive support could be provided by distributed generators connected at LV in the Microgrids. This is particularly relevant when voltage drop issues due to large loads occur. In this case, the model developed calculates reactive compensation needed at the end of the feeders where voltage drop problems arise. This reactive compensation could in case be provided by changing the DG power factor of the units operating in the Microgrid, with subsequent benefits mainly at voltage levels higher that LV (the weight of reactance at LV is negligible, so that reactive flows do not support voltage profiles substantially, differently from MV where the weight of reactance is relatively higher).

2.2.3 Cost of Active Management implementation

In this section, the cost incurred by the distribution network operator (DNO) for the implementation of each control option is presented. This data is the result of a survey that was carried with 3 DNOs in the UK and is presented in detail in [12]. Since similar data for other countries was not available, these values were used for the calculation of the implementation cost of active management in the networks of every country (the exchange rate used was 1£=1.11€).

Reactive power compensation: The cost of this control option can be divided into two components:

1a) The **capacity cost** of the compensator, which is £30,000 per MVar. We have assumed that this cost is infinitely modular, meaning that when the capacity of an already installed compensator needs to be increased, the capacity cost incurred is given by the extra capacity needed times the above mentioned value per MVar.

1b) The **fixed cost** of implementing this option (Figure 2.7), which includes the cost of: a *voltage transformer* (£1000) which transforms the high network voltage to smaller values, suitable for measurement and control purposes, a *transducer* (£200) which converts the output of the voltage transformer to a voltage measurement suitable for communication with the network operator, a *Supervisory Control And Data Acquisition (SCADA)* system which processes the voltage measurements and the instructions it receives from the network operator and controls the operation of the compensator according to these instructions and a *Remote Telemetry Unit (RTU)* which constitutes the interface between the control and measurement system at the reactive compensator and the chosen communication circuit, used for sending field measurements to and receiving instructions from the network operator (total cost of the SCADA and the RTU is £2500 – it is assumed that power line communication is used, so no additional cost for the communication is incurred by the network operator). According to the previous values, the total fixed cost is £3700 (per compensator).

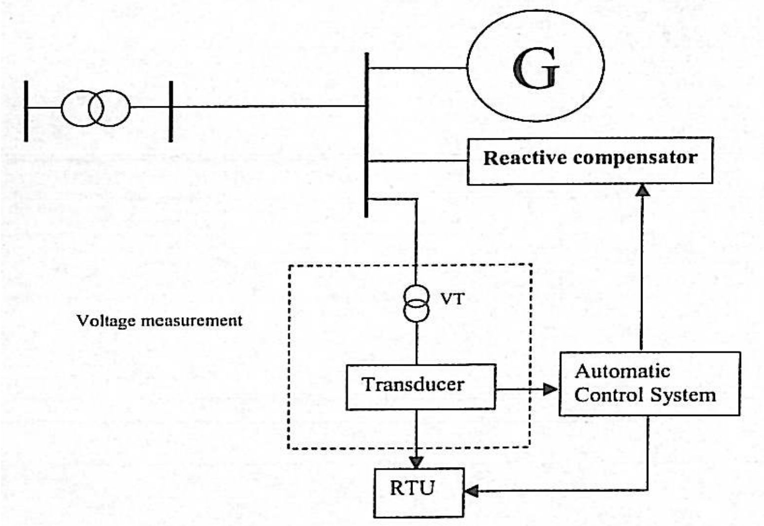


Figure 2.7. Control and measurement system for reactive power compensation

Generation Curtailment: The cost of this control option is divided into two components as well:

2a) The **cost of the curtailed energy** in the electricity market, which is equal to the price of energy (country- and voltage level- specific, given in £/MWh or €/MWh) times the curtailed energy in MWh

2b) The **fixed cost** of implementing this option (Figure 2.8), which is equal to the respective cost of the reactive power compensation option (£3700 per DG)

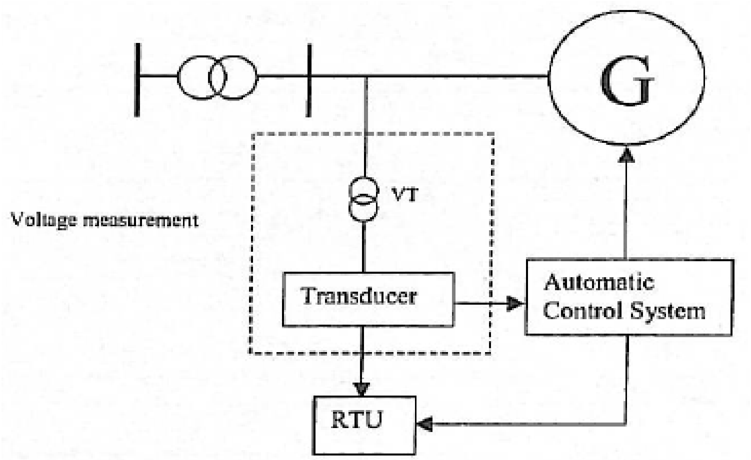


Figure 2.8. Control and measurement system for generation curtailment

Coordinated area-based control with On-Load Tap Changers: There is only a **fixed cost** component for the implementation of this control option (Figure 2.9 and Figure 2.10). *Two on load tap-changer relays* are needed per substation (£1750 each) and they are controlled with an *automatic voltage control (AVC) relay* (£1250) which receives instructions from the SCADA. A *voltage transformer* (£1000) is connected at the lower voltage side of the substation for transforming the high network voltage to smaller values, suitable for measurement and control purposes (a transducer is not needed at this point since the conversion of the output of the voltage transformer to a voltage measurement suitable for communication with the network operator is carried out by the AVC relay). As we mentioned in the previous section, the voltage at every feeder connected to the substation (and not only at the feeders with voltage problems) must be taken into account and consequently a voltage measurement is needed at each feeder. Therefore, at each of these feeders, a *voltage transformer* (£1000), a *transducer* (£200) and an *RTU* is installed (Figure 2.10). All the voltages measured are sent to the network operator, who calculates the optimal tap setting and instructs accordingly the *SCADA* (£2700 including the cost of all the RTUs installed). According to the previous values, the total cost of this control option is £8450 for the control and measurement system at the substation and £1200 for the voltage measurement system at each feeder.

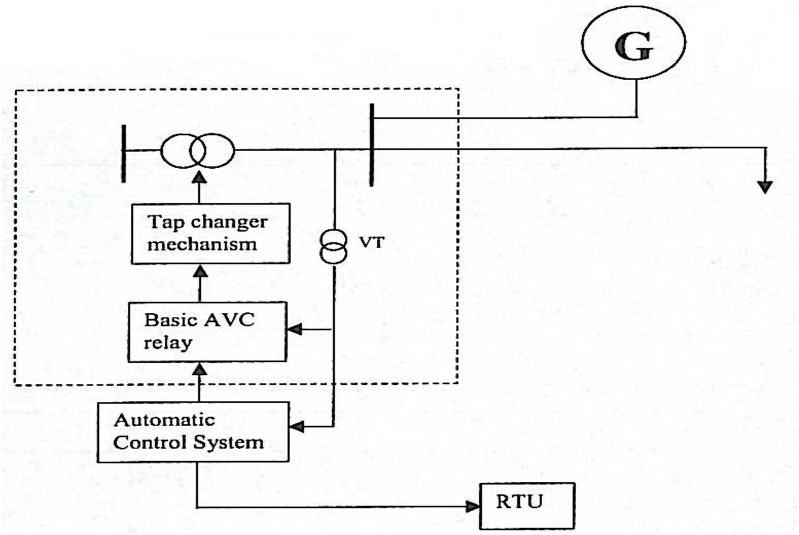


Figure 2.9. Control and measurement system at the substation

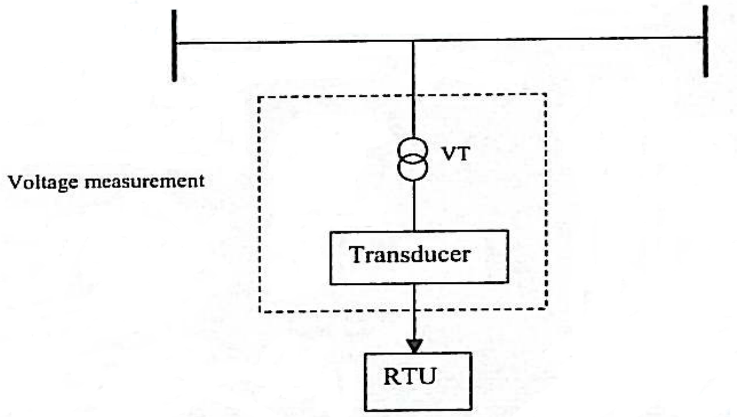


Figure 2.10. Measurement system at each feeder

2.2.4 Optimisation of Active Management controls

An optimisation method is required in order to determine the least-cost combination of the above control options resolving the voltage problems arising in the distribution network. Since the control with OLTC has only a fixed cost component (installing tap changers is a discrete decision), two alternative active management strategies were considered:

Active management without tap changers. A capacitive compensator with the relevant control and measurement system presented above is connected to each feeder facing a voltage drop problem; on the other hand, an inductive compensator with the relevant control and measurement system is connected to each feeder with a voltage rise problem and the relevant control and measurement system enabling generation curtailment is connected to each generator (if any) on this feeder. An optimisation algorithm embedded in the GDS model determines the least-cost combination of generation curtailment (GC) and reactive compensation (RC) resolving each voltage problem in the network. Since the fixed cost of these two control options is the same, only the annual cost of the curtailed energy in the electricity market (CCE_A) and the annualised capacity cost of the compensator (CCC_A) are included in the objective function:

$$MIN_{GC,RC}(CCE_A + CCC_A) \tag{5}$$

Active management with tap changers. The relevant control and measurement system presented in Figure 2.9 is connected to each substation where at least one feeder with a voltage problem is connected and the measurement system presented in Figure 2.10 is connected to each feeder connected to this substation. The tap changers alone might not be able to resolve the problems arising due to the following limitations: i) the minimum and maximum limits imposed on the tap position (country- and voltage- level specific parameters) ii) the need to keep the voltage at every feeder connected to the substation within the permissible limits (as explained in Section 2.2.2 and illustrated on Figure 2.5). If this is the case, reactive compensation and generation curtailment is deployed as explained in strategy a). The objective function of the optimization algorithm is the same as in strategy a), but apart from the generation curtailment and the reactive compensation, the tap position of the tap changers (T) is optimised:

$$MIN_{GC,RC,T}(CCE_A + CCC_A) \tag{6}$$

The implementation cost of strategy a) is highly proportional to the number of feeders suffering from voltage problems and the severity of these problems (deviation from the acceptable voltage limits) while the implementation cost of strategy b) is much less affected by a change in these parameters (once tap changers are installed in a substation, they can deal with voltage problems in every feeder connected to the substation and irrespectively of their severity if the above mentioned limitations are not reached). Therefore, the relation between the cost of strategies a) and b) depends on the nature of the voltage problems in the network. In a network with a small number of feeders suffering from voltage problems and moderate violations of the voltage limits (small deviation from the minimum or maximum voltage limit), the cost of the required compensation and generation curtailment under strategy a) is lower than the fixed cost of installing tap changers and strategy a) is more economic. In a network with a large number of feeders suffering from voltage problems and severe violations of the voltage limits (big deviation from the minimum or maximum voltage limit), the cost of the required compensation and generation curtailment under strategy a) becomes very high and strategy b) becomes more economic.

2.2.5 Outputs of analysis with the GDS model

Each GDS simulation runs on an annual time frame and provides us with certain technical results regarding the examined distribution network:

-Total annual losses (in MWh), annual losses per voltage level and annual losses per network component (losses on transformers – losses on feeders)

-Total energy production per type of DG (in MWh)

-Maximum power flow on each network component and consequently determination of thermal problems in the network

-Maximum voltage drop/rise on each feeder and consequently determination of voltage problems in the network

-Contribution from each DG at the fault level of the terminal busbar they are connected to and consequently determination of fault level problems in the network

-Energy curtailment of each generator (in MWh) and capacity of reactive compensation installed at each feeder facing voltage problems (in MVar) when Active Management is deployed

By processing these results with suitable models, we were able to assess the technical, economic and environmental benefits of Microgrids (Distributed Generation and Active Management), as presented in the next subsections.

2.2.6 Benefits related to losses

For each scenario analysed, the **losses reduction** by the installation of DG is calculated as:

$$LR(\%) = \frac{L_{WODG} - L_{WDG}}{L_{WODG}} \quad (7)$$

(where L_{WODG} the annual energy losses without DG connected at the network and L_{WDG} the annual energy losses with DG connected at the network). This reduction is calculated for the total losses in the network, the losses at each voltage level and the losses at each type of network component (feeders-transformers), and for the different operating strategies (passive management, active management without tap changers and active management with tap changers).

The **annual cost of losses** can be calculated by the product of the losses L and the price of energy p (country-specific parameter) at each voltage level VL (N is the number of voltage levels in the network):

$$CL = \sum_{VL=1}^{N}(L_{VL} * p_{VL}) \tag{8}$$

Therefore, for each scenario analysed and each of the operating strategies, the **cost of losses reduction** by the installation of DG is calculated as:

$$\Delta CL = CL_{WODG} - CL_{WDG} \tag{9}$$

(where CL_{WODG} the cost of losses without DG connected at the network and CL_{WDG} the cost of losses with DG connected at the network)

The reduction of losses by the installation of DG results in **CO_2 emissions reduction** calculated as:

$$\Delta CO_2(losses) = (L_{WODG} - L_{WDG}) * \mu_{mp} \tag{10}$$

(where μ_{mp} the emission factor of the marginal plant of central generation). This model was followed since we have assumed that losses in the distribution network are covered from the central generation and more specifically by the last plant in the unit commitment list. Since the development of a model which would estimate the changes in unit commitment and economic dispatch of the central generation due to the connection of DG (and would enable us to identify the marginal plant every hour) is out of the scope of this work, we have carried out a parametric analysis for the emissions reduction, using different values for μ_{mp}.

2.2.7 Benefits related to reinforcement

Based on the technical results from the GDS simulation, we can calculate the **reinforcement cost** required for resolving the various problems arising, under passive and active management. We need to stress that: i) only reinforcement costs (and not expansion costs) were taken into account and ii) the reinforcement strategy we used took into account the indivisibility of assets (a certain number of standard types and sizes of feeders, transformers and switchboards are available in each country) and the reinforcement policy defined by the DNO of each network we have analysed (e.g. in Germany, the type and size of feeders that will be used when reinforcement of underground cables is needed is defined in the data we received from our partners).

Passive management: feeders are reinforced when they face a thermal (maximum power flow on them is greater than their thermal capacity) or voltage problem (maximum voltage drop/rise on them is greater than the voltage drop/rise limit imposed on the DNO; this limit is country- and voltage level- specific), transformers are reinforced when they face a thermal problem (maximum power flow on them is greater than their thermal capacity) and switchboards at substations are reinforced when they face a fault level problem (the fault level contribution of DGs connected to these substations is higher than the available break rating headroom of the switch board; a parametric analysis was carried out using a 10%,20% and 30% headroom). Consequently, the total reinforcement cost is

$$TRC_{PM} = RCF_T + RCF_V + RCT + RCS \tag{11}$$

where RCF_T the cost of reinforcing feeders with thermal problems, RCF_V the cost of reinforcing feeders with voltage problems, RCT the cost of reinforcing transformers and RCS the cost of reinforcing switchboards.

Active management: as under passive management, feeders and transformers are reinforced when they face a thermal problem and switchboards are reinforced when they face a fault level problem. Voltage problems of feeders are resolved by the deployment of generation curtailment, reactive compensation and coordinated control of tap changers, according to the active management strategy followed (with or without tap changers). The deployment of each of these controls has specific cost components (presented above). Consequently, the total reinforcement cost is:

$$TRC_{AMwithout} = RCF_T + RCT + RCS + CGC + CRC \tag{12}$$

$$TRC_{AMwith} = RCF_T + RCT + RCS + CGC + CRC + CTC \tag{13}$$

where CGC,CRC,CTC the cost of deploying generation curtailment, reactive compensation and coordinated control with tap changers respectively.

For each scenario analysed and each of the operating strategies, the **reinforcement cost reduction** by the installation of DG is calculated as:

$$\Delta RC = RC_{WODG} - RC_{WDG} \tag{14}$$

(where RC_{WODG} the reinforcement cost without DG connected at the network and RC_{WDG} the reinforcement cost with DG connected at the network). This reduction is calculated for the total reinforcement cost, the reinforcement cost of each voltage level and the reinforcement cost of each type of network component (feeders-transformers).

2.2.8 Benefits related to total network cost

In order to evaluate the **total network cost** for each examined scenario and each operating strategy, it is necessary to transfer the two components of this cost (reinforcement cost and cost of losses) to a common temporal basis. The models followed to achieve this depend on the scope and the inputs of the analysis carried out and consequently will be presented in Section 2.2.10. After this step, we will be able to calculate the **total network cost reduction** by the installation of DG as:

$$\Delta NC = NC_{WODG} - NC_{WDG} \qquad (15)$$

where NC_{WODG} the network cost without DG connected at the network and NC_{WDG} the network cost with DG connected at the network.

2.2.9 Benefits related to local power generation

Generation at the distribution level contributes to supply demand that should otherwise be supplied by central generation; hence, the equivalent residual demand as seen at the GSP from the transmission network is reduced [3]. This reduction can be expressed by the reduction in the maximum power (in MVA) flowing on the boundary between the examined distribution network and the upward transmission network (transformers of the highest voltage level of the examined distribution network), which has a beneficial impact on **transmission investment decisions**. Moreover, the installation of DG modifies the shape of the aggregate demand curve of the distribution network (profile of the power flowing on the boundary), which has an impact on **central generation scheduling decisions**. We need to stress that the development of models quantifying these two impacts is out of the scope of this work.

Since local energy production displaces part of the central one and is characterized by much lower (or even zero in cases of renewable generators) CO_2 emissions, the installation of DG results in **CO_2 emissions reduction**. The calculation of this reduction is based on the marginal plant model presented in Section 2.2.6 and is different for different types of DG [3]:

Renewable Generators: these generators do not produce CO_2; thus the annual reduction in CO2 due to renewable generation is

$$\Delta CO_2(RES) = W_{RES} * \mu_{mp} \qquad (16)$$

where W_{RES} is the annual renewable energy production and μ_{mp} is the emission factor of the marginal plant of central generation

Combined Heat and Power Generators: the emissions reduction from the operation of these generators is not only due to the displacement of central electricity production but also due to the displacement of useful heat produced by conventional boilers; thus it is calculated as:

$$\Delta CO_2(CHP) = W_{CHP}\left(\mu_{mp} - \mu_W\right) + Q_{CHP} * \mu_Q \qquad (17)$$

with

$$Q_{CHP} = W_{CHP}\frac{n_Q}{n_W} \quad \text{and} \quad \mu_W = \frac{\mu_F}{n_W}$$

where W_{CHP} and Q_{CHP} the annual electricity and heat production of the CHP respectively, n_W and n_Q the electrical and thermal efficiency of the CHP (the values used in our analysis for different CHP sizes/technologies are given in Table 2.1), μ_F the emission factor of the fuel used by the CHP (natural gas with 200g/kWh was considered in our analysis) and μ_Q the emission factor of the standalone boiler (assumed 240g/kWh in our analysis) displaced by the CHP.

Table 2.1. Electrical and thermal efficiency for different CHP sizes

	Micro CHP	**Small CHP**	**Medium CHP**	**Large CHP**
η_W	0.2	0.3	0.35	0.4
η_Q	0.7	0.55	0.5	0.45

2.2.10 Scenarios and types of analysis examined

Our analysis on the technical, economic and environmental benefits of Microgrids is divided into two parts: i) dynamic assessment of the impacts of Distributed Generation and Active Management on European distribution systems over different network scenarios based on the foreseen DG and demand evolution as provided from our partners and ii) parametric assessment of the impacts of micro DG and AM on today's European distribution networks.

Dynamic assessment of DG and AM based on partners' scenarios

Our partners from Northern and Central European countries have provided us with the expected demand and installed DG capacity on typical distribution networks of their countries in four future yearly snapshots. Our task in this part of the analysis was to assess the benefits of DG and AM on these networks in a **dynamic fashion**.

Since the data concerning the DG penetration evolution were given for these 4 snapshots t0, t1, t2 and t3, we have assumed that connection of new DG and network reinforcement will only take place in these snapshots (and consequently we have run GDS simulations only for these snapshots), in order to simplify the analysis (a year by year assessment would need extremely more GDS simulations and would require a number of uncertain assumptions about the DG penetration evolution in intermediate years).

In each snapshot, we run GDS simulations for two cases: i) **base case**, where no DG is connected at the network and the network problems arising are solved by deploying passive management and ii) **test case**, where the foreseen for this snapshot DG is connected at the network and all the possible reinforcement strategies (passive management, active management without tap changers, active management with tap changers) are examined and compared, based on their network cost (reinforcement cost and cost of losses).

As we stressed in Section 2.2.8, in order to evaluate the total network cost for each of the above cases, we need to bring its two components in the **same temporal basis**. Since network reinforcement takes place in specific snapshots, the time window between two consecutive snapshots can constitute this common basis. Since the economic parameters of the assets (inputs of the analysis) correspond to the current value of their total capital cost, the reinforcement cost calculated in the first place (RC) refers to a temporal basis equal to the life cycle of the distribution assets (assumed 20 years in this work); it can be brought to the common basis by subtracting the (present value of the) **residual (or salvage) value** of the assets at the end of the time window. For example (Figure 2.11), the cost of reinforcing the network in the time window t0 to t1 is equal to the present value of the reinforcement cost incurred in t0 minus the present value of the residual value of this investment in t1. We have assumed that the residual value of the assets depends only on the number of years they have been used, in a linear fashion. Thus, in the same example, the residual value of the investment will be: $RV = (1 - \frac{t1-t0}{20})RC$ $RV = \frac{15}{20}RC$, since the life cycle of the assets is 20 years and the length of the examined time window is t1-t0 years. Moreover, we have assumed that the cost of assets increases with the **annual inflation rate** (g=3% for every country in this work).

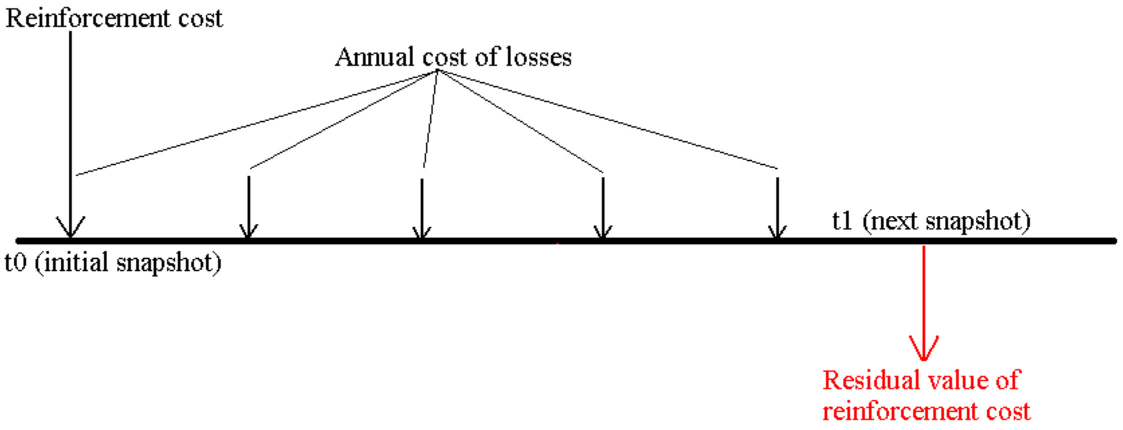


Figure 2.11. Model for the calculation of total network cost

On the other hand, the cost of losses for each case is brought to this common basis by calculating the present value of the annual cost of losses for each of the years of the examined time window. For example (Figure 2.11), the cost of losses in the time window t0 to t1 is equal to the sum of the present value of the cost of losses in t0 and each of the intermediate years between t0 and t1. Since the GDS simulation with the t0 demand and DG data gives us the annual losses for t0, we have used an **interpolation method** in order to project the losses in each of the subsequent years, by taking into account the annual increase rate of the load (provided by our partners). Moreover, we have assumed that the price of energy at each voltage level (which is used in order to calculate the cost of losses) increases with the annual inflation rate.

Hence, the total network cost in the time window t0 to t1 in the above example will be:

$$NC_{2010-2015} = RC_{PV} - RV_{PV} + \sum_{2010}^{2014} CL_{PV} \qquad NC_{t0-t1} = RC_{PV} - RV_{PV} + \sum CL_{PV}$$
(18)

where RC_{PV} the present value of the reinforcement cost incurred in t0, RV_{PV} the present value of the residual value of this reinforcement in t1 and $\sum CL_{PV} \sum_{2010}^{2014} CL_{PV}$ the sum of the present value of the cost of losses in each of the years included in this time window.

In the test case (case with DG), the reinforcement strategy which gives the lowest total network cost in the next time window is the one that will be selected; in the previous example, the strategy which gives the lowest network cost for the time window t0 to t1 will be selected for the reinforcement of the network in t0 (**optimal reinforcement strategy** in t0). This decision will affect the future structure of the network since this optimally reinforced network will constitute the input network for the GDS simulation for t1 etc, as depicted in Figure 2.12. By following this model, we are able to assess the

dynamic impacts of DG and AM on distribution network evolution, like cases of **reinforcement deferral**.

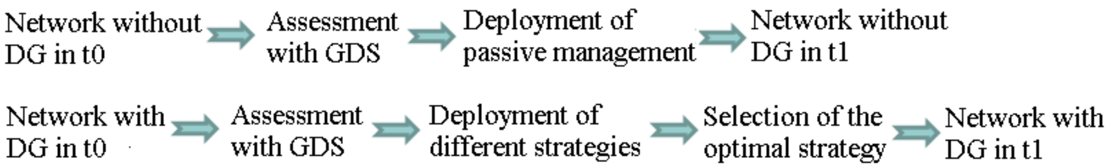


Figure 2.12. Dynamic network assessment model

Parametric assessment of micro DG and AM on current networks

In this part of the work, our task was to assess the benefits of micro DG (DG at the Low Voltage level) and AM on typical distribution networks (in their current form – no dynamic assessment was investigated in this case) of 5 countries (UK, Germany, Netherlands, Poland and FYROM). In order to do that, we have carried out a **parametric analysis** investigating 3 scenarios for the micro DG penetration (50%, 100%, 150% of current load at LV) and two scenarios for the load at LV (110% and 150% of current load at LV). In the rest of the voltage levels, the load was considered fixed and equal to its current value and no DG was connected. Only Combined Heat and Power (CHP) generators and Photovoltaic (PV) panels were considered as micro Distributed Generators (since these are currently the most mature technologies for connection at LV), with country-specific shares presented in Table 2.2:

Table 2.2. CHP and PV shares in the micro DG scenarios.

	UK	Germany	Netherlands	Poland	FYROM
CHP	95%	60%	60%	60%	20%
PV	5%	40%	40%	40%	80%

The above-mentioned scenarios refer to a single snapshot (current year) and consequently the model used in this part of the analysis is much simpler than the dynamic model presented in the previous section. The common temporal basis for the evaluation of the total network cost of each DG penetration and each reinforcement strategy was simply the year which the simulation refers to. The reinforcement cost can be brought to this common basis by annualising it:

$$ARC = RC * \frac{d*(1+d)^N}{(1+d)^N-1} \qquad (19)$$

where d the discount rate (assumed 7% in our analysis) and N the recovery period of the capital investment needed (assumed 20 years in our analysis). Hence, the total network cost for the examined snapshot will be:

$$NC = ARC + ACL \tag{20}$$

where ACL the annual cost of losses. Based on this network cost, the **optimal reinforcement strategy** and the **optimal DG capacity** for each load scenario can be identified.

2.3 Northern and central European scenario analyses: Poland

2.3.1 Dynamic assessment of DG and AM based on partners' scenarios

Our dynamic analysis on the Polish distribution network shows that the large majority of the required **reinforcement** in each of the examined time windows is related to **violations of voltage limits** caused by demand (voltage drop), with the most severe problems arising at the **medium voltage level**, since it is characterized by many long, overhead lines. Reinforcement driven by the installation of DG is only encountered in 2010, when some large wind turbines are connected to weak 15kV feeders; in the rest of the examined time windows, since the problems arising are caused by demand, DG reduces reinforcement cost, by mitigating these problems. The dynamic nature of our analysis enables us to witness not only **reinforcement cost reduction**, but also **reinforcement deferral by the installation of DG**: in the base case (no DG), the 110kV transformers need reinforcement in 2020 while in the test case (with DG), they need reinforcement in 2030.

The deployment of **active management reduces further the reinforcement cost** in each time window, since the cost of implementing the active controls is much lower than the cost of replacing the feeders suffering from voltage problems. The active management strategy giving the lowest reinforcement cost in each of the examined time windows is **AM without tap changers**. Active management in the time window 2010-2015 includes **curtailment** of the production of the generators causing voltage rise problems; however, the total curtailed energy of each involved generator is less than 2% of its total energy production during this time window. The dynamic nature of our analysis enables us to witness not only reinforcement cost reduction, but also **reinforcement deferral by the deployment of active management**: in the base case the replacement of certain heavy-loaded feeders is needed in 2010 because they face voltage problems; in the test case this replacement in 2010 is avoided (since active controls are used in order to resolve these problems) and it is deferred in 2015 when the same feeders face thermal problems (that is why in the test case, there is an increase in the reinforcement cost related to feeders' thermal problems in the time window 2015-2020, as shown on Figure 2.13).

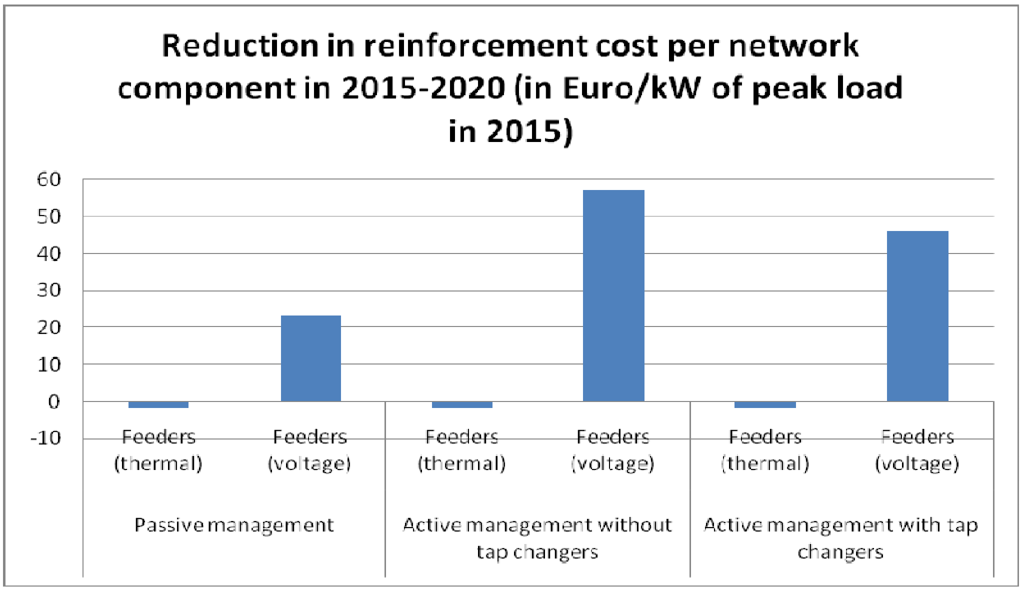


Figure 2.13. Reinforcement deferral by the deployment of active management

As depicted on Figure 2.14, **losses under passive management are lower** because the feeders suffering from voltage problems are replaced with feeders of smaller resistance (which is not the case under active management); moreover, **active management without tap changers is characterized by higher losses** than active management with tap changers: when only capacitive compensation is used for resolving the severe voltage drop problems arising at 15kV feeders, its required capacity is high enough to create significant **reverse power flows** at these feeders. Since active management without tap changers is deployed in each of the examined yearly snapshots (because it gives the lowest total network cost in each of the examined time windows) in the test case, the network in this case carries such a significant amount of capacitive compensation and feeders of large resistance when we move from one examined snapshot to another and thus its **losses (and their cost) throughout the years are higher than in the base case**, despite the fact that DG reduces the power flows on the distribution network.

Figure 2.14. Losses reduction in 2015 under different strategies

Even though the cost of losses is generally higher in the DG case than in the base case, the reinforcement cost is much lower in the former and thus **DG brings a benefit** with regard to the **total network cost. Active management reduces further the total network cost**, because its positive impact on the reinforcement cost is much more significant than its negative impact on the (cost of) losses; more specifically, **active management without tap changers** is the optimal strategy in each of the examined time windows (Figure 2.15).

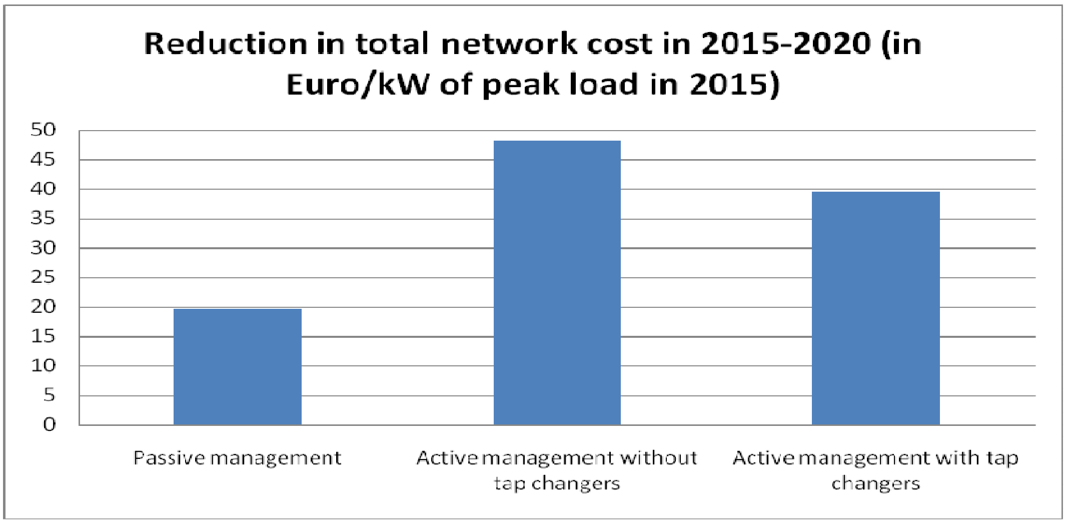


Figure 2.15. Reduction in total network cost in 2015-2020 under different strategies

2.3.2 Parametric assessment of micro DG and AM on current networks

Our snapshot-based analysis on the Polish distribution network shows that the whole required **reinforcement** in both low and high load scenarios is related to **voltage drop problems** and -as in the previous part of the analysis- the installation of micro DG and the deployment of active management reduce reinforcement cost. Our parametric analysis has demonstrated that **as the micro DG penetration increases, the reinforcement cost is reduced**; moreover the **benefits of active management** (in comparison with passive management) **become less apparent when the micro DG penetration increases and the demand decreases**, as the emerging voltage drop problems become less severe (Figure 2.16). The active management strategy giving the lowest reinforcement cost on each micro DG penetration-demand scenario depends on the relative severity of the emerging voltage problems.

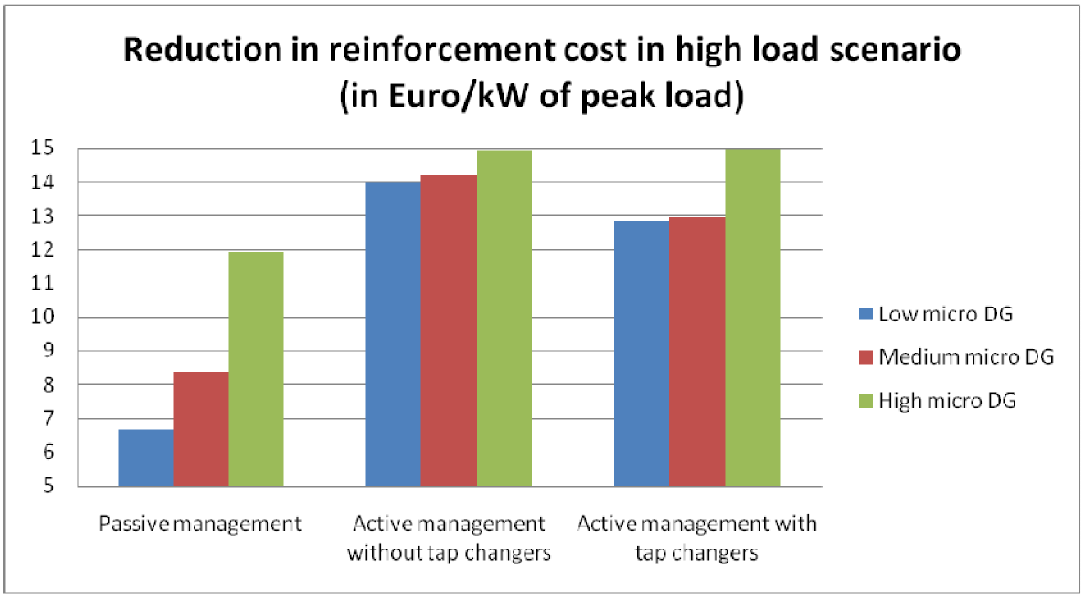


Figure 2.16. Parametric analysis of the reduction in reinforcement cost

As the micro DG penetration increases, the losses reduction with respect to the base case becomes more significant, as larger part of the power required by the load is supplied locally, and thus the power flows on the network are reduced. The two differences in losses between the different strategies (described in Section 2.3.1) become less apparent as micro DG penetration is increased and load is decreased, since less voltage drop problems occur and thus fewer feeders are replaced under passive management and less capacitive compensation is connected at the suffering feeders under active management without tap changers (Figure 2.17).

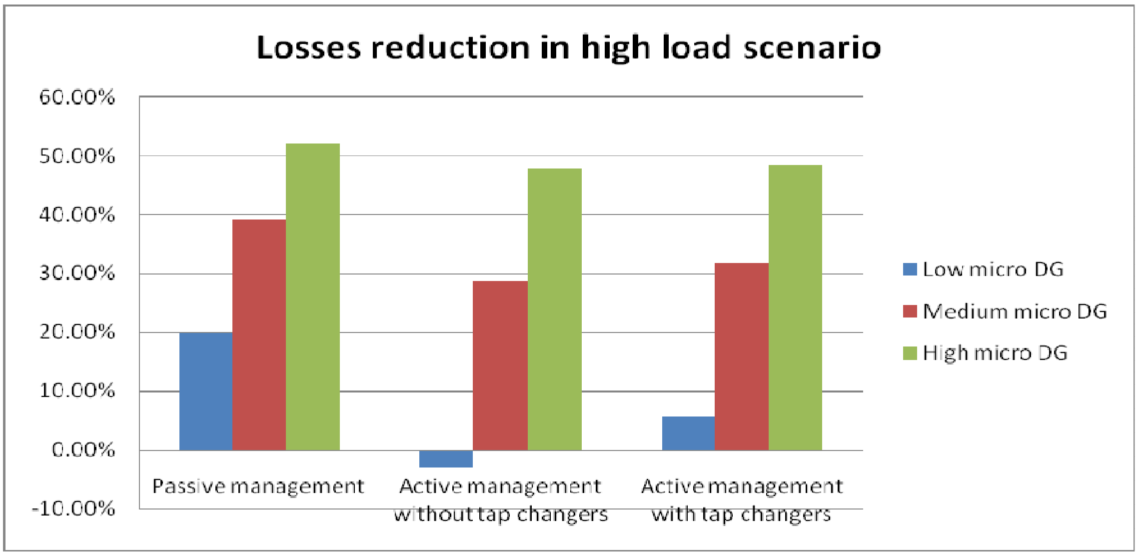


Figure 2.17. Parametric analysis of the reduction in losses

As the micro DG penetration increases the total network cost is reduced, since this trend is observed in both reinforcement cost and cost of losses and the active management strategy giving the lowest total network cost on each micro DG penetration-demand scenario depends on the relative severity of the emerging voltage problems.

2.4 Northern and central European scenario analyses: FYROM

2.4.1 Parametric assessment of micro DG and AM on current networks

Our analysis on the FYROM distribution network shows that **very significant reinforcement** is required in both low and high load scenarios, related to **violations of both voltage and thermal limits** (almost equally significant) caused by demand, with the most severe problems arising at the **very weak low voltage level**. Since this reinforcement is driven by demand, **as the micro DG penetration increases, the reinforcement cost is reduced**; evidence of the weakness of the network is the fact that a low micro DG penetration cannot extenuate at all the arising problems in the low load scenario under passive management (Figure 2.18).

The deployment of **active management reduces further the reinforcement cost** (since the cost of implementing the active controls is much lower than the cost of replacing the feeders suffering from voltage problems) but this benefit **becomes less apparent when the micro DG penetration increases and the demand decreases**, as the emerging voltage drop problems become less severe. Active management with tap changers gives the least reinforcement cost in scenarios where the severity of the voltage problems is relatively high (low micro DG scenario on Figure 2.18) and active management without tap changers constitutes the least- reinforcement cost option in scenarios where the severity of the voltage problems is relatively low (medium and high load scenarios on Figure 2.18).

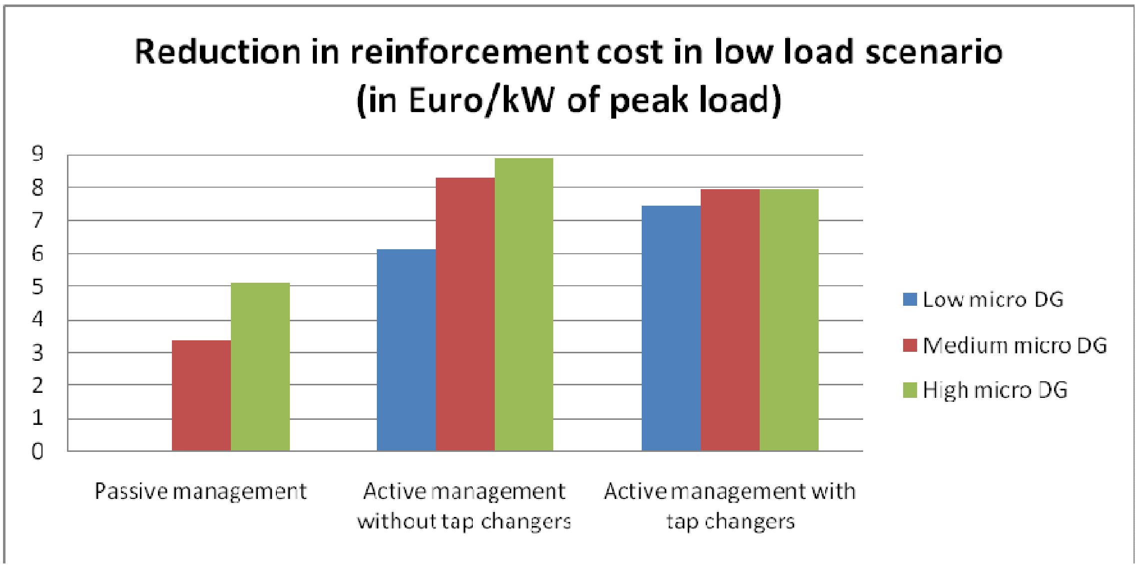


Figure 2.18. Parametric analysis of the reduction in reinforcement cost

As the micro DG penetration increases, the losses reduction with respect to the base case becomes more significant, as larger part of the power required by the load is supplied locally, and thus the power flows on the network are reduced. **Losses under passive management are lower** because the feeders suffering from voltage problems are replaced with feeders of smaller resistance (which is not the case under active management); this difference becomes less apparent as micro DG penetration is increased and load is decreased, since the severity of the arising voltage problems is reduced, and thus the replacement of feeders under passive management becomes less significant (Figure 2.19).

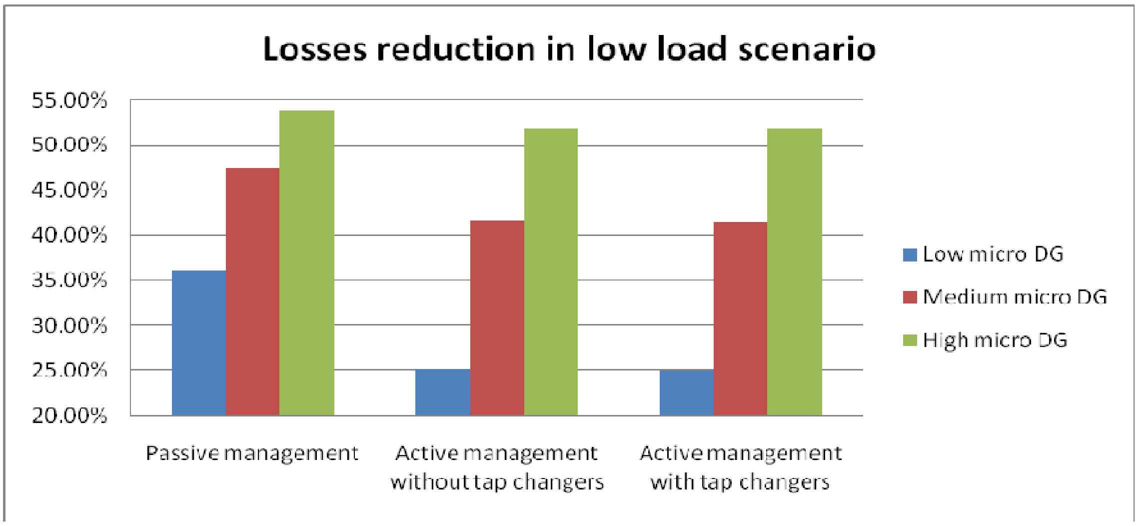


Figure 2.19. Parametric analysis of the reduction in losses

As the micro DG penetration increases the total network cost is reduced, since this trend is observed in both reinforcement cost and cost of losses; **active management reduces further the total network cost**, since its positive impact on the reinforcement cost is much more significant than its negative impact on the (cost of) losses (Figure 2.20).

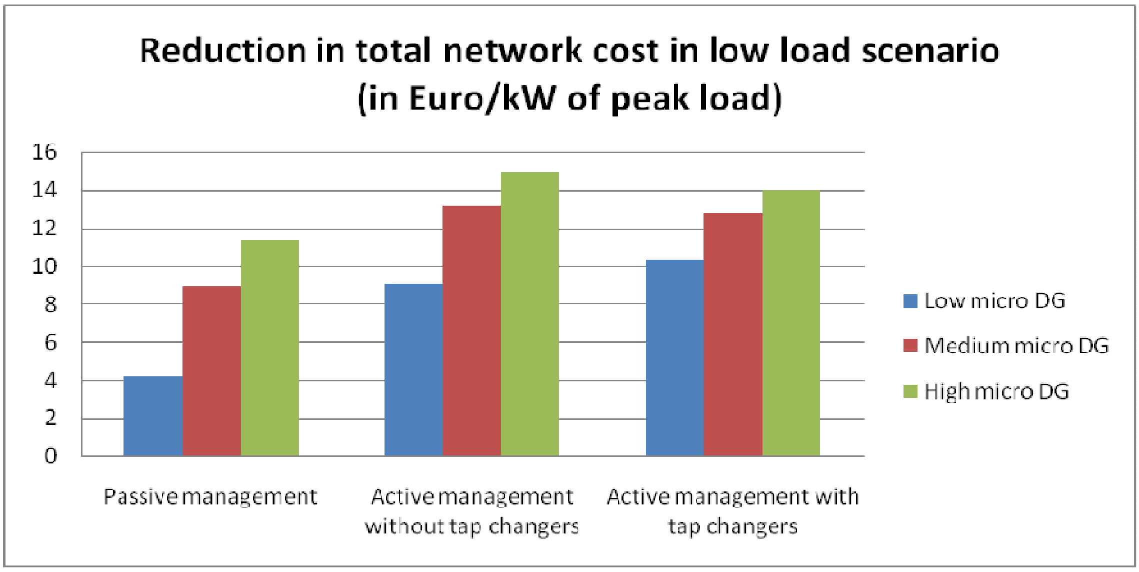


Figure 2.20. Parametric analysis of the reduction in total network cost

The installation of **micro DG reduces the maximum power flow on the GSP and alters the shape of the aggregate demand curve of the FYROM distribution network** (Figure 2.21): micro PV generators (which constitute the largest part of micro DG) change radically the shape of the curve at morning and afternoon hours (as a result the time that the morning peak occurs in a spring/autumn weekday is altered) and micro CHP generators change slightly the shape of the curve at evening hours (as a result the time that the night peak occurs in a spring/autumn weekday is altered in the high micro DG case), due to the characteristics of their generation profile. These effects have potential impacts on **transmission investment** and **central generation scheduling** decisions.

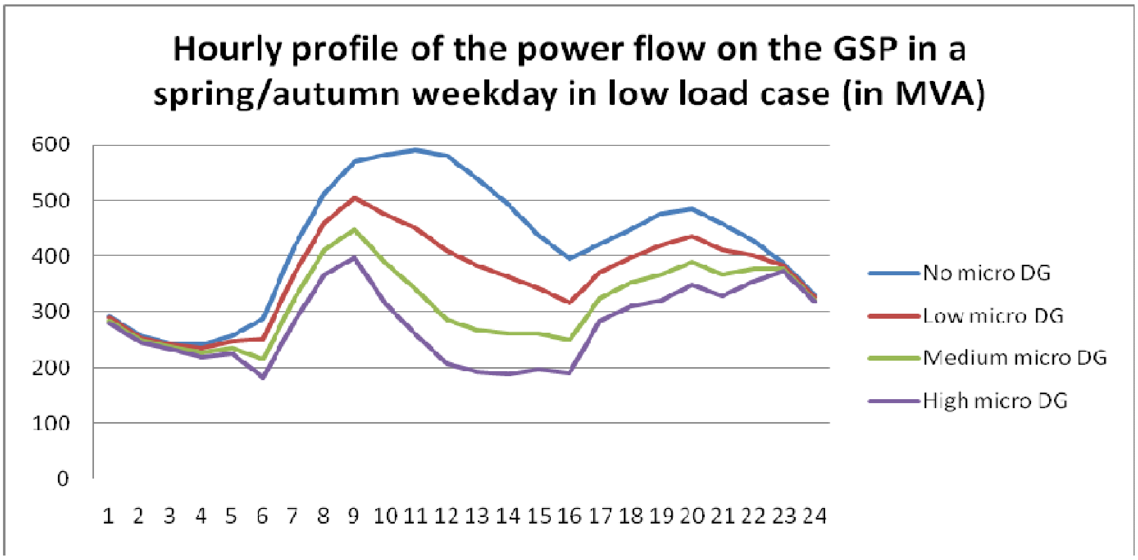


Figure 2.21. Parametric analysis of the changes in the aggregate demand curve

Micro DG reduces CO_2 emissions since it reduces losses and it displaces part of the central electricity production (micro CHP generators also displace part of the heat production by conventional boilers). For a certain emission factor of the marginal plant of central generation, the emissions reduction with respect to the base case (no DG) increases with the micro DG penetration, as the losses reduction and the micro DG energy production become more significant (Figure 2.22).

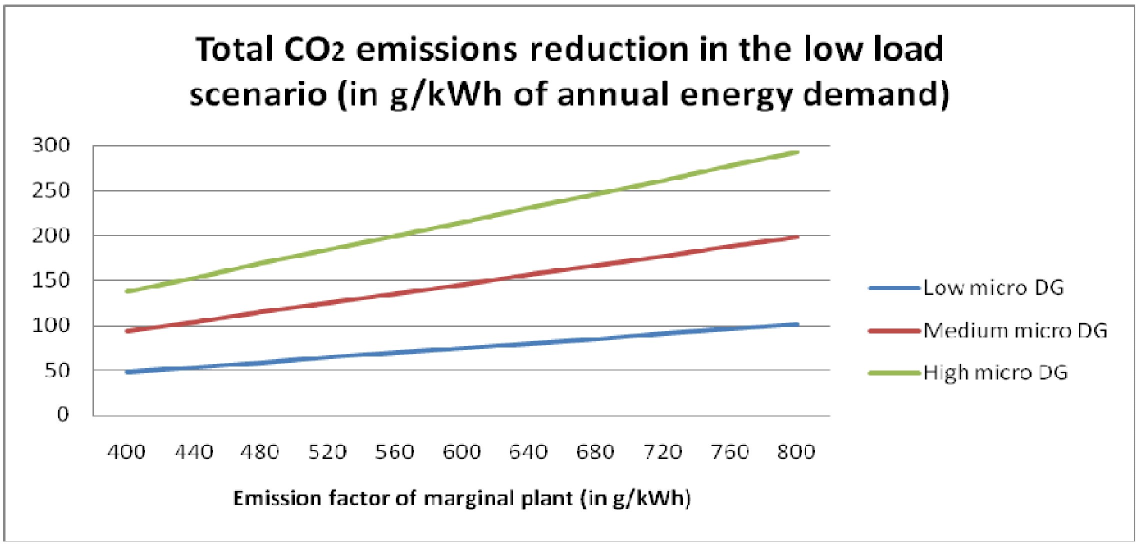


Figure 2.22. Parametric analysis of the environmental benefits of micro DG

2.5 Northern and central European scenario analyses: UK

2.5.1 Parametric assessment of micro DG and AM on current networks

Just as in the Polish and FYROM networks, the whole reinforcement in both low and high load scenarios is demand-driven, and consequently **as the micro DG penetration increases, the reinforcement cost is reduced**; in the low load case, no reinforcement is required with a high micro DG penetration and thus the deployment of different strategies does not affect the reinforcement cost (Figure 2.23). The deployment of **active management reduces further the reinforcement cost** under each of the rest demand-micro DG combinations and more specifically the active management strategy giving the lowest reinforcement cost is **AM with tap changers**, because the voltage problems arising are severe enough to economically justify the installation of tap changers.

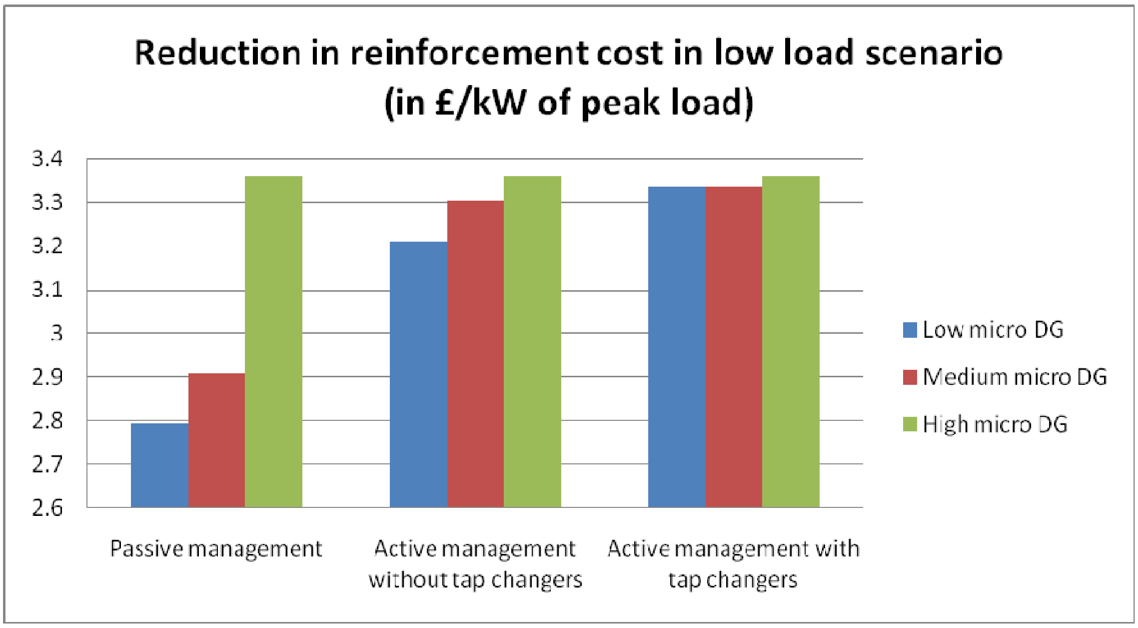


Figure 2.23. Parametric analysis of the reduction in reinforcement cost

In the low load scenario, when we move from low to medium micro DG penetration, the power flow from the GSP to the demand decreases (as more of the power required by the load is supplied by micro DG) and thus **losses are reduced**; on the other hand, when we move from medium to high micro DG penetration, the **power flows are reversed** (since DG capacity is higher than the load) and these reverse flows are so high that the **losses are increased** (Figure 2.24).

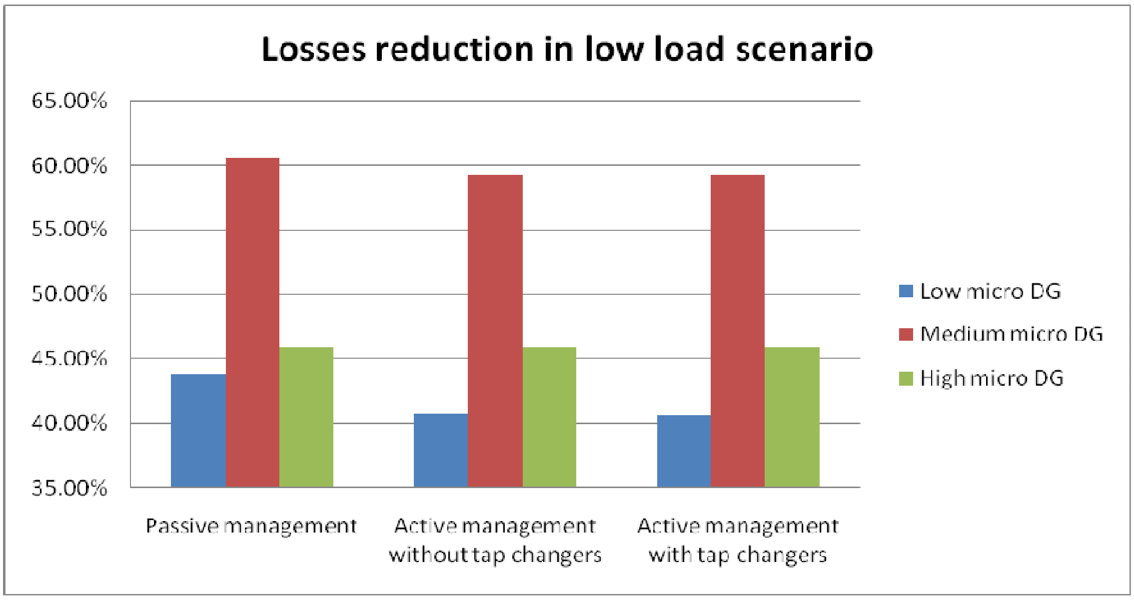


Figure 2.24. Parametric analysis of the reduction in losses

In the low load scenario, even though high micro DG penetration gives zero reinforcement cost, medium micro DG penetration is characterized by the lowest total network cost since it gives the lowest (cost of) losses (Figure 2.25); in the high load scenario, high micro DG penetration is characterized by the lowest total network cost because it gives both the lowest reinforcement cost and the lowest (cost of) losses. **Active management reduces further the total network cost** in both load scenarios, because its positive impact on the reinforcement cost is much more significant than its negative impact on the (cost of) losses.

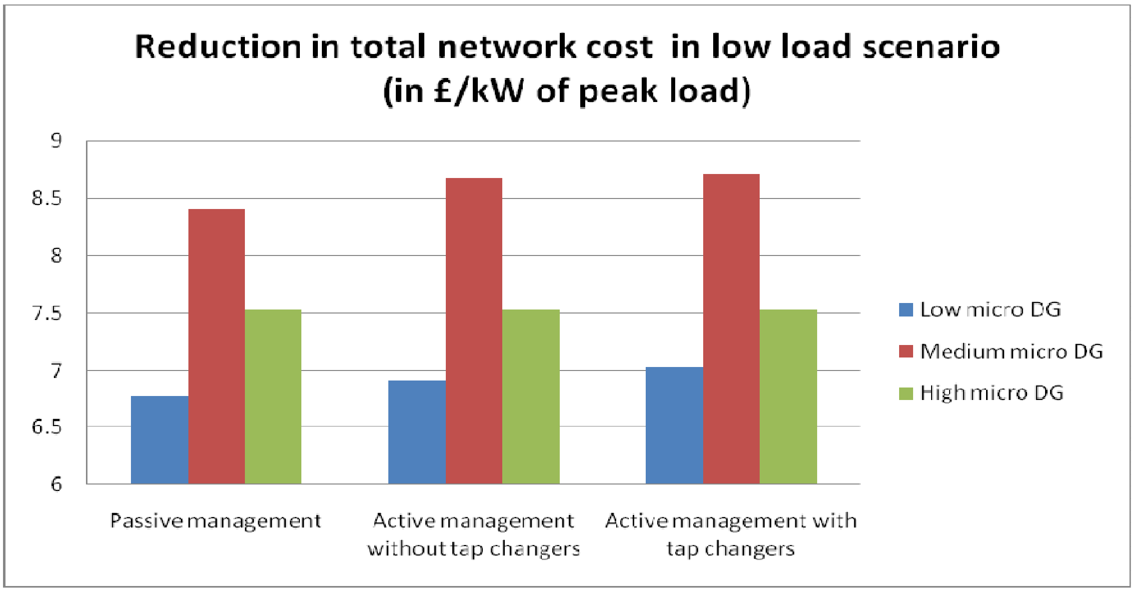


Figure 2.25. Parametric analysis of the reduction in total network cost

While in the low load scenario the **incremental benefit of micro DG** on the total network cost (value of the next kW of micro DG) decreases as its penetration increases for every operating strategy , in the high load scenario the **saturation effect** on this incremental benefit is observed (Figure 2.26) under passive management: it increases when we move from low to medium micro DG penetration (because the benefits from a low penetration are so limited that there is significant room for beneficial impacts from extra micro DG capacity) and it decreases when we move from medium to high micro DG penetration (because the benefits from a medium penetration are so significant that the room for beneficial impacts from extra micro DG capacity is limited).

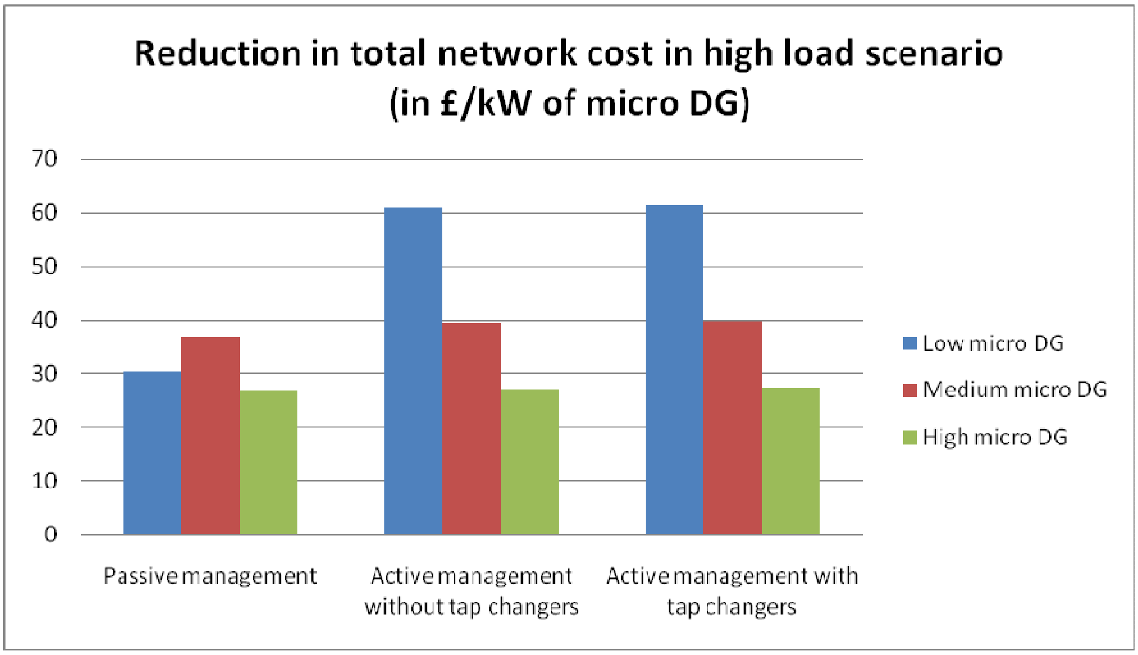


Figure 2.26. Parametric analysis of the incremental benefit of micro DG

2.6 Northern and central European scenario analyses: Germany

2.6.1 Dynamic assessment of DG and AM based on partners' scenarios

The German distribution network is a **strong network** with low losses and able to accommodate the envisaged DG penetration and demand evolution **without thermal and voltage problems**. On the other hand, depending on the short circuit capacity headroom available in the existing switchgear, **reinforcement due to increased short circuit levels (caused by DG)** is likely. Figure 2.27 presents the network investment required to overcome short circuit problems in each of the examined time windows, with 10% headroom requiring 20kV and 110kV switchgear replacement, and the rest of the headroom requiring only replacement of 20kV switchgear.

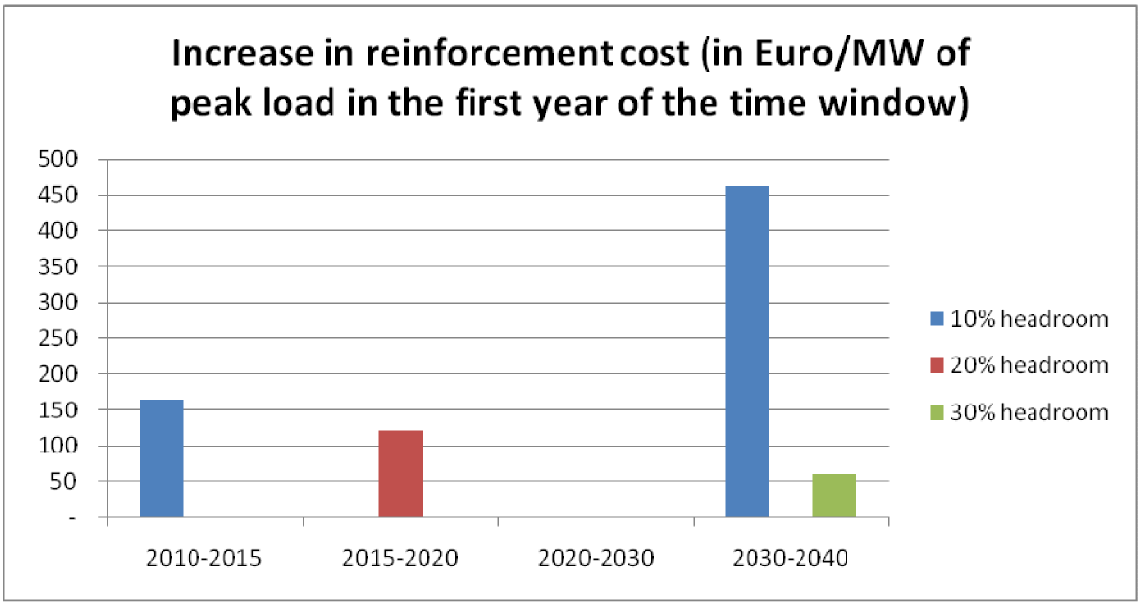


Figure 2.27. Increase in reinforcement cost in each time window

As shown in Figure 2.28, **losses decrease with the installation of DG** since part of the power required by the load is supplied locally, and thus the power flows on the network are reduced; this reduction in losses increases in the future as DG penetration increases much faster than the demand. It is noted that circuit losses decrease dramatically compared to transformer losses.

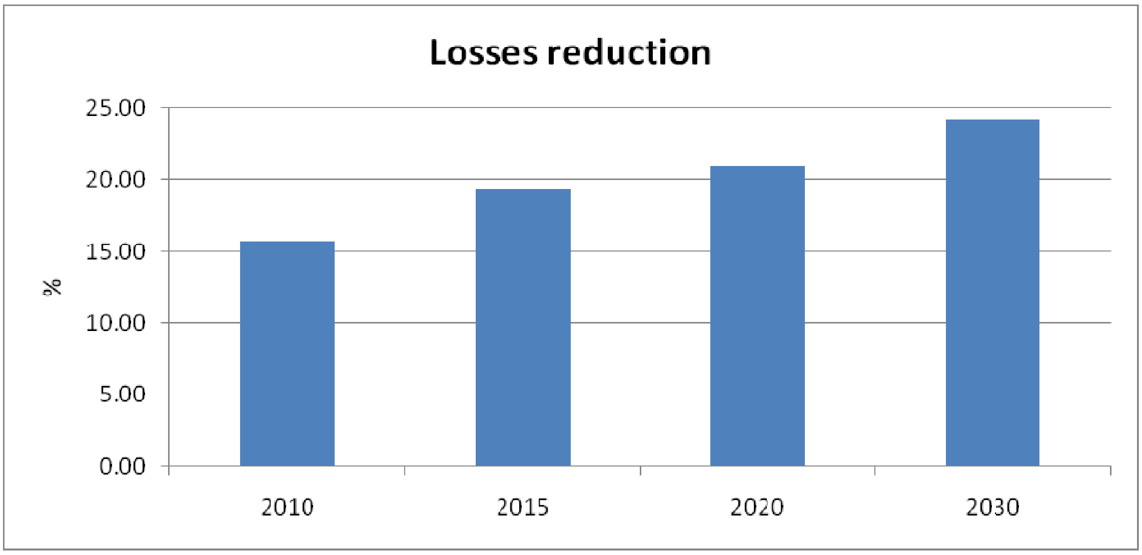


Figure 2.28. Losses reduction in each yearly snapshot

Overall, **network cost decreases** by the installation of DG (Figure 2.29), thank to losses reduction, although DG penetration is likely to require switchgear reinforcement because of increased short circuit levels.

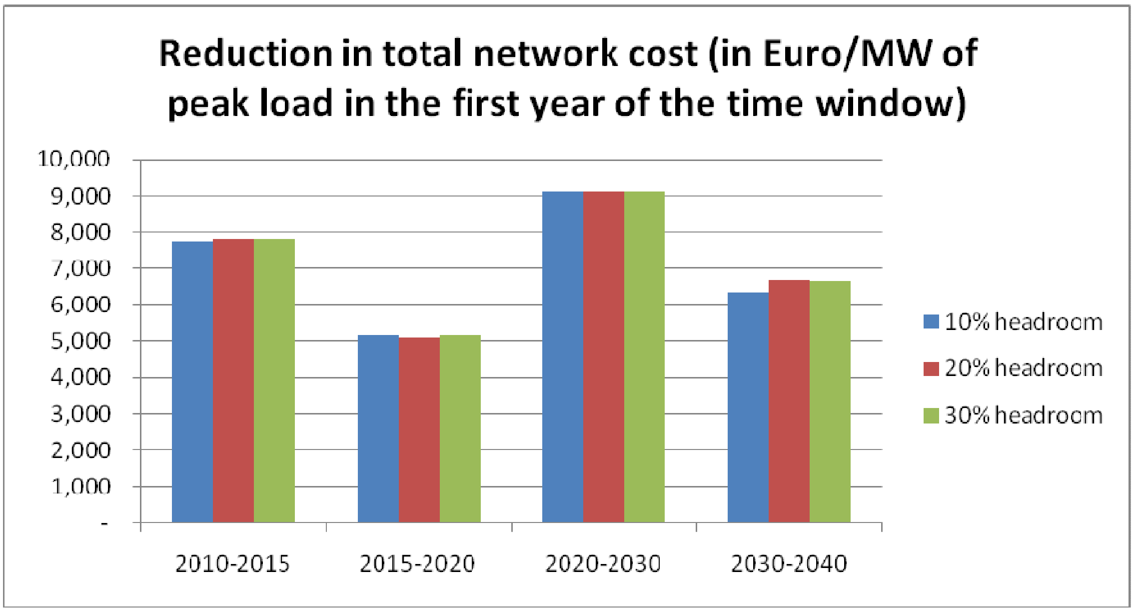


Figure 2.29. Reduction in total network cost in each time window

2.6.2 Parametric assessment of micro DG and AM on current networks

The micro DG penetration and the demand envisaged can be accommodated **without thermal and voltage problems**. On the other hand, depending on the short circuit capacity headroom available in the existing 0.4kV switchgear, **reinforcement due to increased short circuit levels (caused by micro DG)** is likely (Figure 2.30).

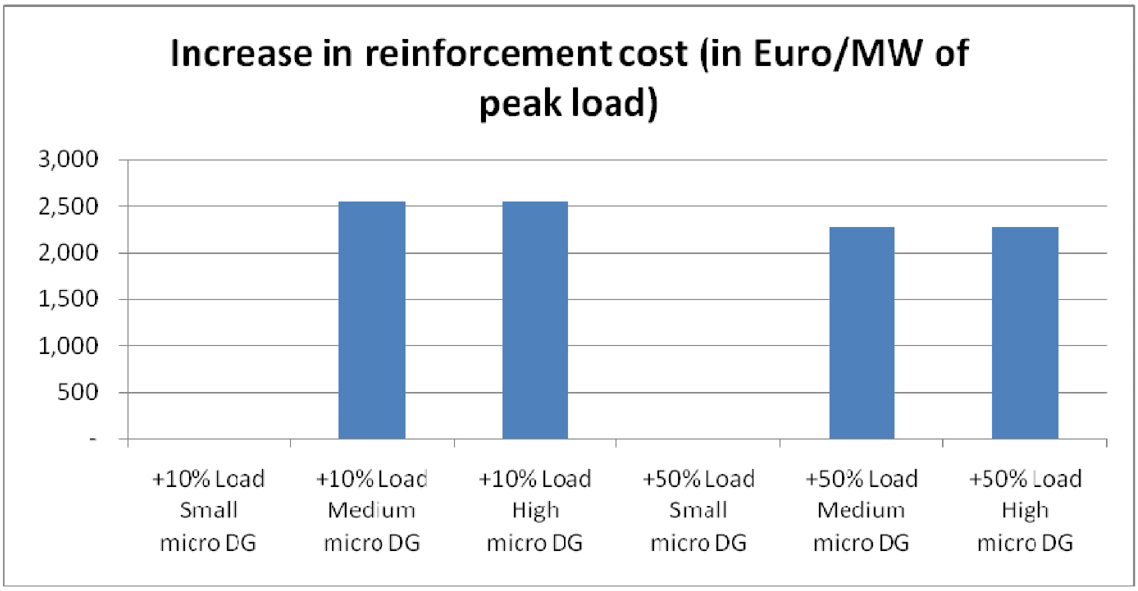


Figure 2.30. Parametric analysis of the increase in reinforcement cost

Losses decrease with increasing micro DG penetration as larger part of the power required by the load is supplied locally, and thus the power flows on the network are reduced. It is noted that circuit losses decrease dramatically compared to transformer losses, since no-load losses constitute the majority of the latter. The total losses reduction is shown in Figure 2.31.

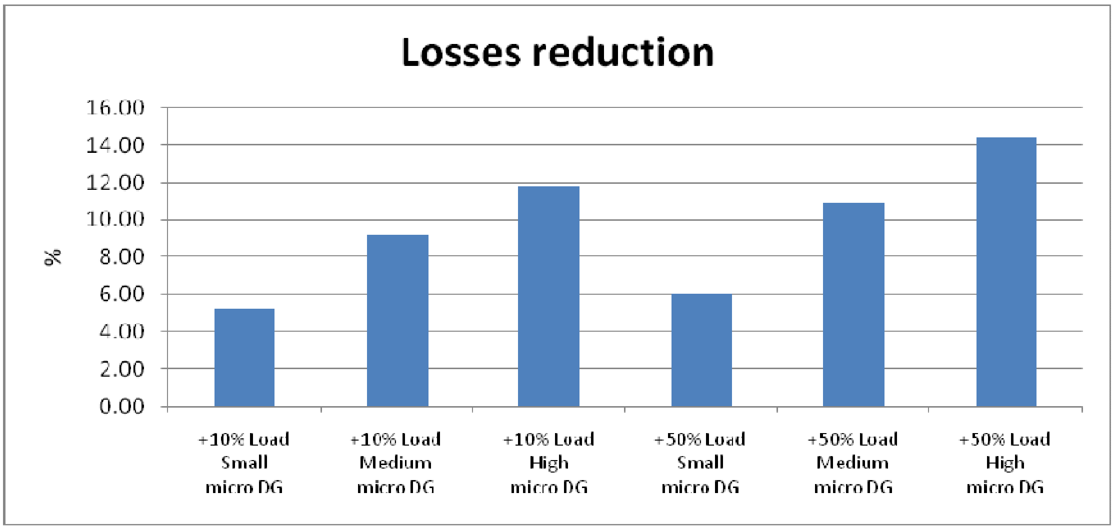


Figure 2.31. Parametric analysis of the reduction in losses

Overall, **network cost decreases** by the installation of micro DG thank to losses reduction, although increased micro DG penetration is likely to require switchgear reinforcement because of increased short circuit levels.

Finally, the installation of micro DG **reduces the maximum GSP power flow and alters the shape of the aggregate demand curve of the German distribution network** (as a result the time that the peak occurs in a winter weekday is changed), as shown in Figure 2.32, with potential impacts on **transmission investment** and **central generation scheduling** decisions.

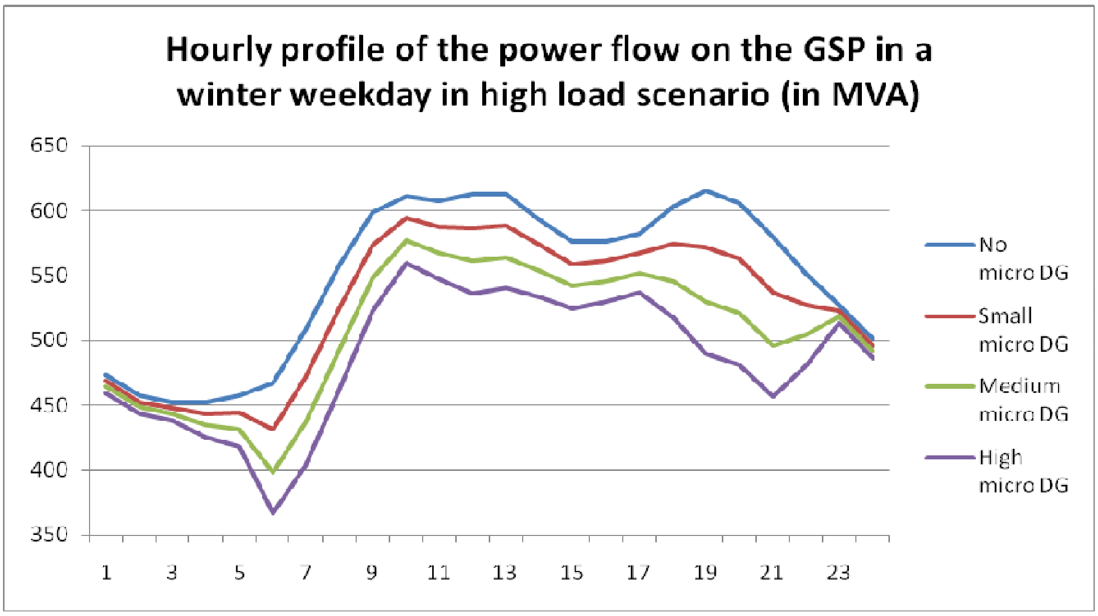


Figure 2.32. Parametric analysis of the changes in the aggregate demand curve

2.7 Northern and central European scenario analyses: Netherlands

2.7.1 Dynamic assessment of DG and AM based on partners' scenarios

The Dutch network is so strong that is able to accommodate the envisaged DG penetration and demand evolution **without thermal, voltage and short circuit level problems**.

Total **losses increase with the installation of DG** (Figure 2.33), since significant reverse power flows emerge in part of the networks where the installed DG capacity is relatively large in comparison with the demand; Figure 2.34 reveals that this is the case in the 11kV voltage level. This increase in losses becomes more significant throughout the years, as the DG penetration increases faster than the demand.

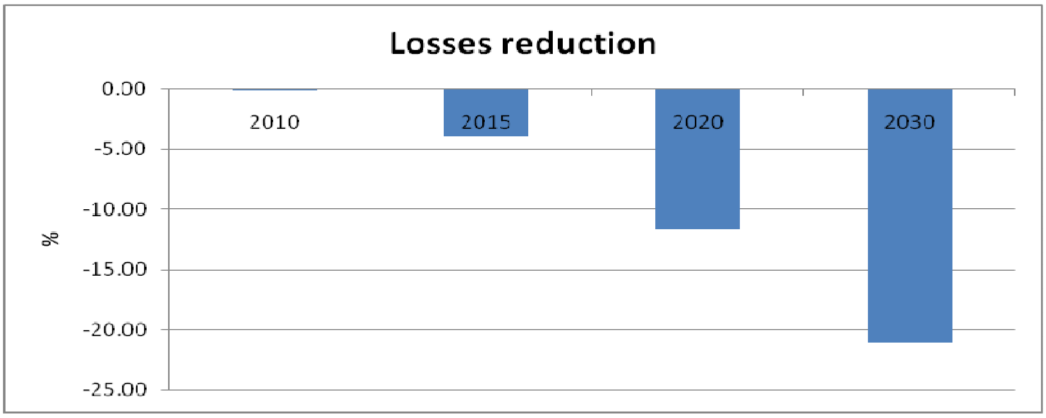


Figure 2.33. Losses reduction in each yearly snapshot

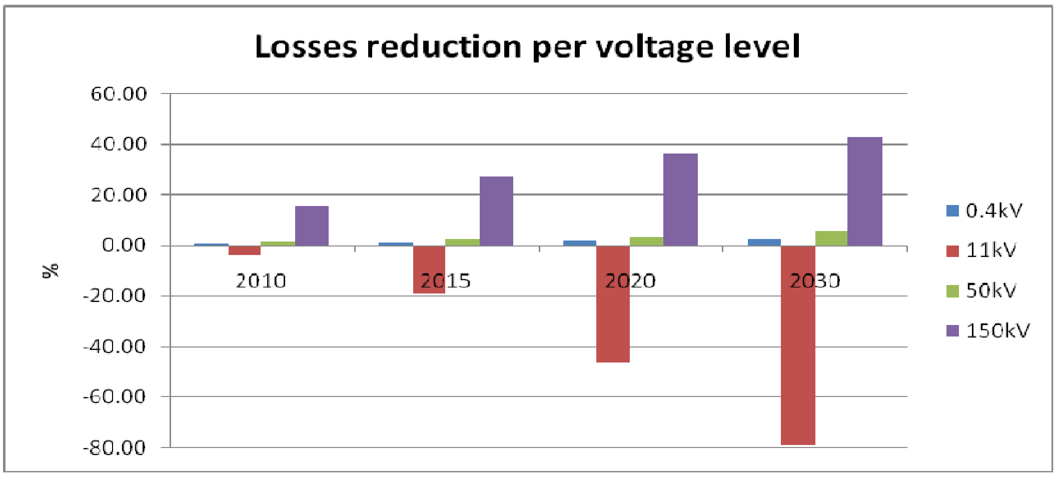


Figure 2.34. Losses reduction per voltage level in each yearly snapshot

Overall, **the foreseen DG penetration increases the total network cost**, since it increases the (cost of) losses while it does not affect the reinforcement cost.

The foreseen DG penetration **reduces the maximum GSP power flow and alters the shape of the aggregate demand curve of the Dutch distribution network** (Figure 2.35), with potential impacts on **transmission investment** and **central generation scheduling** decisions.

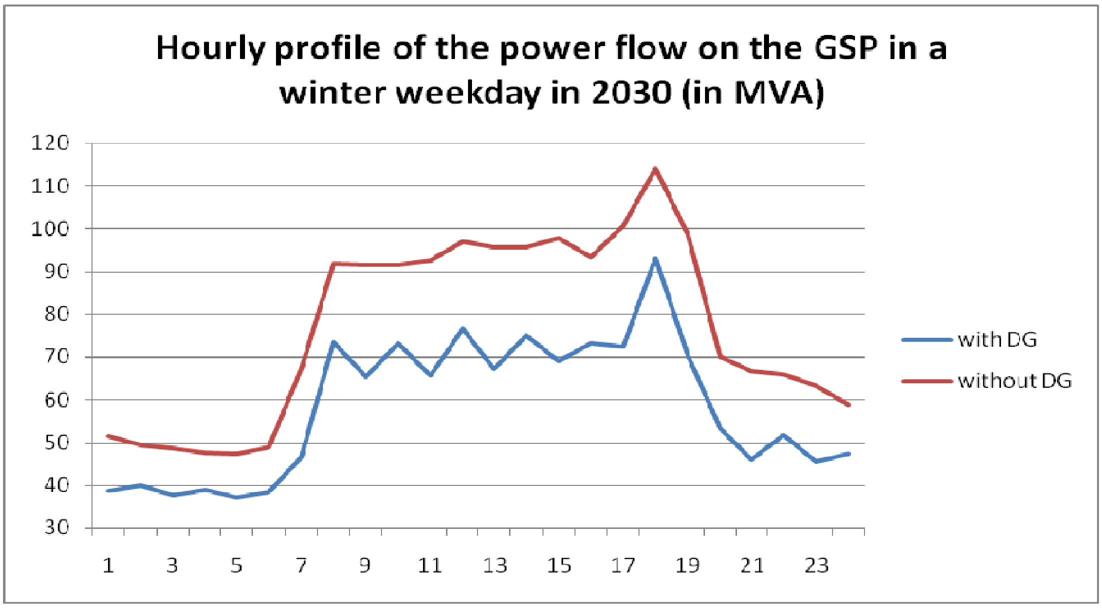


Figure 2.35. Changes in the aggregate demand curve

2.7.2 Parametric assessment of micro DG and AM on current networks

The Dutch network is able to accommodate the envisaged micro DG penetration and demand **without thermal, voltage and short circuit problems**.

As shown in Figure 2.36, **losses decrease with increasing micro DG penetration**, as larger part of the power required by the load is supplied locally, and thus the power flows on the network are reduced. It is noted that circuit losses decrease dramatically compared to transformer losses since no-load losses constitute the majority of the latter (Figure 2.37).

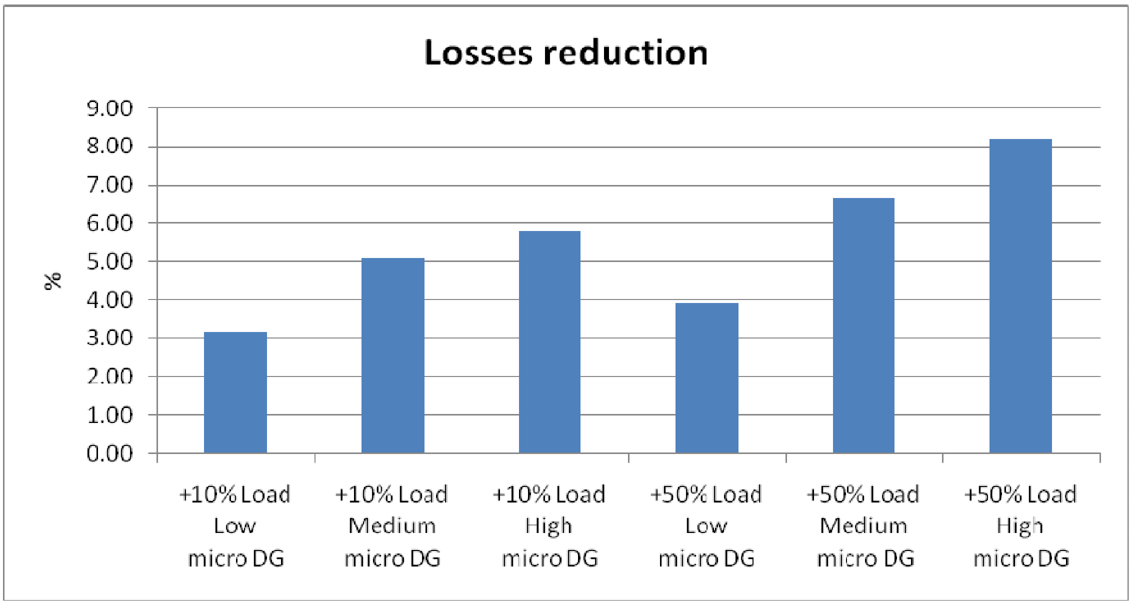


Figure 2.36. Parametric analysis of the reduction in losses

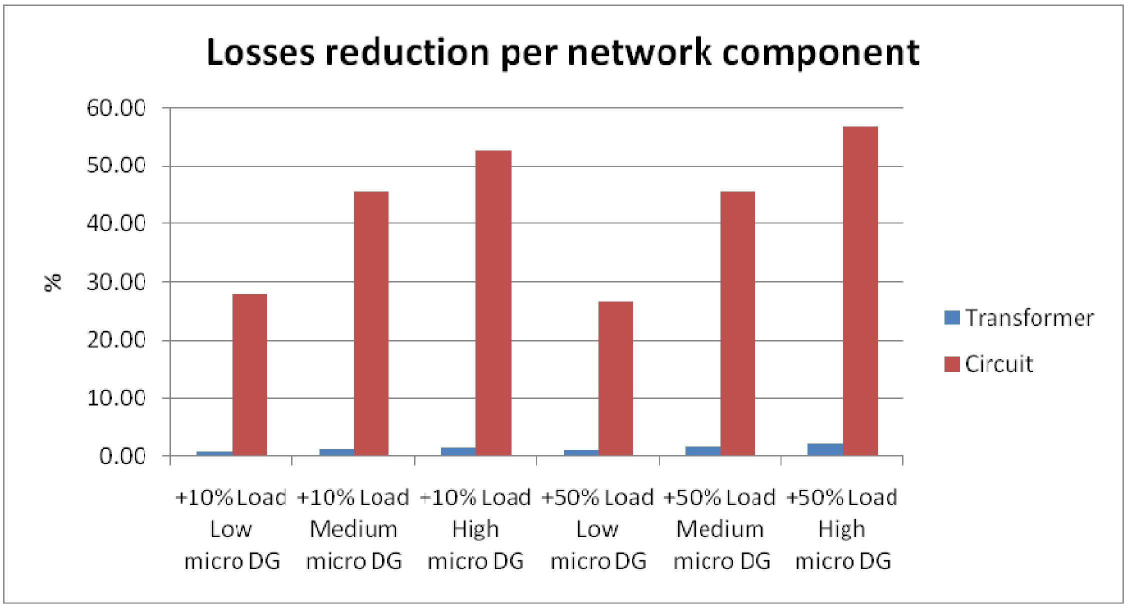


Figure 2.37. Parametric analysis of the reduction in losses per network component

The **total network cost is reduced when micro DG penetration is increased**, since the cost of losses follows the same trend while the reinforcement cost is not affected.

2.8 Northern and central European scenario analyses: Comparative analysis

2.8.1 Dynamic assessment of DG and AM based on partners' scenarios

In this section, a comparison of the results acquired from our dynamic analysis on distribution networks of three different countries is carried out. More specifically, these three distribution networks are compared on the basis of the impacts of (the foreseen in each network) DG and the implementation of AM with respect to the base case (no DG and passive management) over the next 20 years. Our analysis on the distribution network of **Poland** has included the deployment of different operating strategies (passive management, active management without tap changers and active management with tap changers), since voltage problems emerge in this network; for simplicity reasons, only the results which correspond to the optimal operating strategy (the one giving the lowest total network cost) are presented, and thus the impact of AM is inherently included in the following results. Moreover, our analysis on the distribution network of **Germany** has showed that the installation of DG causes fault level problems and the cost of the required reinforcement depends on the available break rating headroom of the existing switchboards; for simplicity reasons, only the results which correspond to the worst case scenario (10% headroom) are presented.

1.Benefits related to reinforcement

The reduction in the reinforcement cost by the installation of DG for the different distribution networks in each of the examined time windows is presented on Figure 2.38. We can observe that the installation of DG has different impacts on the reinforcement cost of different networks:

i) DG has a very significant positive impact on the reinforcement cost of the **Polish** network, since most of the required reinforcement is driven by demand (thus there is ground for DG to mitigate the reinforcement cost) and its largest part is related to violations of voltage limits (thus there is ground for active management to mitigate the reinforcement cost)

ii) DG has no impact on the reinforcement cost of the **Dutch** network since this network is so strong that no reinforcement is required without or with DG installed

iii) DG has a marginal negative impact on the reinforcement cost of the strong **German** network in the time windows 2010-2015 and 2030-2040 since the installation of DG causes fault level problems and thus drives the replacement of some switchboards; on the other hand, it has no impact on the reinforcement cost in the time windows 2015-2020 and 2020-2030

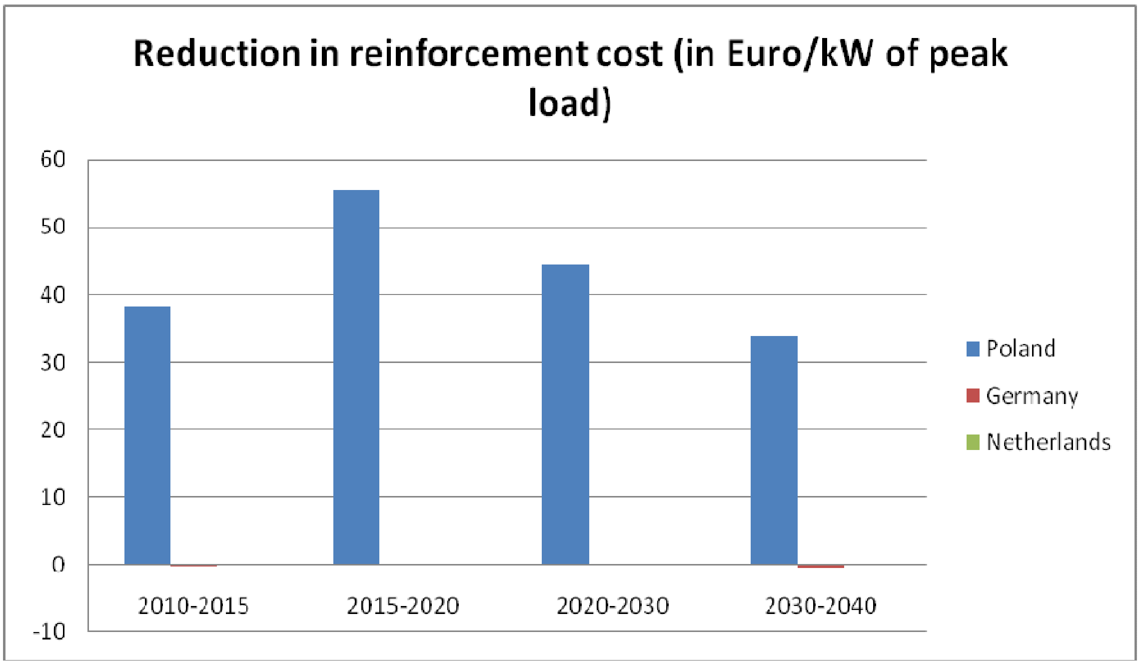


Figure 2.38. Comparison of the reduction in reinforcement cost

2.Benefits related to losses

The losses reduction by the installation of DG for the different distribution networks in each of the examined yearly snapshots is depicted on Figure 2.39. We can observe that the installation of DG has different impacts on the losses of different networks:

i) DG has a positive impact on the losses of the **German** network, as part of the power required by the load is supplied locally and consequently the power flows from the GSP to the demand are reduced; this positive impact increases as years pass by, since DG penetration increases much faster than the demand and consequently greater part of the demand is supplied locally

ii) DG has a negative impact on the losses of the **Dutch** network, since significant reverse power flows emerge in parts of the network where the installed DG capacity is relatively large in comparison with the load; this negative impact increases as the years pass by since DG penetration increases much faster than the demand and consequently the emerging reverse power flows become more significant

iii) DG has a negative impact on the losses of the **Polish** network, because the strategy deployed in the DG case (active management without tap changers) is characterized by very high losses because it involves the connection of very large capacitive compensation which creates significant reverse power flows;

this negative impact increases as the years pass by since this capacitive compensation increases faster than the demand and consequently the emerging reverse power flows become more significant

Figure 2.39. Comparison of the reduction in losses

3.Benefits related to total network cost

The reduction in total network cost (sum of the reduction in reinforcement cost and the reduction in the cost of losses) by the installation of DG for the different distribution networks in each of the examined time windows is presented on Figure 2.40. We can observe that the installation of DG has different impacts on the total network cost of different networks:

i) DG has a significant positive impact on the total network cost of the **Polish** network, since its positive impact on reinforcement cost is extremely higher than its negative impact on (the cost of) losses

ii) DG has a moderate positive impact on the total network cost of the **German** network, since its positive impact on (the cost of) losses is much higher than its marginal negative impact on reinforcement cost

iii) DG has a marginal negative impact on the total network cost of the **Dutch** network, since it increases (the cost of) losses and it does not affect reinforcement cost

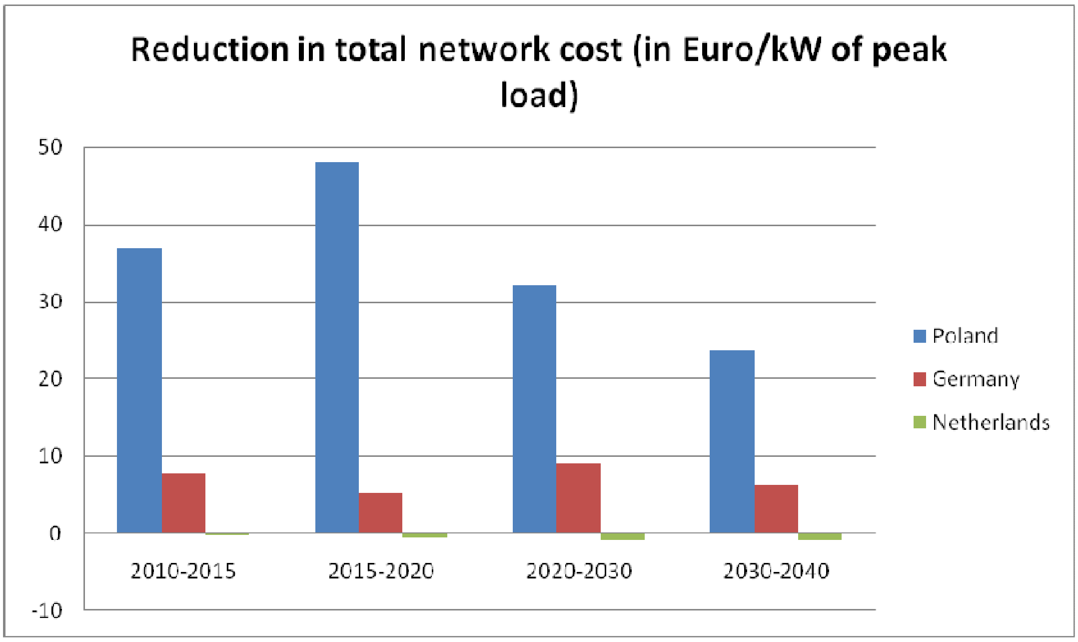


Figure 2.40. Comparison of the reduction in total network cost

The network which is benefited the most by the installation of DG is the **Polish** one, where there is significant ground for DG and AM to mitigate the required reinforcement. The incremental benefit of DG on the total network cost (value of the next kW of DG) for the different distribution networks in each of the examined time windows is presented on Figure 2.41; similar trends are observed here, with the highest value of DG being observed in the **Polish** network.

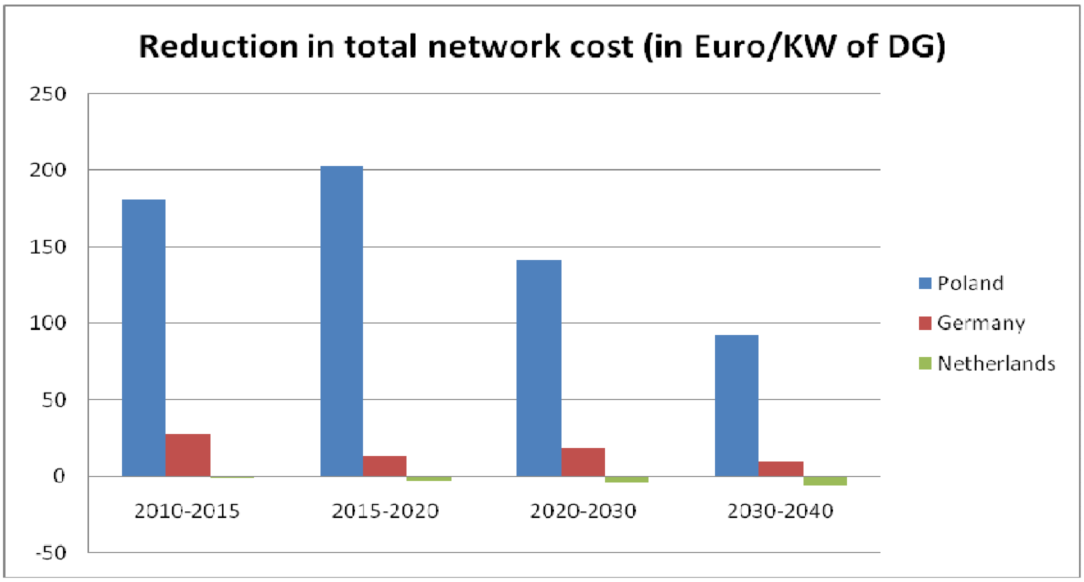


Figure 2.41. Comparison of the incremental benefit of DG

2.8.2 Parametric assessment of micro DG and AM on current networks

In this section, a comparison of the results acquired from our parametric analysis on distribution networks of five different countries is carried out. More specifically, these five distribution networks are compared on the basis of the impacts of micro DG and AM with respect to the base case (no micro DG and passive management). Our analysis on the distribution networks of **Poland**, **FYROM** and **UK** has included the deployment of different operating strategies (passive management, active management without tap changers and active management with tap changers), since voltage problems emerge in these networks; for simplicity reasons, only the results which correspond to the optimal operating strategy (the one giving the lowest total network cost) are presented, and thus the impact of AM is inherently included in the following results. Moreover, our analysis on the distribution network of **Germany** has showed that the installation of micro DG causes fault level problems and the cost of the required reinforcement depends on the available break rating headroom of the existing switchboards; for simplicity reasons, only the results which correspond to the worst case scenario (10% headroom) are presented.

1.Benefits related to reinforcement

The reduction in the annualized reinforcement cost by the installation of micro DG for the different distribution networks in the low and the high load scenario is presented on Figures 2.42 and 2.43 respectively. We can observe that the installation of micro DG has different impacts on the reinforcement cost of different networks:

i) in the **Polish**, **FYROM** and **UK** networks micro DG has a positive impact on the reinforcement cost since reinforcement is driven by demand (thus there is ground for micro DG to mitigate the reinforcement cost) and its largest part is related to violations of voltage limits (thus there is ground for active management to mitigate the reinforcement cost); the network which is benefited the most by the installation of micro DG in the low load scenario is the **Polish** one, while the greatest benefit by the installation of micro DG in the high load scenario is observed in the **UK** network

ii) in the **Dutch** network micro DG has no impact on the reinforcement cost since this network is so strong that no reinforcement is required without or with micro DG installed

iii) in the **German** network micro DG has a negative impact on the reinforcement cost since the installation of micro DG causes fault level problems and thus drives the replacement of some switchboards

As expected, for a specific demand, the positive (**Poland, FYROM, UK**) and negative (**Germany**) impact of micro DG generally increases with its penetration.

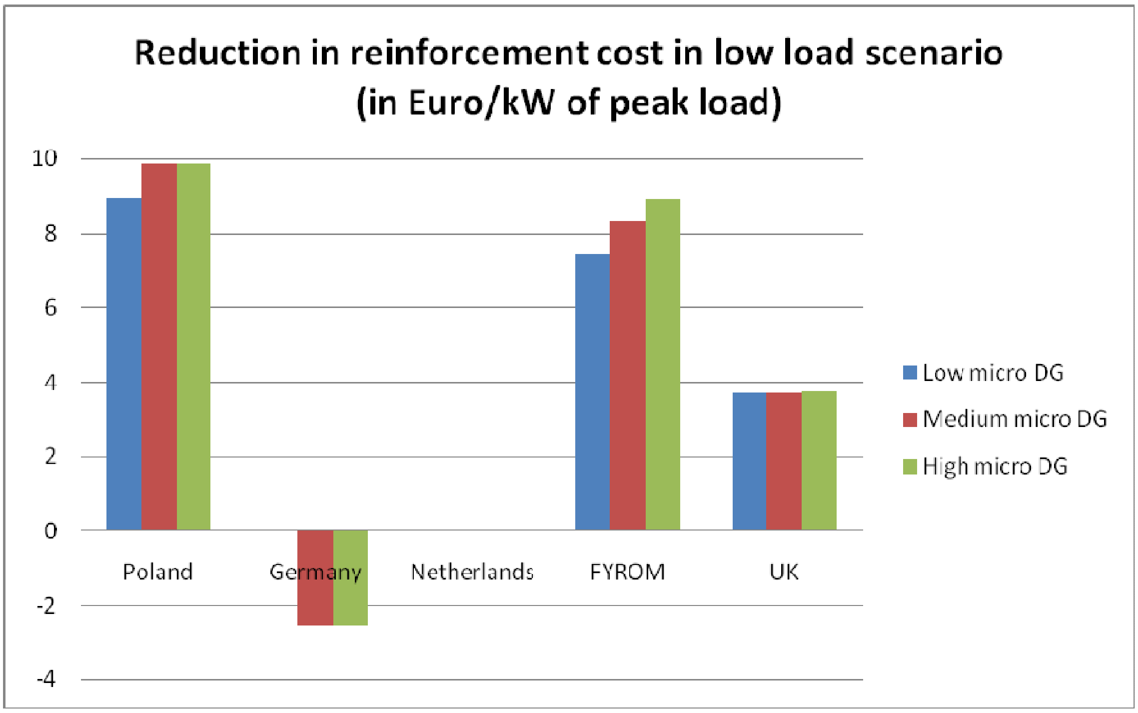


Figure 2.42. Comparison of the reduction in reinforcement cost in low load scenario

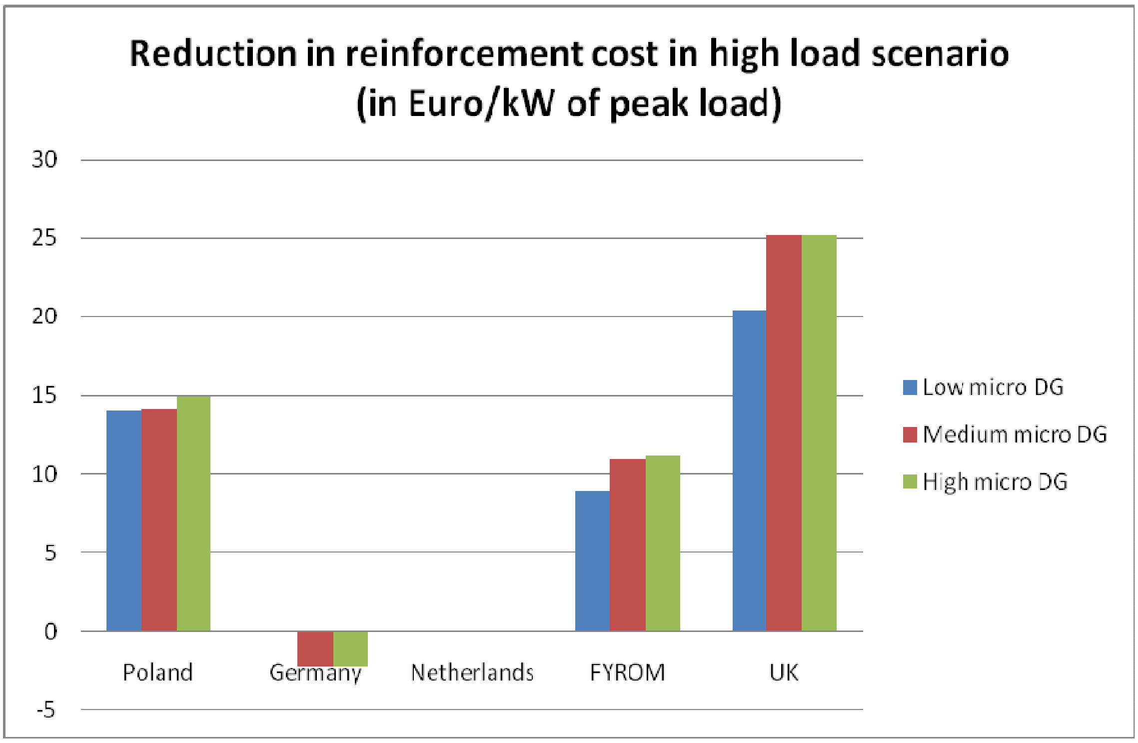


Figure 2.43. Comparison of the reduction in reinforcement cost in high load scenario

2.Benefits related to losses

The losses reduction by the installation of micro DG for the different distribution networks in the low and the high load scenario is depicted on Figures 2.44 and 2.45 respectively. We can observe that the installation of micro DG has always a positive impact on losses, as part of the power required by the load is supplied locally and consequently the power flows from the GSP to the demand are reduced; the only exemption is the high load – low micro DG scenario in the **Polish** distribution network, where the strategy deployed in the micro DG case (active management without tap changers) is characterized by very high losses because it involves the connection of very large capacitive compensation which creates significant reverse power flows. We can also see that the losses reduction increases with the micro DG penetration; the only exemption is the low load scenario in the **UK** network where an increase from medium to high micro DG penetration results in significant reverse power flows and higher losses. Finally, while micro DG brings significant losses reduction (up to 60%) in the **Polish**, **FYROM** and **UK** networks, it does not have the same impact on the strong **German** and **Dutch** networks (the respective reduction is less than 15% in every scenario).

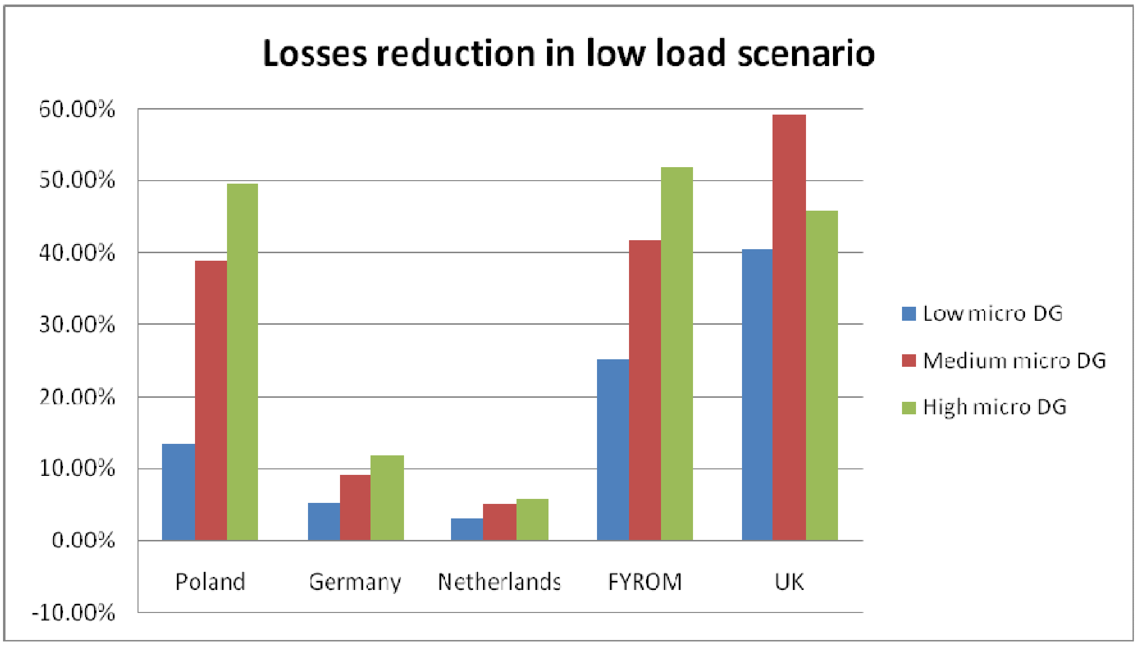


Figure 2.44. Comparison of the reduction in losses in low load scenario

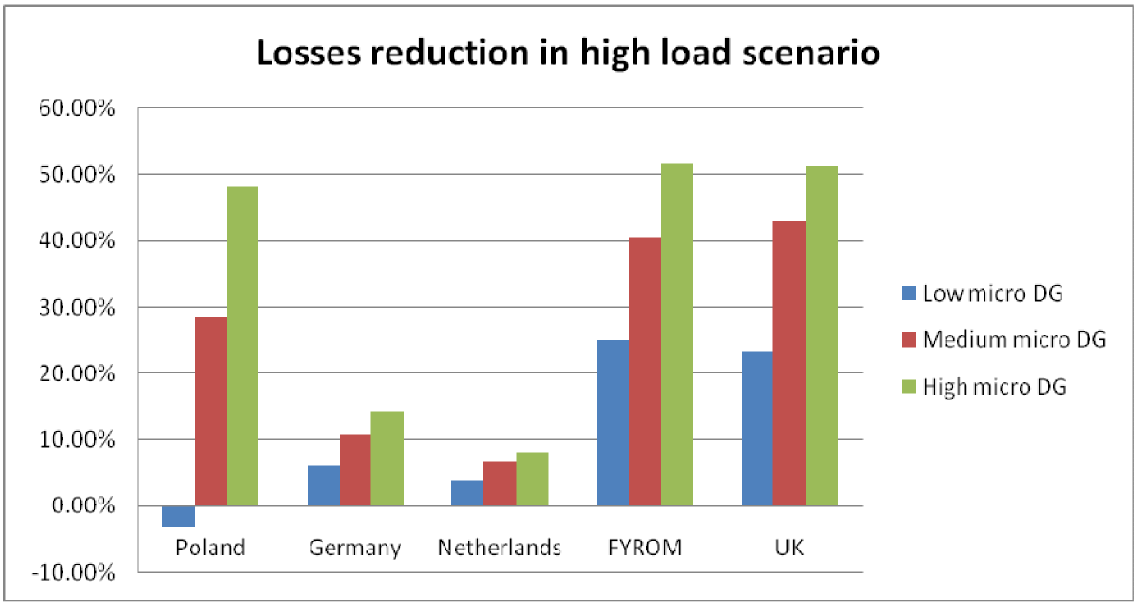


Figure 2.45. Comparison of the reduction in losses in high load scenario

3.Benefits related to total network cost

The reduction in total network cost (sum of the reduction in the annualized reinforcement cost and the reduction in the annual cost of losses) by the installation of micro DG for the different distribution networks in the low and the high load scenario is presented on Figures 2.46 and 2.47 respectively. We can observe that the installation of micro DG has always a positive impact on the total network cost:

i) in the **Polish**, **FYROM** and **UK** networks, micro DG reduces both the reinforcement cost (Figures 2.42 and 2.43) and the cost of losses (since it reduces losses as shown on Figures 2.44 and 2.45; the only exemption is the high load-low micro DG scenario in the **Polish** network but the increase in the cost of losses is extremely smaller than the reduction in the reinforcement cost),

ii) in the **Dutch** network, micro DG reduces the cost of losses (since it reduces losses), while it has no impact on the reinforcement cost and

iii) in the **German** network, even though micro DG has a negative impact on the reinforcement cost it has a much higher positive impact on the cost of losses (since it reduces losses).

Regarding the impacts of different micro DG penetrations, we can see that:

i) in the **Polish** and **FYROM** networks, the total network cost is decreased when the micro DG penetration is increased, since both the reinforcement cost and the cost of losses follow the same trend,

ii) in the **UK** network, the same trend is observed in the high load scenario; in the low load scenario however, even though the reinforcement cost is decreased when the micro DG penetration is increased, the medium micro DG penetration gives the optimal total network cost, since it results in much lower losses than the high penetration,

iii) in the **Dutch** network, the total network cost is decreased when the micro DG penetration is increased, since the cost of losses follows the same trend and the micro DG penetration has no impact on the reinforcement cost and

iv) in the **German** network, even though an increase in micro DG penetration causes an increase in reinforcement cost, it results in a much higher decrease in the cost of losses and thus in an increase in the total network cost.

A huge difference is observed between the benefits of micro DG on the strong **Dutch** and **German** networks (where micro DG does not reduce the reinforcement cost) and the weaker **Polish**, **FYROM** and **UK** networks (where micro DG reduces significantly the reinforcement cost). The network which is benefited the most by the installation of micro DG in the low load scenario is the **FYROM** one; in the high load scenario on the other hand, the greatest benefit from the installation of micro DG is observed in the **UK** network.

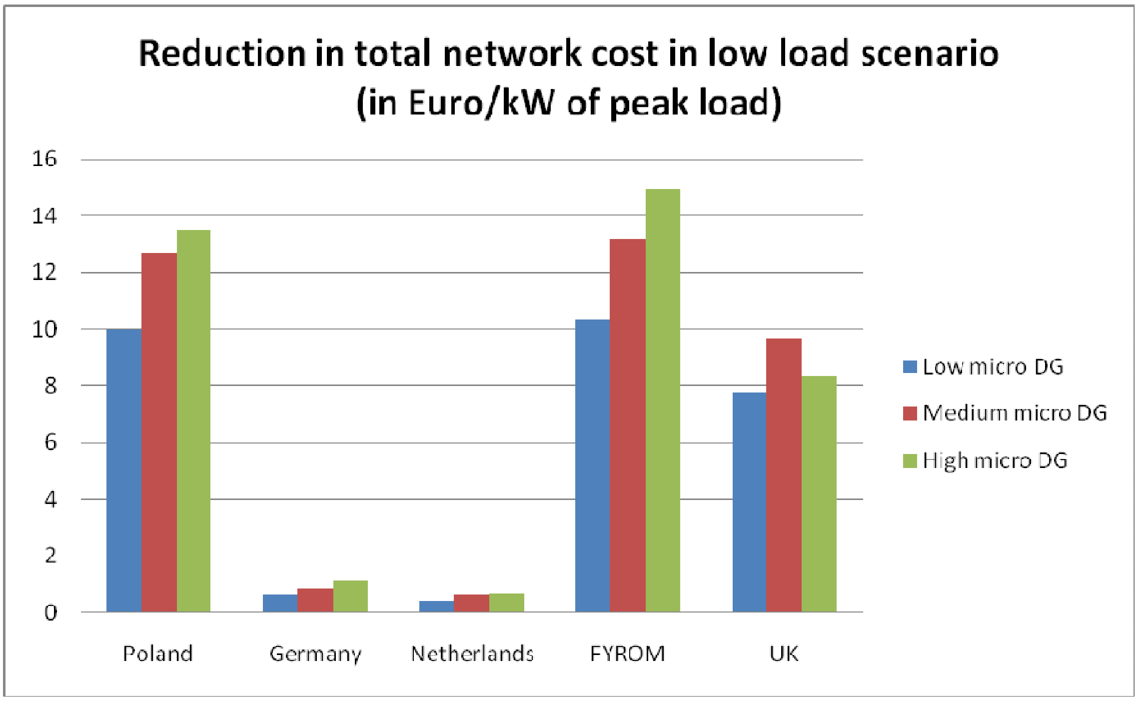


Figure 2.46. Comparison of the reduction in total network cost in low load scenario

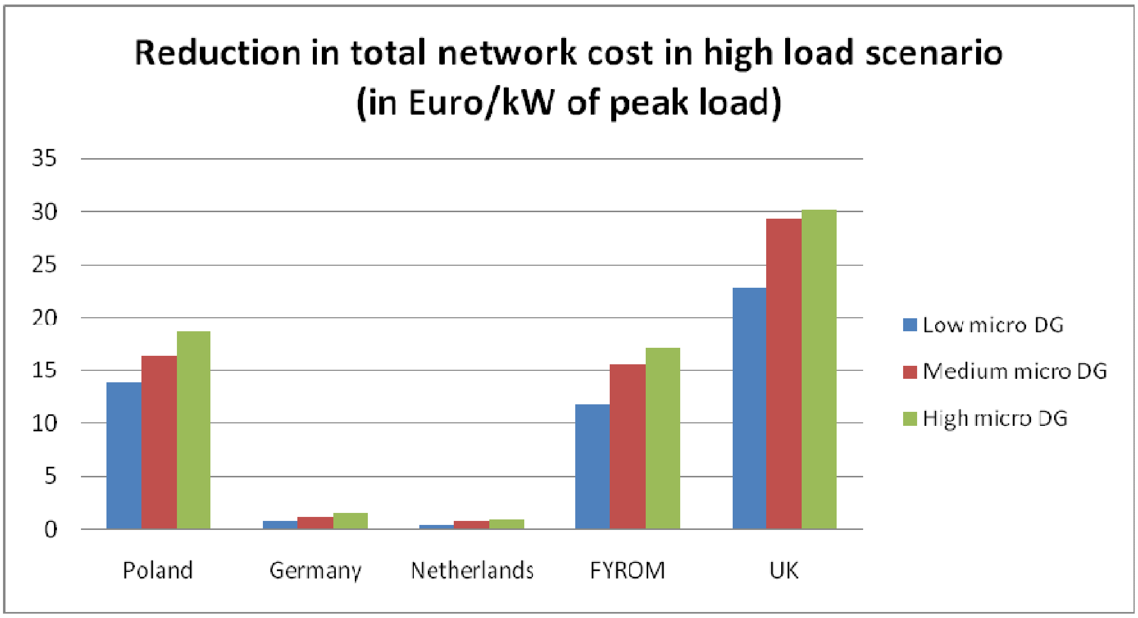


Figure 2.47. Comparison of the reduction in total network cost in high load scenario

The incremental benefit of micro DG on the total network cost (value of the next kW of micro DG) for the different distribution networks in the low and the high load scenario is depicted on Figures 2.48 and 2.49 respectively. For each network, as the micro DG penetration is increased (for a specific level of demand) and as the demand is decreased (for a specific level of micro DG penetration), the available room for beneficial effects of extra micro DG capacity is reduced and thus the value of the next kW of micro DG is decreased. The networks with the highest value of micro DG in the low and the high load scenario are the **Polish** and the **UK** network respectively.

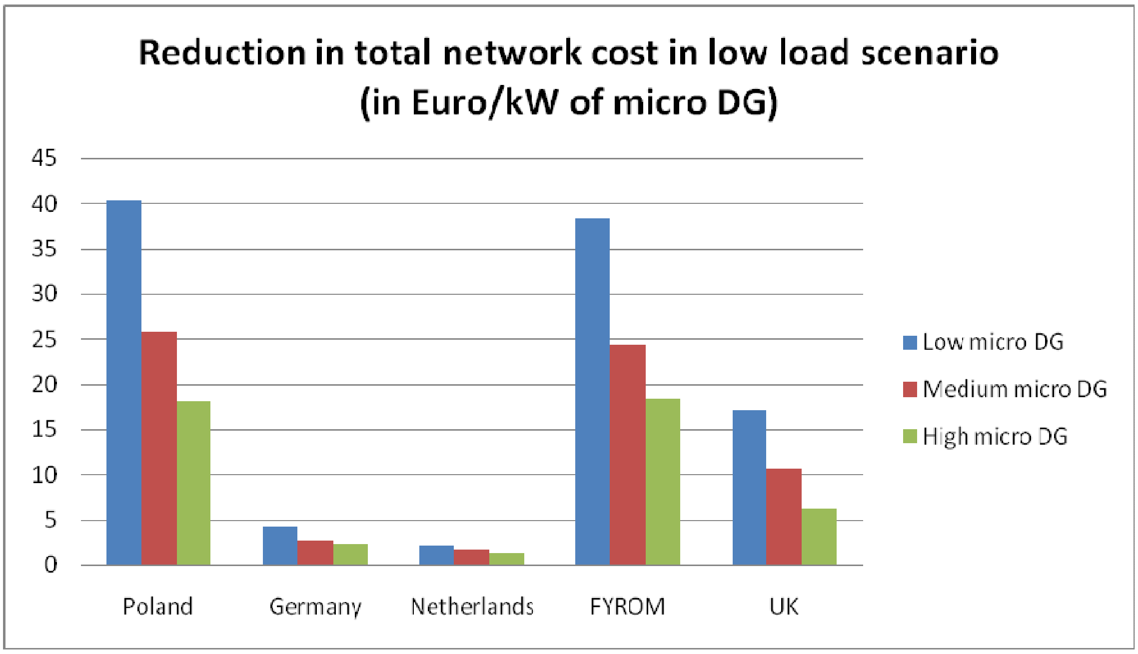


Figure 2.48. Comparison of the incremental benefit of micro DG in low load scenario

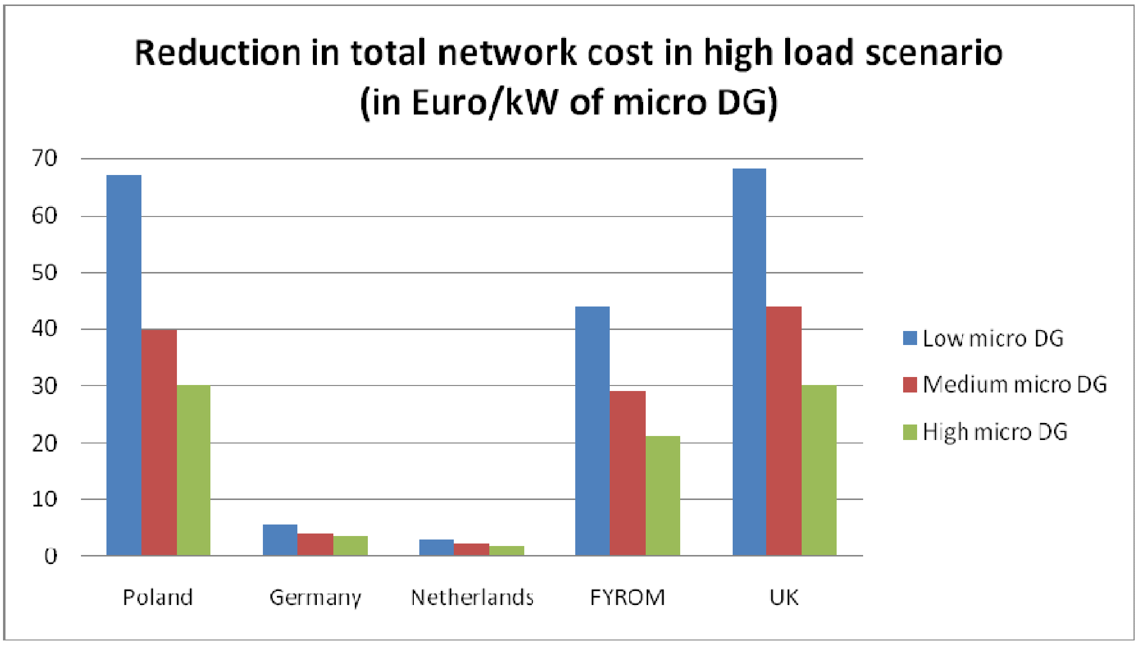


Figure 2.49. Comparison of the incremental benefit of micro DG in high load scenario

2.9 Southern European scenario analyses: Greece

This Section briefly summarizes the main findings by NTUA about the infrastructure impact of Microgrids on a typical distribution network in Greece, characterised by a number of micro-PV units spread across the network coupled with relatively larger dispatchable generators. The details of the methodology, assumptions and calculations can be found in Annex H2.B.

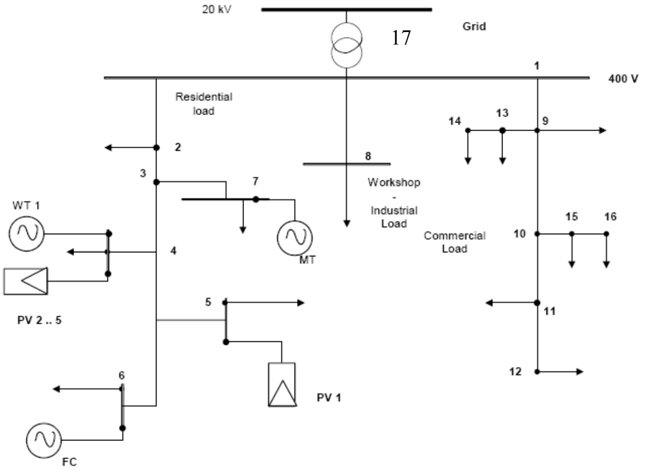
2.9.1 Impact of DG on system flows and investment deferral economic benefits

As discussed above, by using DG technologies to supply locally the demand needs, investment on strategic expensive network upgrades (above all in metropolitan areas) can be deferred. The value of the deferral of these investments depends on the equipment costs and the time by which these investments are deferred. This deferral time depends, in turn, on the size of the DG being installed and the rate at which the local load grows. More specifically, when a new DG system is installed and operates, the currents in some of the network feeders may be reduced, according to the size of DG and its location throughout the network. If the demand across the network continues to grow, certain time will pass before the feeder currents reach the values found before the DG started to operate. The benefit to the distribution utility is immediate: it will take more time for the current on those loaded transformers or feeders to reach the technical limits at which new investments have to be put in place. The benefit is even more evident when the current reduction defers or avoids already scheduled investments. Therefore, the first step towards the quantification of the benefit of transformers or feeders investment deferral is to measure the impact of the DG output on the currents across the distribution network, which can be assessed by running power flow analyses across the network. Once power flows have been run and the impact of DG outputs on network flows has been quantified, it is possible to estimate the time span τ_k by which the presence of DG postpones the need for investment on certain portions of the network. The methodology is detailed in Annex H2.B. As a result, the economic benefits to the utility can be quantified through the temporal value of money. More specifically, the time by which a given investment on a feeder or a group of feeders is delayed is given by the lowest (minimum) deferral time of the feeder or any of the feeders belonging to that particular group. Thereby, the total benefit B_i to the utility given by the Microgrid located at bus i is the sum of all benefits obtained in all groups of feeders owing to time value of money [14], namely

$$B_i = \sum_g C_g \left(1 - \frac{1}{e^{\rho \tau_{gi}}}\right) \qquad (8)$$

2.9.2 Case study application

The methodology presented was applied to the typical Hellenic LV network shown below, characterised by three feeders, one serving a primarily residential area, one serving a small workshop, and one commercial feeder. A variety of DER, such as one MT, one FC, one directly coupled Wind Turbine and several PV units are installed in the residential feeder. It is assumed that all DER produce active power at unity power factor.



Unit ID	Unit Name	Minimum Capacity (kW)	Maximum Capacity (kW)
1	Microturbine	2	30
2	Fuel Cell	1	30
3	WT 1	0.1	15
4	PV 1	0.05	3
5	PV 2	0.05	2.5
6	PV 3	0.05	2.5
7	PV 4	0.05	2.5
8	PV 5	0.05	2.5

Figure 2.50. Hellenic 17-bus test distribution network.

2.9.3 Synthesis of the main results

Many scenarios have been analysed to assess the benefits from DG on investment deferral. In particular, among the other results detailed in Annex H2.B, next pictures show the deferral time and the total network benefit increase with DG penetration.

In terms of strategic considerations, it can be concluded that the deferral time and total economic benefits increase when the DG production of a Microgrid is installed near load pockets and during peak load period. This almost obvious result was not only confirmed but also quantified. In particular, investments on expensive network upgrades can be deferred. The value of the deferral of these investments depends on the investment costs and the time by which these investments are deferred. This deferral time depends, in turn, on the size of the DG being installed and the rate at which the local load grows. Although a quantification of the deferral benefits is extremely complex, the results in the test case show that the relevant correlations are linear.

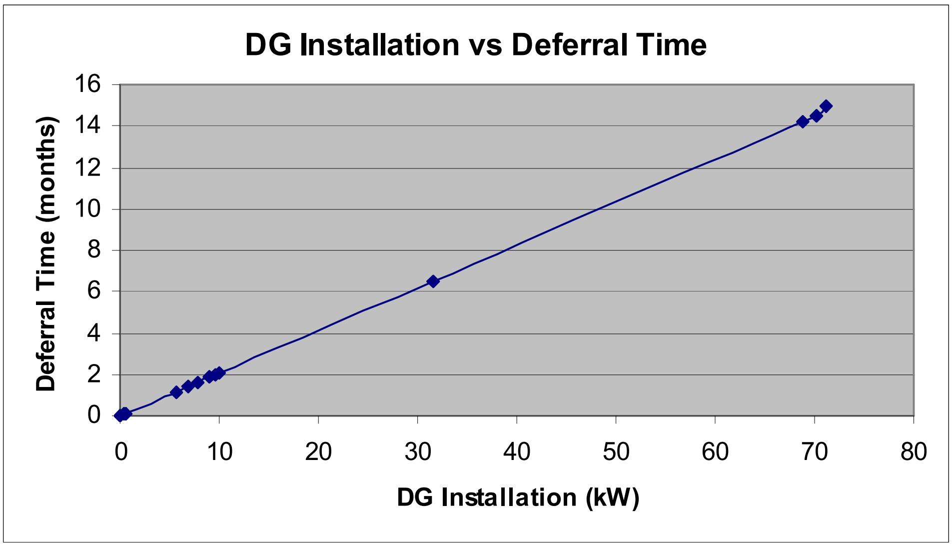


Figure 2.51. Deferral time benefits due to DG in the Hellenic test network.

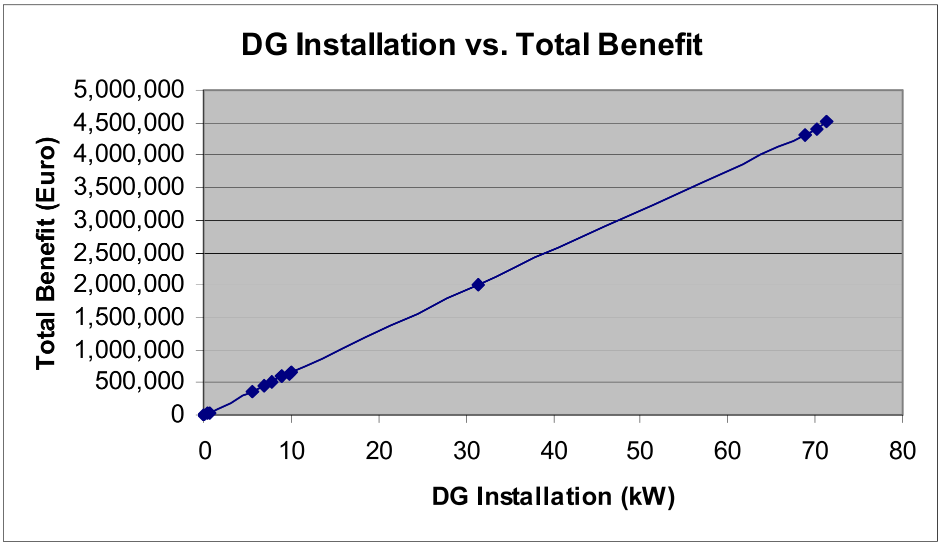


Figure 2.52. Overall cost benefits due to DG network deferral in the Hellenic test network.

2.10 Southern European scenario analyses: Italy

This Section briefly summarizes the main findings by ERSE about the infrastructure impact of PV-based Microgrids on a typical MV distribution network in Italy. The details of the methodology, assumptions and calculations can be found in Annex H2.B.

2.10.1 Network design strategies in the presence of DG

A specific tool has been developed by ERSE for assessment of MV infrastructure development in the presence of DG. The tool designs the network topology and sizes the circuits by minimizing (through heuristic optimization) the overall cost of network investment, maintenance, upgrade and losses, for both normal and emergency conditions, subject to classical network constraints. In order to take into account the uncertainties introduced by DG in the planning process, a probabilistic approach is adopted and a probabilistic load flow (*PLF*) is implemented that takes into account the probability density function (*pdf*) of loads and DG production. For typical distribution planning studies, both loads and generators are represented by means of normal distributions.

As a major feature, the tool allows the planner to consider some of the most important functions of Active Management, namely generation curtailment (in analogy to the GDS analyses illustrated above), load shedding and network reconfiguration.

Resorting to active management is dealt with through a probabilistic approach, whereby the DSO gives customers or producers a certain probability to be shed or disconnected during the most critical hours, guaranteeing normal operation in the rest of the day. However, in many cases the use of active controls is limited to emergency conditions (line faults), that implies a reduced probability of occurrence.

The simulation of AM in the planning methodology allows postponement of investments thanks to the maximum exploitation of the existing assets. On the other hand, as already observed in the GDS analyses above, by maintaining the network close to its thermal capacity limits AM generally results in an increase in losses.

For comparison purposes, simulations are run also with a conventional *"fit and forget"* (F&F) planning policy, that implies the sizing of the distribution system so as to meet technical constraints in the most onerous conditions, both in steady state and emergency conditions: minimum load/maximum generation and maximum load/no generation.

2.10.2 Test network

The test network is a portion of a real 20 kV MV distribution network supplied by one primary substation with two HV/MV transformers rated 16 MVA, feeding 118 MV/LV nodes (52 feeder nodes and 66 lateral nodes). Two main areas can be identified, roughly corresponding to low-density rural centres (4.5 MW of peak load) with long overhead lines and high-density urban/industrial loads (11.9 MW of peak load) with underground cables. The total length of the network is 62.8 km, of which about 80% overhead lines and 20% underground cables. Five typologies of loads have been considered: residential, industrial, tertiary, agricultural and public lighting. Details are provided in Annex H2.B.

2.10.3 Scenarios and planning strategies

The effect of different DG penetration levels and planning approaches on network upgrade costs and losses have been analyzed.

Several scenarios have been considered with increasing levels of penetration of PV generation on residential nodes. This choice is due to the fact that PV generation is presently strongly supported in Italy, with high feed-in tariffs for small plants connected to the LV level, so a significant development is expected in areas with predominant residential characteristics. The percent level of DG penetration has been defined as the ratio of installed capacity to peak load, referred to residential nodes only.

Different planning strategies have been adopted:

- A *probabilistic planning* approach, taking into account load and generation daily profiles discretized into 24 hourly intervals.
- A conventional *F&F*, or *worst-case*, criterion; daily power profiles and the coincidence factor between loads and DG are not considered.
- A *probabilistic planning* approach with the possibility to consider at a design stage the resort to *Active Management* options (DSM) to solve violations; it has been assumed that residential customers participate to a load control program by accepting a maximum demand reduction of 50%.

2.10.4 Assessment of the impact of totally autonomous Microgrids on network planning

Among other analyses (detailed in Annex H2.B) relevant to DG operation within a Multi-Microgrids framework (in which active control actions are carried out at the MV level), specific analyses have been run for Microgrids assumed to be *totally autonomous* in terms of energy balance, thanks to the integration of responsive loads, controllable generators and storage systems. Each LV MG has been ideally represented, at the MV level, as a node behaving as a load coupled with a generator, in such as way that each Microgrid results in zero net power flow (both active and reactive) at the corresponding MV/LV substation transformer. A totally autonomous Microgrid requires a DG penetration level of 100% in energy terms. Given the assumed daily profiles, this implies an installed DG capacity of about 180% of peak load; consequently, the assessment of the benefits of Microgrids has been made with comparison to the scenario of 180% DG penetration.

The following pictures show the comparison of investment costs, losses costs, and energy losses (in percentage of total energy delivered to loads) for three different scenarios:

- base case without DG,
- 180% of “simple” DG power penetration,
- 180% of DG power penetration (100% in energy terms) in the form of integrated microgrids;

and for three different planning strategies:

- probabilistic approach with daily profiles,
- fit&forget,
- DSM.

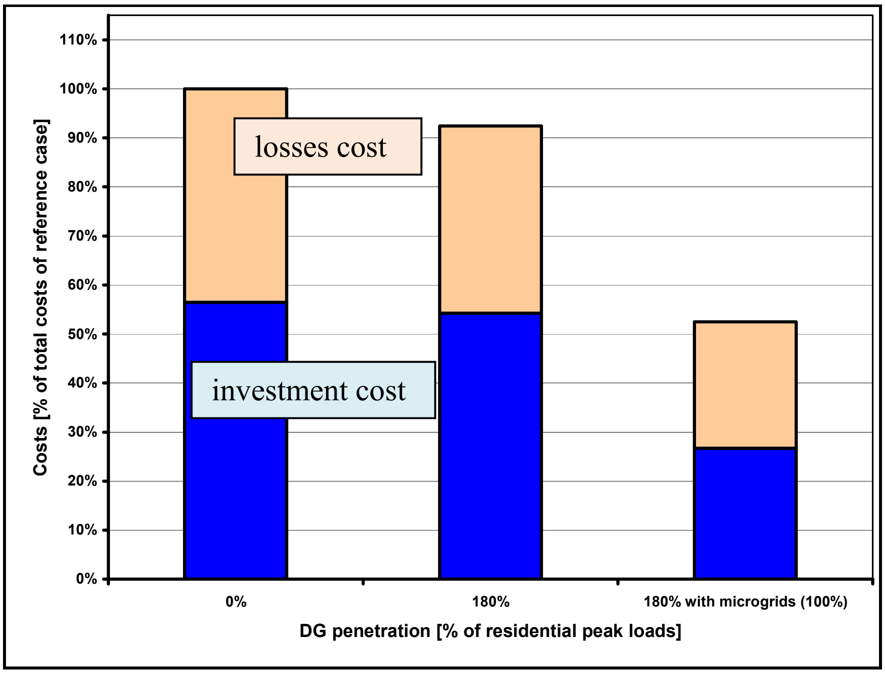


Figure 2.53. Costs of the network designed considering daily profiles for loads and generators

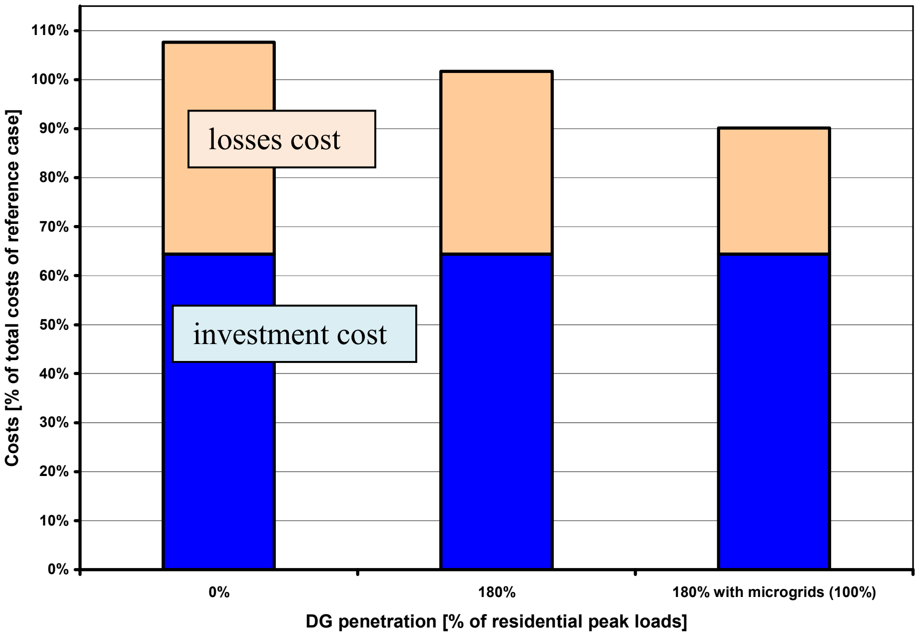


Figure 2.54. Costs of the network designed based on the traditional fit&forget approach

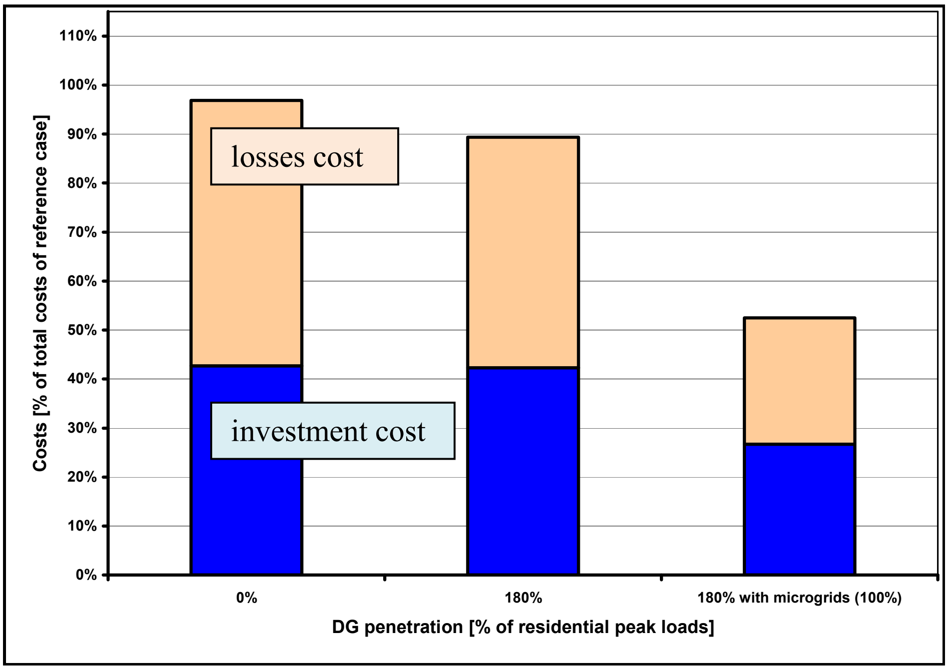


Figure 2.55. Costs of the network designed considering daily curves and possible load shedding (DSM) actions

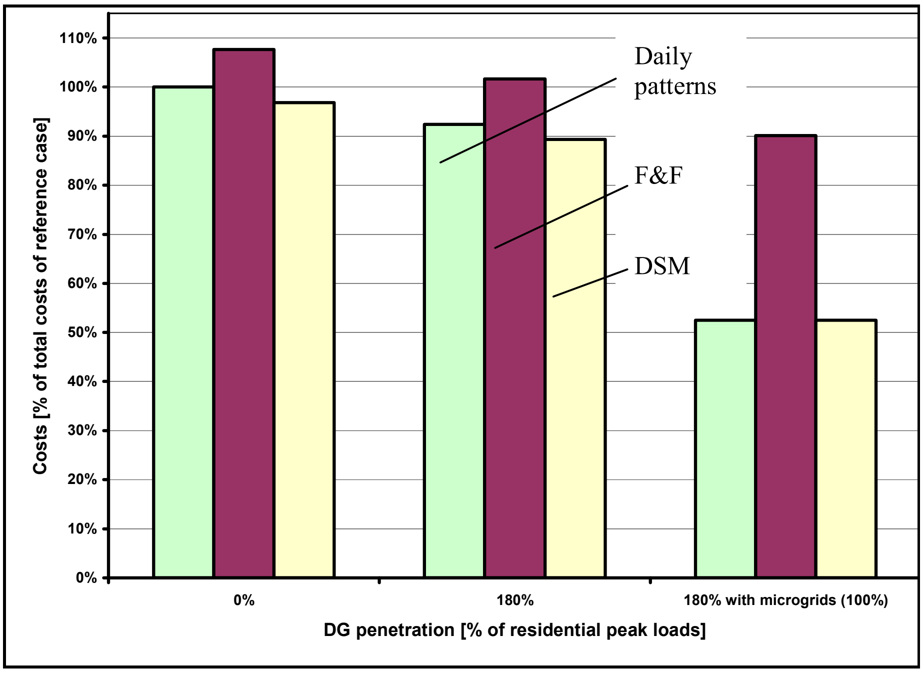


Figure 2.56. Comparison of total costs under different planning strategies

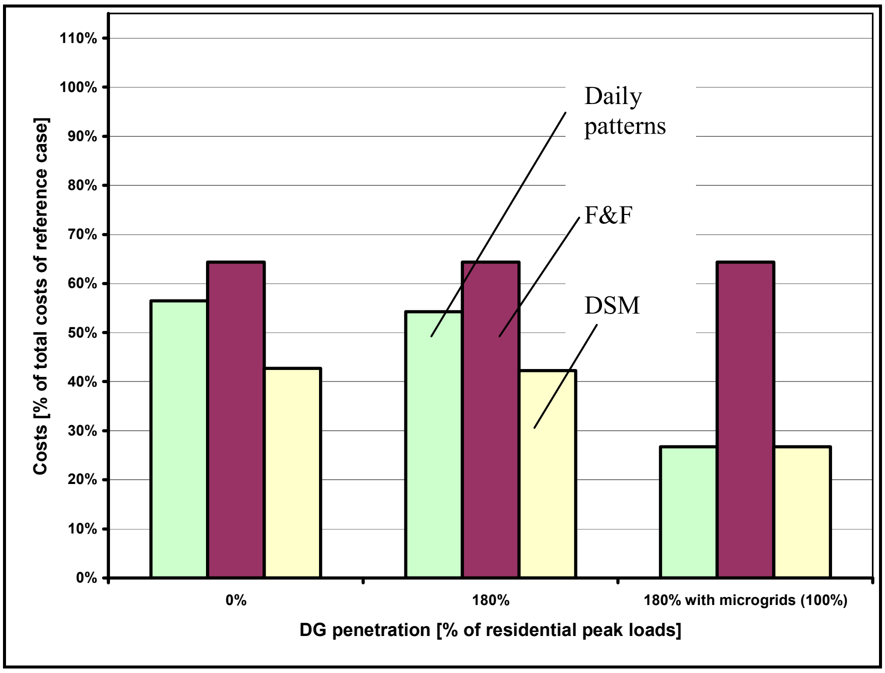


Figure 2.57. Comparison of investment costs under different planning strategies

It is worth noticing that in the presence of completely autonomous Microgrid operation, load shedding actions are never necessary even in emergency conditions, so investment costs and losses are the same as in the case of planning with daily profiles (the resultant optimal network configuration is identical).

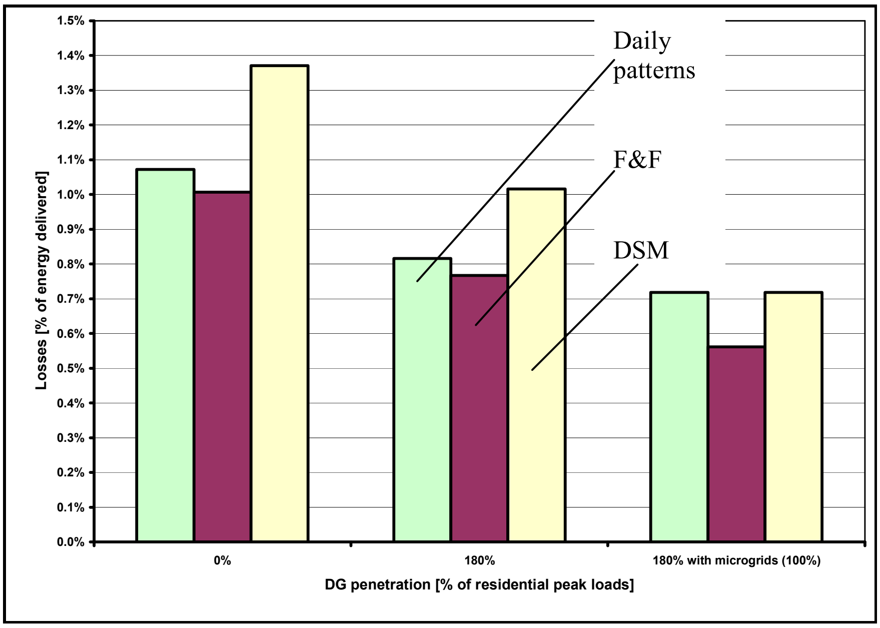


Figure 2.58. Comparison of energy losses under different planning strategies

2.10.5 Conclusions on the Italian network analyses

This Section has illustrated an analysis of the impact of DG and Microgrids on investments in electricity distribution infrastructures conducted on a typical Italian MV network, by making use of a software tool for optimal planning developed by ERSE for research purposes. The effect on network upgrade costs and losses of an increasing degree of penetration of PV generators in residential areas have been analyzed.

Different planning strategies have been adopted, namely: a) probabilistic, with load and generation hourly profiles; b) conventional "fit & forget" (worst case); c) considering active management options at a design stage. The comparison has been based on different parameters, namely, investment costs for network upgrading, cost of losses, energy losses, and voltage profiles.

The conventional "fit & forget" planning approach, based on a worst case scenario, leads to higher investment costs, due to the oversizing of lines and transformers. On the other hand, when the presence of DG is correctly taken into account at a design stage, benefits can be obtained, at least until a certain degree of penetration, in terms of reduction in investment costs for network upgrading – required to face load growth – and in cost of losses. If the possibility to resort to active management options is considered during the planning process, a further reduction in investment costs can be observed. However, the higher exploitation of existing network asset causes an increase in energy losses. These findings are completely in line with the findings by Imperial College for Northern and Central European networks with different types of DG, which highlights the generality of the results reached from different studies.

Finally, the effect of the integration, at the LV level, of loads, generators and storage in the form of completely autonomous Microgrids has been considered, resulting in zero active and reactive power flows at the MV/LV substation transformer. This configuration leads to a further reduction in network upgrading costs and electricity losses.

As a further final general comment, it is crucial to underline that active management options and Microgrid operation must be considered at the planning stage in order to take full advantage of their benefits for network development.

2.11 Impact on Microgrids on network replacement scenarios through generic distribution system fractal model

This Section shows some of the work carried out by Imperial College, detailed in Annex H2.C, for optimal *greenfield* distribution network replacement scenario analysis in the presence of Microgrids.

2.11.1 Multi-voltage fractal model, LCC network design criteria and value of DG

As widely described in Deliverable DH1 [3], Imperial has developed a specific methodology to assess the impact and the potential value of Microgrids on distribution network design strategies (*greenfield design*). The model is based on fractal algorithms that generate generic distribution networks mimicking realistic consumer settlements and network paths, thus enabling to get deeper insights on actual network topological characteristics with respect to other simplified geometric models [15].

In order to evaluate system-level network replacement strategies, different voltage levels are modelled for distribution systems, namely, LV, MV and HV. Indeed, only by modelling the whole distribution cost chain is possible to fully capture the benefits associated to Microgrids, even if operating at the LV level only.

Optimal economic design strategy (based on minimum Life Cycle Cost - LCC) [16] is carried out as a benchmark design to be adopted in the future, which is consistent with the information on replacement strategies received from the partners. This design approach trades off operational cost (mainly due to losses, with minor contribution from maintenance, above all in rural overhead lines) against cost of investment, so that key network performance indicators are the network costs (infrastructure and loss-related) with relevant breakdown.

The value of DG in Microgrids is then assessed by comparing the relevant output metrics (mainly cost of investment and cost of losses) with and without microgeneration. For these purposes, the network design exercise has been carried out for a base case with no DG, and for a number of different penetration cases in which the presence of DG is taken into account when evaluating the upstream flows at MV.

In terms of circuit design, based on the LCC model illustrated above, it can be expected that the impact of DG will be such that potential reduced flows in MV and HV network branches (the *net* flows in the branches are the driver for LCC circuit design) might imply deployment of smaller circuits due to lower cost of losses. However, smaller circuits might also mean higher losses at the design stage with respect to the case without DG (where higher losses would lead to larger circuits). The presence of reduced flows owning to DG is not considered to size laterals and feeders at LV. In fact, while it is realistic to assume a certain degree of diversity provided by a large number of small-scale units aggregated at LV when it comes to sizing the upper voltage levels, sizing also the LV branches might be unrealistic. As a result, the value of DG at LV will be purely from the value of losses reduction contributed by DG.

For the sake of simplicity full availability is considered here for the DG units, in order to have an estimate of the potential effects of DG for different penetration levels and control strategies. This somehow leads to an upper boundary of the potential contribution of DG for network capacity support at upper voltage levels, while actual benefits in terms of capacity support might be slightly less, as also discussed below.

Large-scale typical urban areas and rural areas in the UK have been considered for exemplificative purposes of system level analyses. However, although the specific numerical results are of course case-specific, the general outputs and considerations stemming from the analysis are expected to be applicable to most networks and cases across Europe.

2.11.2 DG technologies and control strategies for network replacement analysis

Different technologies are considered for the analysis, namely, CHP and PV, and are assumed to be only connected at LV level. More specifically:

- Heat following for uncontrolled CHP whereby CHP generator follows the thermal load and electricity is produced according to its co-generation ratio;
- Electricity following for 100% CHP whereby CHP generator follows the local electrical load and heat is produced according to its co-generation ratio;
- Uncontrolled PV whereby electricity is produced as a result of solar power.

For CHP systems, the *controllability* issue is addressed here by assuming that the CHP unit is running under electricity following strategy as opposed to the classical "uncontrolled" strategy in which heat demand is followed, corresponding to intermittent generation from a network outlook. Indeed, it can be expected that by controlling DG in order to follow the electrical load the negative network impact will be minimized and on the contrary network benefits will be maximized. In this way, "impact boundaries" can be drawn by assessing the impact for the two limit control strategies, providing indications on the additional potential value of controlling DG within Microgrids. Although these boundaries do not envelope the maximum benefits that controllability can bring, which would be related to optimize specific objective function and each single case (see WPG for these specific types of analyses), the approach followed enables to get insights from a system-level strategic perspective on the value of different operability configurations and of increasing the correlation between local supply and demand, which has proven to be one of the main drivers for benefits.

In the analyses considered in the sequel, penetration level is defined as number of LV customers equipped with DG. Therefore, 100% penetration means all the customers have a DG unit installed at their premises. Typical electrical and thermal load patterns have been used to populate the networks with different types and number of realistic consumers, whose details are reported in Annex H2.C.

2.11.3 Urban network design

Typical UK urban load density has been used to populate the relevant network characteristics, as shown in Table 2.3.

Table 2.3. Urban network characteristics used in the case study.

Urban network characteristic	LV	MV
Peak demand [MVA]	5	370
Load density [MVA/km2]	5	3.7
Number of 11/0.4kV subst.	25	1,800
Number of 33/11kV subst.	-	12
Network area [km2]	1	100
Network length [km]	27	322
Number of LV consumers	2,000	150,000

Figure 2.59 shows the overall value of DG (capitalized value of losses plus investment, given in £/year per kW of network peak demand and based on 30 years network life and 7% discount rate) for different penetration levels of PV connected at LV system, with breakdown of value per voltage level. Similarly, Figure 2.60 shows the value of DG in the case of CHP systems (in both uncontrolled and controlled cases). As mentioned above, the value of DG has been calculated as difference between base case (network designed without DG) and the DG case.

It can be easily observed that controlled CHP provides the highest value for avoided network cost with least network impact, since perfect match is achieved between local demand and supply, minimizing the flows required from the upper network as well as possible counter-flows due to load/generation un-correlation and then exporting energy. However, it has to be noticed that even when perfect local match (full controllability) occurs, it is not possible to decrease the network below certain thresholds (that also depend on the penetration levels). In fact, the circuits need to be able to stand the relevant short-circuit currents, which leads to install minimum circuit size. In addition, for at MV and HV voltage levels the circuits are typically doubled due to security constraints and need for guaranteeing that enough capacity is available for network reconfiguration in the presence of downstream faults.

As for the uncontrolled CHP, the value of DG is still quite substantial owing to the good correlation between load and generation. As expected, the highly uncorrelated PV generation to load profile (peak production occurs in summer daytime, while consumption in the UK is prevailing in winter evenings) results in the lowest network value. For Southern countries, PV could instead provide suitable network support, as for instance exemplified in the Italian distribution network analyses reported in Section 2.10.

The potential cost contribution of DG for infrastructure replacement is summarized in Table 2.4 with respect to the base case network cost with no DG. It can be appreciated that potentially up to one-third of network cost can be avoided for 100% controllable

CHP scenario with 100% of DG penetration. However, also uncontrolled CHP can give a substantial contribution owing to relatively good electricity and heat demand correlation, which translates into good generation and demand correlation even for the heat following strategy. On the other hand, the extent of cost contribution from PV is more limited, and it is mostly due to cost reduction, which in turn drives towards smaller circuits according to the minimum LCC methodology adopted. However, this effect is relatively small.

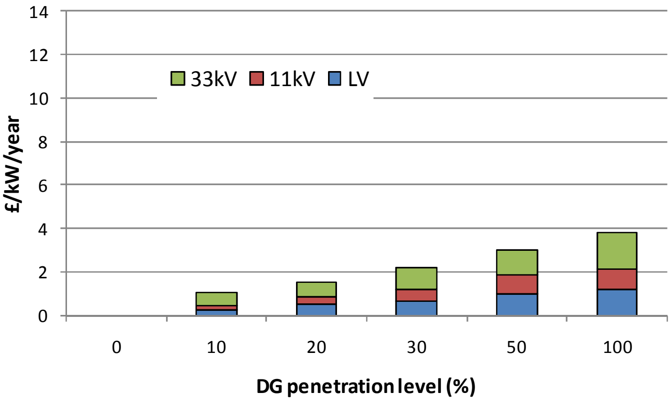


Figure 2.59. Network value of DG for PV in UK urban networks.

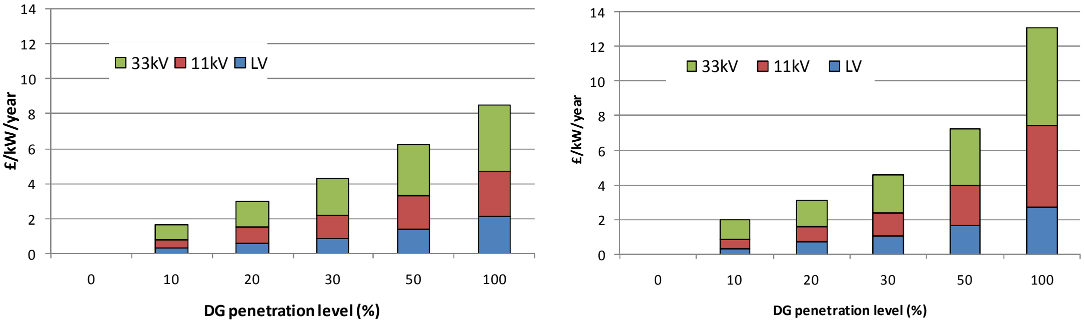


Figure 2.60. Network value of DG for uncontrolled (left) and 100% controlled (right) CHP in urban networks.

Table 2.4. Overall value of DG (for LV, MV and HV) in percentage with respect to the base case (no DG) urban network cost.

	DG penetration levels (%)					
Scenarios	0	10	20	30	50	100
PV	0.0	2.8	4.2	6.1	8.4	10.6
Uncontrolled CHP	0.0	4.7	8.3	12.0	17.3	23.7
Controlled CHP	0.0	5.5	8.7	12.7	20.1	**36.3**

While the previous analyses were based on the value of DG per kW of peak load, Figure 2.61 shows the capitalized value of DG per kW of DG installed capacity across the considered network life. The relevant figures could be for instance used to estimate possible contributions for DG owners. In this case, it is very interesting to observe that DG provides the highest value at the lowest penetration level (10%) and decreases with higher penetrations levels, with CHP of course being more valuable than PV, as expected from the above considerations. Also, the value of controllability for CHP varies non-linearly and non-monotonically across penetration levels, with higher values observable for lower and higher installed capacity range. This is a consequence of the complex dynamics occurring between local generation/demand and network flows. In fact, for very low penetration levels the DG contribution to decrease network flows and losses is immediately apparent, and the value of increasing this contribution by controlling the generation flows is quite high when weighed with respect to the installed capacity. For increasing penetration, the value tend to saturate, also considering that, besides network flows, other drivers such as short-circuit requirements influence the network design. As consequence, the marginal value per unit of installed capacity decreases, but the value of controllability slightly increases and becomes substantial (about 50 £/kW$_{DG}$) for 100% penetration of CHP, when more counter-flows might occur. However, it must also be taken into account that only discrete capacities are available when selecting the relevant pieces of equipment, and this may play a significant role above all when it comes to transformer selection at voltage levels higher than LV. In fact, in this case relatively few capacity sizes are available, so that some sort of jump in value might be observed if the incremental flows from additional DG are such as to trigger the installation of the lower adjacent size. On the other hand, this effect is not really remarkable at LV, where plenty of capacities are available and thus it is easier to approximate a continuous value function. If discrete equipment selection may generate non-linear trends, on the other hand it is important to account for that in order to provide more realistic results with respect to an ideal continuous selection.

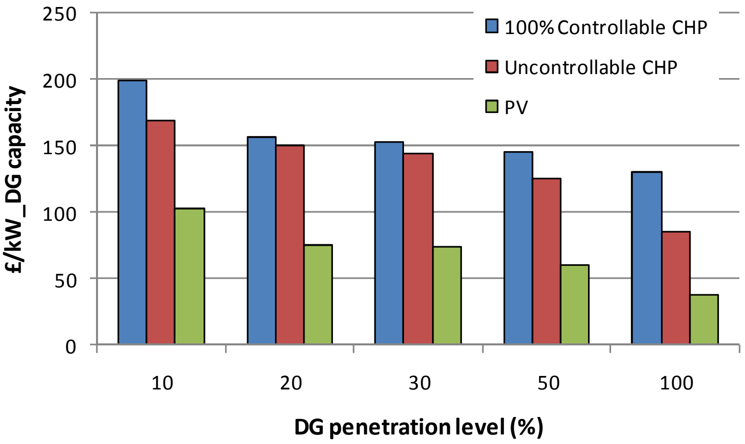


Figure 2.61. Total network value of DG in urban areas per installed DG capacity.

Figure 2.62 and Figure 2.63 shows the total network losses for the considered scenarios for PV and CHP, respectively. It can be observed that the higher is the correlation between DG generation and demand profile, the greater is the network losses reduction. In particular, the losses decrease is substantial at LV, where the great majority of losses within the distribution system occur. Relative losses reduction with respect to the base case can be as high as 50% when uncontrolled CHP is used for the 100% penetration level, and in the same condition controllability can further decrease losses by an additional 15%. Hence, total distribution losses may pass from about 3.7% without DG to as little as 1.4% in the case of controlled CHP for all LV customers. On the other hand, it is very interesting to observe the effects of PV generation. For low penetration levels, the contribution to losses reduction is similar to the one from CHP. However, this reduction starts to saturate at higher PV penetrations (>50%), as apparent from Figure 2.62, whereby there reverse flows occur (PV production becomes substantial at times of low demand in the central hours of summer days).

Further analyses relevant to cost breakdown per equipment and voltage levels are reported in Annex H2.C.

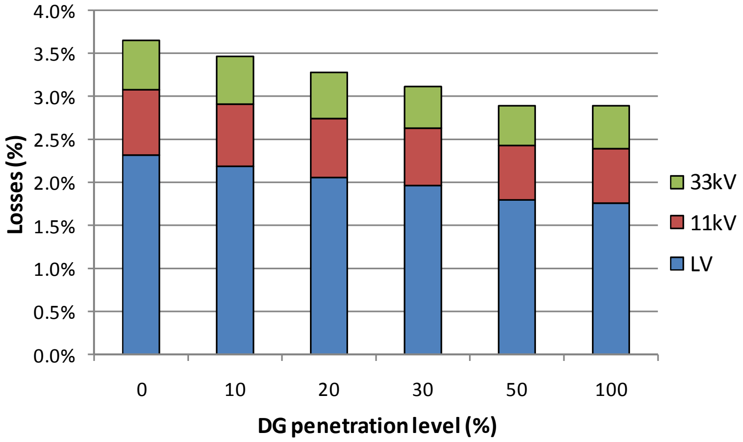


Figure 2.62. Total network losses in urban areas for PV

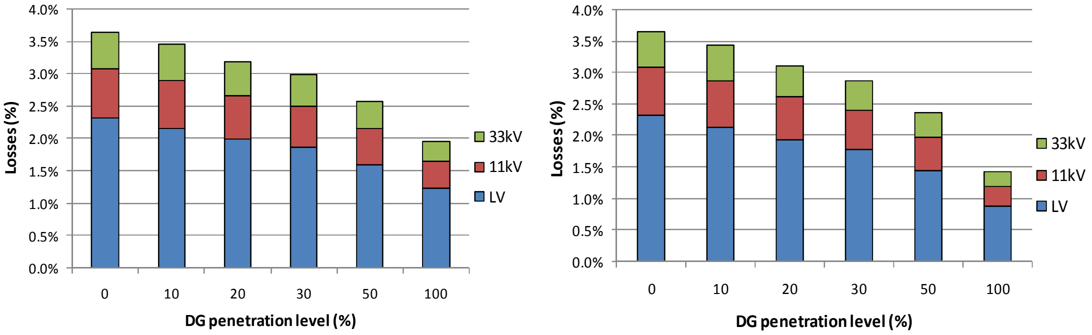


Figure 2.63. Total network losses in urban areas for uncontrolled (left) and 100% controlled (right) CHP

2.11.4 Rural network design

In order to have a full picture of the potential of Microgrids for network design contribution, studies on typical rural networks have been carried out in addition to the above urban analyses. The full set of studies performed for rural areas, analogous to the urban studies, is reported in Annex H2.C.

2.11.5 Losses result comparison with other studies

The impact of RES and DG especially micro generation (micro-CHP and PV) had also been previously studied through the UK GDS model in [17], which is recalled here for the sake of comparison. In that case, two different network characteristics, rural and urban were used, again taking into account peak and off-peak demand conditions and temporal variation (hourly and seasonal) of loads and DG output for different penetration levels of DG. Characteristic simplified profiles of micro-CHP and PV were used. The results of the studies are summarised in Figure 2.64 for rural areas and Figure 2.65 for urban areas.

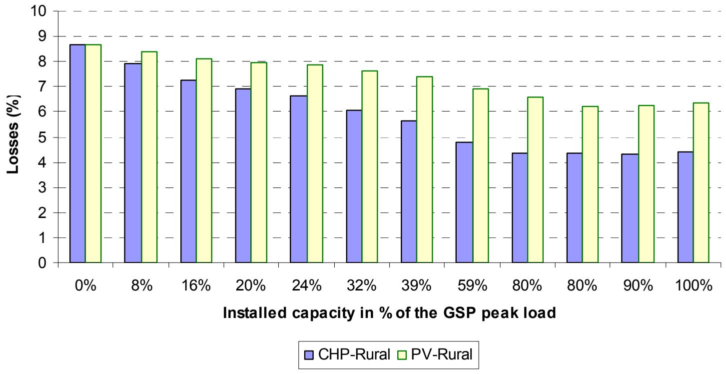


Figure 2.64. Contribution of micro-CHP and PV on the reduction in distribution network losses in rural areas in Northern European characteristic systems.

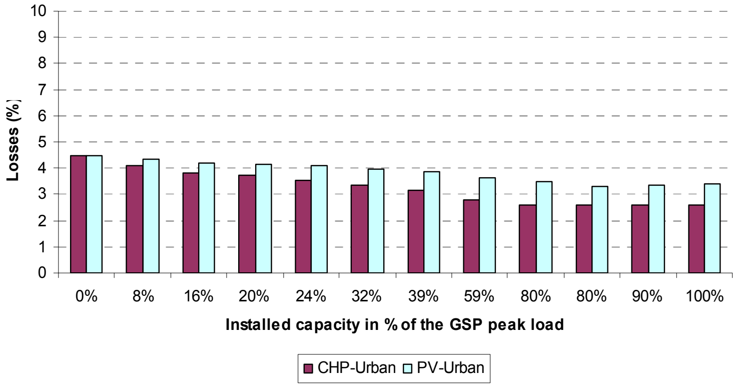


Figure 2.65. Contribution of micro-CHP and PV on the reduction in distribution network losses in urban areas in Northern European characteristic systems.

Losses are given in percentage of annual energy consumption. In the UK, the average distribution losses are about 7% with losses in rural networks significantly higher (mostly doubled) than losses in urban (city) areas. This can be understood since customers in rural areas are more clustered and connected via longer and smaller conductors compared with customers in town and cities. Thus, the effect of deploying micro-CHP and PV is more apparent in rural systems. The level of losses can be reduced by 41% from 8.5% to 5% of annual energy consumption by micro-CHP with total installed capacity of 50% of the total Grid Supply Point (GSP) peak load. In urban areas, the same capacity of micro-CHP only reduces the level of losses from 4.5% to 3% (33% reduction). Application of PV also shows similar trends but with significantly less impact in magnitude; in fact, with the same installed capacity (50% of peak demand), the reduction of losses is about 1.5%. This is less than half of the benefits obtained by micro-CHP. Given that the peak output of PV is not correlated with peak demand especially in the UK, PV contribution to loss reduction will not be as significant as micro-CHP.

It is therefore interesting to notice how the analyses run for future network development through the fractal model are consistent with the impact assessment analyses run with the GDS system. However, besides that, it is also interesting to notice how in the fractal expansion analyses the figures found for losses were quite lower than the actual ones, above all for rural areas (see Annex H2.C). This is due to the LCC methodology used for network design, which, by explicitly taking into account the cost of losses, implicitly leads to set up an energy-efficient network, benchmark for future power systems.

2.11.6 Concluding remarks on the fractal network replacement assessment

7

The studies carried out with the fractal model for greenfield network design show that correlation between load and generation is a key factor for network development contribution of DG and the relevant value of control micro-generation within Microgrids, confirming the impact assessment studies run above for different European countries. In this light, uncontrolled CHP could potentially provide network support owing to good correlation, with a substantial value brought by DG in both urban and rural areas. Up to one-third of network cost can be avoided for 100% controllable CHP (corresponding to an annual network cost of about 11 £/kW), with the maximum value of controllability in the order of 50 £/kW$_{DG}$ in urban areas for 100% penetration level and 30 £/kW$_{DG}$ in rural areas for penetration higher than 30% (see Annex H2.C for rural-related assessment). On the other hand, PV has poor correlation with the load in the UK systems analysed, and can only provide up to 10% of network avoided cost, mostly in terms of losses. The network infrastructure savings due to reduced power flows is substantial at MV, with prevailing influence on transformers in urban areas and overhead lines in rural areas. Equipment capacity saving is also significant at higher level of penetration, where the smaller number of pieces of equipment available may induce form of nonlinearities in the DG value for different penetration levels, though.

2.12 Fractal network-based analysis of economic and environmental impact of micro-CHP systems in Microgrids

This Section reports the main findings of the work carried out by Imperial College, detailed in Annex H2.C, about comprehensive network and environmental benefits for distributed CHP (DCHP) systems operated within Microgrids according to different control strategies, and of the relevant impact of controllability actions. This is fundamental to identify all the costs and benefits from DER not only in terms of electrical networks but for the overall energy system chain.

2.12.1 Network, environmental and DG modelling

Potential costs and benefits in terms of network impact from DCHP operated within Microgrids are calculated on the basis of a reference network whose topology and circuit sizing is generated through the fractal model and the LCC methodology described in the previous Section. Again, a typical UK urban network model is specifically used for the analysis, but the methodology could be applied to more general situations for system-wide assessments.

The energy performance of CHP prime movers are represented by their electrical efficiency and thermal efficiency. In addition, the *cogeneration ratio*, ratio of heat to electricity output as well as of thermal to electrical efficiency, is used to characterise the DG behaviour. Details on the modelling can be found in Deliverable DH1 [3].

Different penetration levels are analysed, indicated with the index *p*, defined as the relative number of customers with a CHP unit out of the overall LV customers. In addition, as in the previous Section two control strategies for DCHP have been defined here, namely, *Heat Following (HF)* and *Electricity Following (EF)*. As mentioned above, from the electrical outlook heat following mode may be considered as *uncontrolled* or intermittent generation, whereby cogeneration benefits are maximised. On the other hand, if the CHP generator follows the local electrical load, heat is produced accordingly (regardless of the actual thermal load), as resulting from the characteristics cogeneration ratio. In this case, an auxiliary boiler is assumed to be put in operation to supply the thermal load if the thermal production is not sufficient (no storage is modelled here). On the other hand, if the heat cogenerated is higher than the actual local thermal demand, heat is wasted. Therefore, this strategy brings smaller environmental benefits relative to the thermal load following. Environmental benefits are defined according to the *PES* (primary energy saving) and *CO2ER* (CO_2 emission reduction) indicators introduced in Deliverable DH1 and detailed in Annex H2.C.

For each penetration level *p* of DCHP, *controllability* within Microgrids is addressed by changing the number of units operated following the local electrical load rather than the thermal one (assumed to be the base case). This is indicated through the index c_p, pointing out the ratio of electricity-driven CHP units with respect to overall ones (the remaining units are supposed to operate with classical thermal following).

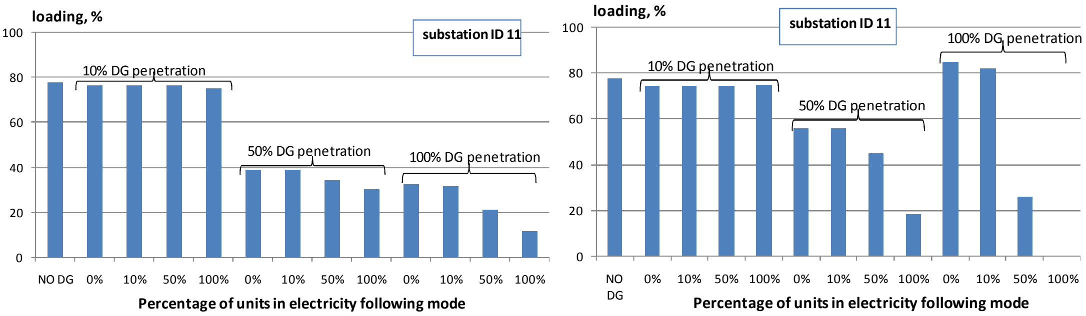
Network benefits of DG are based on identifying the investment deferral benefits and losses change owing to DCHP generation for different scenarios with respect to a bas case without DG. Hence, the main difference with the analyses run in the above Section is that here no network design is carried out, but the *impact* on a (reference) network is assessed.

2.12.2Generation scenarios and analyses

Starting from the network and demand characteristics detailed in Annex H2.C, two generation mixes (also detailed in the Annex) have been considered, which lead to a number of scenarios obtained by changing the DG penetration and controllability indices. In the *generation mix 1*, terrace houses equipped with DCHP can in principle cover both electricity and heat peak (if the two peaks occurred simultaneously); this is line with currently envisaged applications of micro-CHP systems mainly aimed at substituting residential boilers. On the other hand, regardless of the control strategy adopted, flat buildings equipped with the MT1 in any case needs support from the grid to cover the electrical demand and from auxiliary boilers to cover the heat demand. Again, this sizing approach is in line with typical design strategies for relatively larger CHP systems aimed at covering a certain part of the electrical/thermal load to maximize the plant profitability. In the *generation mix 2*, again terrace houses with DCHP can potentially cover both electricity and heat peak, with a major difference relative to the previous case, namely, that electricity can be exported to the grid owing to the larger electrical capacity of the ICE unit. Similarly, flat buildings equipped with the MT2 will be able to export electricity when following the heat demand. It is also important to highlight that the overall DG electric capacity installed in *generation mix 2* is such that all LV networks considered can in principle operate isolated from the MV network as energy autonomous Microgrids, while isolated operation for *generation mix 1* could occur only through resorting to load control actions.

2.12.3 Synthesis of the network deferral results

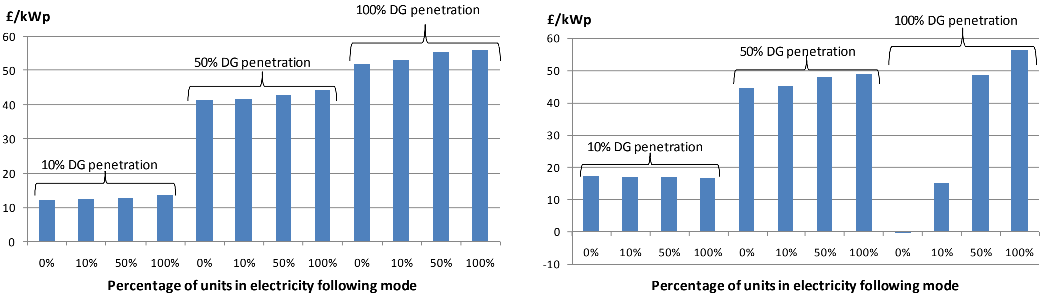
A number of nonlinearities arise in the operation of DCHP systems in different penetration and controllability scenarios, which highlight the complexity of the concepts studied. In this respect, Figure 2.66 illustrates some typical nonlinearity that may characterize the peak loading analysis (relevant to investment deferral benefits) for a representative case of 100 kVA transformer. In particular, it can be seen how for generation mix 1 while moving from p = 10% to p = 50% the loading level halves, with negligible impact of controllability for 10% penetration and relatively small for 50% penetration. On the other hand, increasing the penetration level to p = 100% does not change substantially the substation peak loading level, due to some sort of saturation in the correlation between generation and loads. However, the loading level further decreases when the share of generation units in electricity following mode increases. Contrarily, the higher installed electrical capacity in generation mix 2 is such that counter-flows occur for high penetration levels, leading to even higher loading level than in the base case (without DG) for p=0 and all CHP units in heat following mode. In this case, the effects of controllability to mitigate counter-flows are apparent, with the LV network that can operate isolated as an autonomous Microgrid for c_p=100% (transformer loading level equal to zero in Figure 2.66 (b)).



a) Generation mix 1 b) Generation mix 2

Figure 2.66. Zoom-out of substation maximum loading profile for a 100 kWe unit.

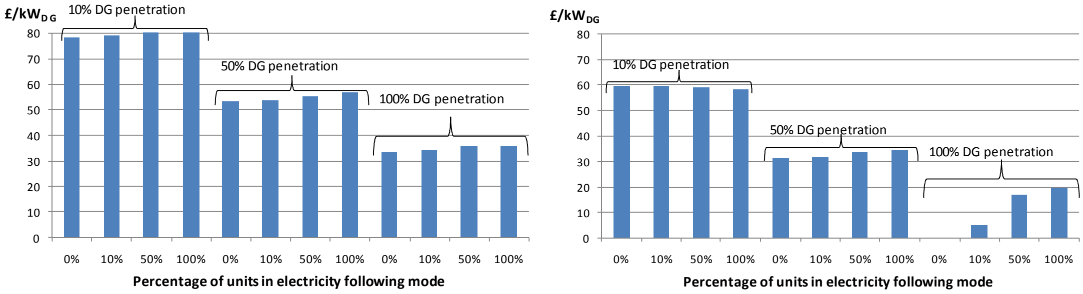
The analysis regarding the substation maximum loading level directly translates into ability of DG to defer investment, as opposed to potential negative effects of anticipating investment. A synthetic economic view on the effects of penetration and controllability levels of DG is provided in Figure 2.67 that shows the potential economic value (normalized to the network peak load) of network capacity release for the overall network. For generation mix 1, Figure 2.67(a) confirms that there is some sort of saturation effect in terms of network deferral value while increasing p, mainly due to the generation/load correlation. In all cases, controllability can increase the economic value of the network asset. Again, it is even more interesting to analyse what happens for generation mix 2. In fact, in this case for low penetration (p = 10%) the value is about 50% higher than for generation mix 1, owing to local generation/load balance. On the other hand, there are only marginal benefits from generation mix 2 relative to generation mix 1 for p = 50%, due to the increasing uncorrelated energy between generation and load. The situation is exacerbated for large DG penetration (p = 100%) of generation mix 2, for which no economic value arise at all due to uncorrelated flows as exemplified in Figure 2.67(b) unless DG is operated under electricity following mode. However, even in this latter case the value is less than from generation mix 1, apart from marginal benefits in the extreme case with p = 100% and c_p = 100% (isolated energy autonomous Microgrid operation).



a) Generation mix 1 b) Generation mix 2

Figure 2.67. Network overall *NPV* (normalised with respect to the network peak demand) of transformer capacity release.

In terms of network value brought by DCHP normalised with respect to DG installed capacity (potentially useful to formulate rewards for the prosumers), it can be appreciated how the specific value of DG decreases with the penetration level, that is, the marginal value of DG is a negative slope function with respect to the penetration level as shown in Figure 2.68. In fact, the benefits brought by local balancing are maximised when the DG production is relatively low (all produced electricity displaces peak flows), and decreases with an increase of (in part uncorrelated) production. For the same reason, the value for generation mix 1 is higher than for generation mix 2 by about 20 £/kW$_{DG}$ regardless of the control strategy for penetration level of 10% and 50%. The value is even higher for p = 100% when part of the units in generation mix 2 are run following the heat, for the reasons explained above.



a) Generation mix 1 b) Generation mix 2

Figure 2.68. Network overall *NPV* (normalised with respect to the DG installed electrical capacity) of transformer capacity release.

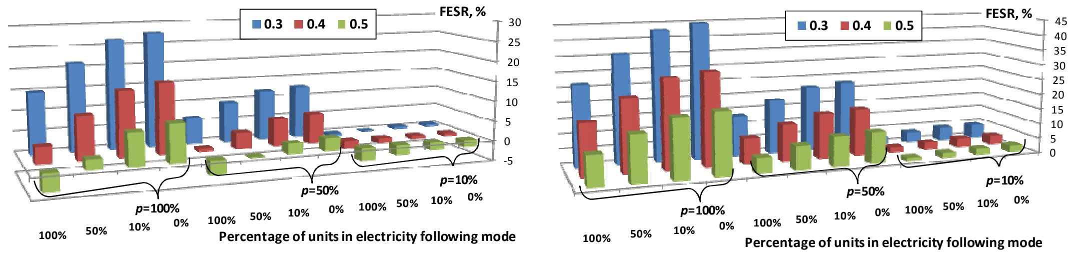
2.12.4Environmental performance

While the previous analyses have focused on network impact, Figure 2.69 and Figure 2.70 show the potential environmental benefits that DCHP systems can bring owing to cogeneration of electricity and heat in terms of energy saving and emission reduction for the overall network, respectively. Besides for different values of p and c_p, also different average power system electrical generation efficiencies and emission factors are considered as parameters, while for heat generation the base case refer to the thermal energy balances calculated in the case of no DG.

The environmental benefits increase with DG penetration, as expected since a higher share of overall generation is achieved through high efficiency combined production. This is also apparent from the comparison between generation mixes 1 and 2, with the latter bringing higher benefits in all cases owing to the higher overall electrical and thermal capacities installed. In addition, the benefits increase substantially if the comparison is carried out with respect to relatively lower efficiency and higher emission marginal plants. Typical electrical efficiency reference values for marginal plants can be in the order of 30÷35% (open cycle gas turbines and coal plants), with relevant emission factors in the order of 700÷800 g/kWh$_e$.

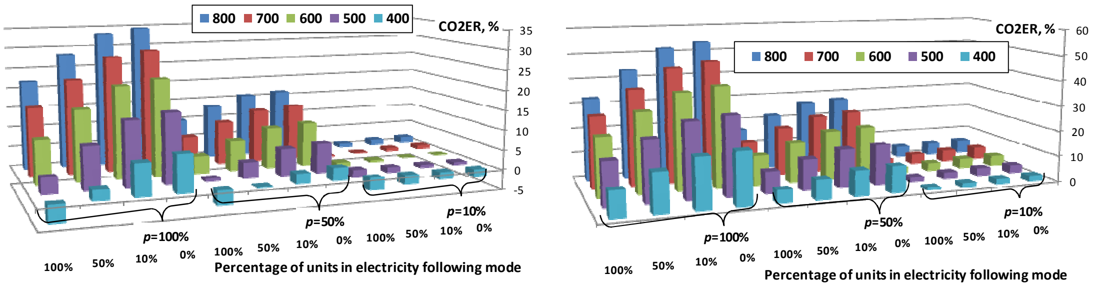
A further key point is that the environmental benefits are dramatically influenced by the control strategy, with heat following mode yielding much better performance with respect to electricity following mode. Again, this is due to the fact that the benefits of cogeneration are maximized when the heat load is followed, as the electrical network is available as a sink for excess production or as a source for covering demand in excess of generation. On the contrary, when electricity is followed, heat generation comes along and the non perfect correlation between electrical and thermal load may generate either heat in excess of the demand (to be wasted off) or insufficient to cover demand (so that auxiliary boiler production is needed). Either way, the benefits of cogeneration are decreased relative to the heat following strategy.

In order to get an idea of what the environmental benefits might mean in economic terms, a possible way is to transform the emission reduction into economic flows by costing the emissions, for instance based on the prevailing cost of emission trading scheme. This corresponds to internalize the external environmental effects according to the external cost framework discussed in Deliverable DH1 [3]. The results from such an exercise are reported in Figure 2.71 with reference to *generation mix 2*, based on a carbon cost of 20 £/ton$_{CO2}$, highlighting that the environmental benefits if properly internalized lead to substantial economic savings for the society (the environmental cost savings are normalized with respect to overall electric energy demand). In particular, for the largest penetration of CHP and marginal emission factor around 700 g/kWhe, the environmental cost savings are in the order of 14 £/MWhe for heat following CHP and drop to 8 £/MWhe for completely controlled CHP units (and autonomous operation of the LV Microgrids). These benefits should be taken into account too when analyzing the overall costs and benefits for the entire energy system owing to Microgrids development.



a) Generation mix 1 b) Generation mix 2

Figure 2.69. Cogeneration energy saving performance of the overall network (separate production parameters refer to average marginal plant electrical efficiency).



a) Generation mix 1 b) Generation mix 2

Figure 2.70. Cogeneration emission reduction performance of the overall network (separate production parameters refer to average marginal plant CO_2 emission factor, in g/kWh$_e$).

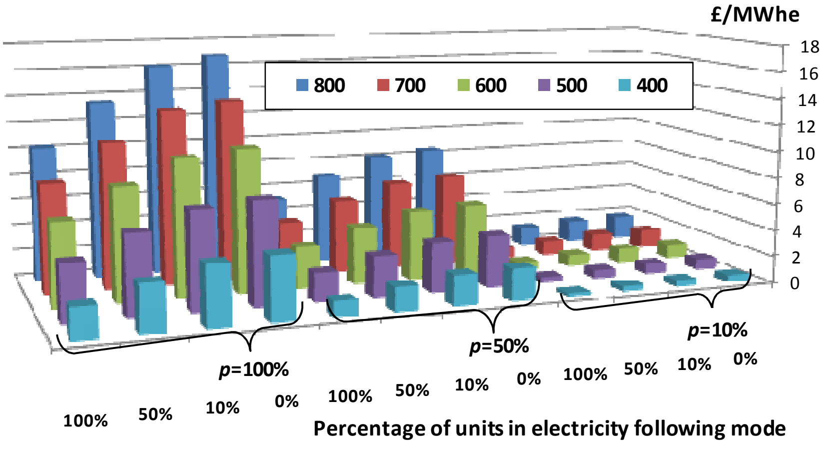


Figure 2.71. Cogeneration environmental-related potential economic savings for the overall network for *generation mix 2* (separate production parameters refer to average marginal plant electrical efficiency, cost of carbon equal to 20£/ton$_{CO2}$).

2.12.5 Concluding remarks on Distributed CHP studies

By taking into account electricity and heat aspects at the same time, more insights on the drivers for benefits have been gained in this Section, whose results are detailed in Annex H2.C. From the analyses it has emerged that the main driver for environmental benefits is the adoption of DCHP technologies with high electrical efficiency and run under heat following mode. On the other hand, if these technologies are sized to satisfy the heat demand, it is likely that substantial electricity exports to the grid occur. More specifically, the grid impact from the second generation mix could be much higher than from the first one when following the thermal load. In fact, owing to the lower cogeneration ratio, for a given unit of produced heat much more electricity is now produced. On the other hand, the possibility of controlling the units according to an electricity following strategy could lead to decrease the environmental benefits due to cogeneration (which corresponds to passing from an external cost benefits of about 14 £/MWhe to 8 £/MWhe, based on a carbon cost of 20 £/ton). For the generation mix 1, owing to the better match between production and demand cogeneration ratio, a better compromise between network and environmental benefits can be expected. In general, small penetrations are not going to lead to a substantial impact in any case, and benefits for both environmental and network criteria are likely to arise. For network deferral benefits, in particular, the value is in the order of 10÷15 £/kWp for small penetration and rises to about 40÷45 £/kWp for both micro-generation scenarios and 50% penetration level, with minor impact of controllability. However, for larger penetration levels problem might arise in terms of network impact, as apparent from generation mix 2, p=100% and c_p=0, needing network reinforcement (negative *NPV*) In this case, the adoption of controllability by reducing the electricity export can help mitigate the need for network reinforcement, although this would come at the above cost of environmental benefit loss. In any case, the upper level for network investment deferral is in the order of 55 £/kWp, which reflects the value of the transformer asset at LV. This value would further rise if the network deferral for the feeders at upper voltage levels were taken into account as well.

2.13 Considerations on network security contribution from DG and Microgrids

In the above studies, economics has been considered as the main driver for network investment analysis. In addition, in order to estimate to potential value of DG and Microgrids to network development, full availability of DG has been considered in the analysis. However, this is not the case in practical situations, when some DG units might not be available for network support and then security, and further considerations need to be carried out in terms of network design to guarantee security. Hence, although this aspect is primary focus of WPG, in the sequel few and mostly qualitative considerations are illustrated for the sake of completing the impact assessment of Microgrids on distribution network investment.

It has been shown [18] that DG could effectively deployed to contribute to network security, intended as provision of sufficient network resources to secure load in the event of network failure. A simple example is illustrated in Figure 2.72, where a DNO that traditionally ensures security of supply in a 33/11 kV demand group through network design (double circuit), ignoring the presence of the DG, needs to decide between a wired and a non-wired solution in the event of load growth. In particular, if no security contribution is allocated to DG, a new transformer needs to be added to maintain the same level of *n-1* security. Alternatively, the DNO could exploit the contribution of the generator. In this case, assuming an availability of the 30 MW generator equal to 60%, an overall security contribution of 18 MW could be recognised for network planning purposes, and the network reinforcement need is mitigated.

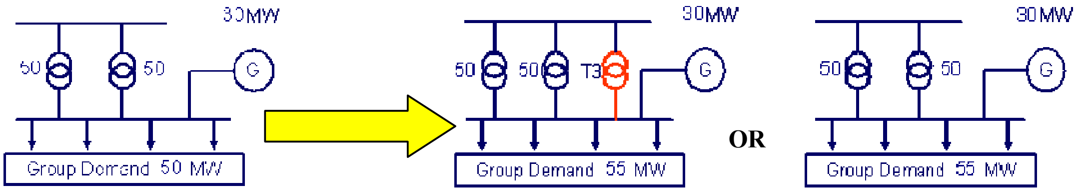


Figure 2.72. Wired and non-wired solutions to distribution network security of supply.

Recently a methodology for updating the previous network security standard [18] has been developed and adopted in the UK to take into consideration new distributed generation technologies. The methodology proposes a calculation of the capacity of a perfect circuit, which, when substituted for the DG, gives the same level of expected energy not supplied. The capacity of this ideal circuit is thus a measure of the capacity contribution of DG.

For the purposes of this work, it is interesting to know that the standard developed addresses non-intermittent (conventional generators) and intermittent (wind and hydro) generation technologies. In particular, for non intermittent generation availability of individual units and the number of units are key driving factors of the contribution that

DG can make. As expected, units with higher availabilities make larger contributions to security than units with lower availability, and a single unit makes less contribution than a capacity-equivalent group of multiple units. A further key point is that correlation between local generation and network demand represents the main driver for DG to provide security, besides benefits, as also discussed in the following Chapters for transmission and generation. Therefore, it can be expected that the capacity contribution of a large number of aggregated micro-generators within Microgrids can be quite substantial in those cases when generation and network peak demand are well correlated, as for instance for micro-CHP in the UK case. On the other hand, PV systems cannot contribute to network security in Northern European countries, but can certainly do so to a certain extent in Southern countries. These considerations are also in line with models that are based on probabilistic load flows to assess the capacity contribution of DG to network design [19], including the Italian case reported above, and with the detailed model developed by INESC for generation security of supply and illustrated in Annex H2.D.

With specific regard to the network design analyses run above, it can be expected that small scale CHP systems have availability in the order of 0.9, which corresponds to capacity contribution around 0.8 if more than 10 units are aggregated. These are the figures that can be expected for Microgrids operating with a large number of small CHP units, as in the examples shown in Section 2.11 for fractal model of system development. Therefore, also from a security standpoint it is reasonable to consider reduced flows at upper voltage level, also considering that in any case the LCC methodology for circuit sizing would lead to circuit utilization quite low (below 50%) and that short-circuit requirements would further increase this capacity, so that the final network design with reduced flows will be consistent in most cases with the DG capacity contribution calculated. In any case, the fractal analyses and the GDS analyses illustrated should be considered from a strategic standpoint in terms of giving general directions, while specific situations should be considered case by case. In this respect, the possibility of controlling micro-generators within Microgrids could lead to specific DG design aimed at providing some sort of reserve network contribution in those cases when micro-generation production were to fail. For these purposes, optimization models such as the ones developed in WPG for operational analyses could be adopted for network design analyses as well.

2.14 Final considerations on Microgrids impact on distribution network operation and development

In this Chapter, a number of models have been presented and relevant analyses have been run to assess the impact of micro-generation and Microgrids on electrical distribution network development. In particular, GDS-based studies have been conducted for northern and central European scenarios dominated by CHP systems, while specific studies have been run for Southern scenarios with prevailing PV generation. In addition, different analyses have conducted through generic distribution networks based on fractal topology generation in terms of current network impact assessment as well as network planning in the presence of DG and controllable sources.

Notwithstanding the differences in the models adopted, the input data, and the analyses run, some common points have emerged (through quantitative results) that are summarised below:

The contribution of microgeneration to decreasing upstream power flows leads to substantial potential decrease in losses and network utilisation, further allowing network investment deferral and subsequent economic savings for network operators.

The main driver for such benefits is the correlation between local generation and demand. Therefore, CHP systems can bring substantial benefits in northern scenarios to help accommodate growing loads without network reinforcements, while the potential of PV is restricted in this sense, due to the scarce correlation with peak load (typically occurring in winter). On the other hand, PV can bring network benefits in southern climates.

Benefits arise at low penetration levels of DG without significant drawbacks, while for higher penetration levels of DG losses can increase due to counter-flows, which could even lead to overtake circuit thermal ratings, above all if the load growth is not significant. In addition, voltage rise issues might arise as well in the presence of long (rural) feeders and high generation level uncorrelated with demand.

Strong networks with overrated circuits and relatively short feeders can accommodate DG without significant problems while operation benefits hold, although sometimes not significant. On the other hand, weak networks with smaller circuit capacities and longer feeders may exhibit problems that might be significantly mitigated by DG (when problem are demand-driven), whereas on the other hand local generation might exacerbate voltage rise issues calling for network upgrade.

For weak networks, therefore, at most penetration levels with respect to demand active management strategies of different forms (generation curtailment, load controllability, adoption of on-line tap changer coordinated with reactive power control, and so forth) can help put off network reinforcement and decrease the volume of asset to be reinforced.

However, active network operation, which generally also includes coordination between Microgrids and the upper voltage level when problems occur at MV, typically leads to higher operational (mainly losses-related) costs due to higher (and more efficient) deployment of the existing asset. The trade-off of additional losses and cost of implementation of (optimal) active management strategies against network upgrade cost needs to be thoroughly assessed, according to the models illustrated.

For network expansion purposes, a large number of micro-sources whose after-diversity production profile is well correlated with the network demand can contribute significantly to reduce the need for new asset with a good degree of reliability. Controlling generation in dispatchable sources such as micro-CHP to modulate their generation pattern to adapt to the electrical demand can bring further benefits. However, unless accepting a general decrease in generation overall efficiency, suitable storage systems should be coupled to micro-CHP to conserve the ability to meet the thermal demand of dwellings.

In terms of environmental benefits, the contribution of DG is significant owing to the clean technologies used, with the benefits due to clean energy production being at least one order of magnitude more than network benefits in terms of losses.

3. System-wide impact of Microgrids on transmission networks

This chapter discusses the main aspects relevant to the impact of Microgrids on transmission network development. More specifically, after discussing the economic and security rationales for transmission system design, specific analyses are run through a Cost Benefit Analysis (CBA) model developed by Imperial College to assess the impact of DG and generation controllability within Microgrids on transmission development. In addition, the value of controllable loads (namely, water heaters) aggregated within Microgrids is also analysed through a model developed by Imperial College for Demand Side Management (DSM) integration into system operation and development. The benefits from controllable loads are assessed in terms of congestion release and network capacity increase, also allowing a larger integration of intermittent large-scale renewable sources. The concepts developed have been exemplified through transmission analyses in a UK network test case.

3.1 Generalities: rationales for transmission investment and impact of Microgrids

As introduced in Deliverable DH1 [3], control of the output of despachable (and normally uncontrolled) DG systems together with responsive loads within Microgrids can be carried out to provide support to system operation and development. Besides the impacts on distribution networks discussed above, operation of Microgrids can influence the power system operation and development on the transmission level, namely, generation asset and transmission network. The extent to which MGs can influence transmission investment depends foremost on their penetration level, besides the specific generation characteristics of each technology and the correlation with demand, and the controllability level of DER sources, as explored below.

The primary function of transmission in a power system is to ensure efficient transport of electrical energy from generators to demand centres while maintaining required standards of security and quality of supply. The underlying philosophy of existing transmission networks was indeed centred on the requirement that transmission capacity should be sufficient to ensure that generators in remote areas are not unduly restricted from contributing to security of supply of local loads. With respect to system security, the impact of RES and DG on transmission requirement is a function on their ability to displace capacity of remote generators and their contribution to system security.
Methods described for instance in [20] for interconnected systems can be employed to assess the risk posed by transmission. The results show that the ratio of demand for transmission driven by security and the installed capacity of DG is quite linear to its capacity credit. In this respect, an illustrative example is shown in Figure 3.1, which has been obtained by computing the required transmission capacity for a remote equivalent generator with different capacity credit (see also Chapter 4 and Annex H2.D) to access a local load. More specifically, the values have been calculated by running capacity

adequacy studies based on a two bus-bar system, interconnected by finite transmission line. The capacity of the interconnector has been computed so that the risk posed by finite transmission capacity does not add up more than 5% to the overall system risk (largely determined by generation availability). In this way, the additional system risk posed by finite transmission is capped to 5% of the risk posed by finite generation capacity.

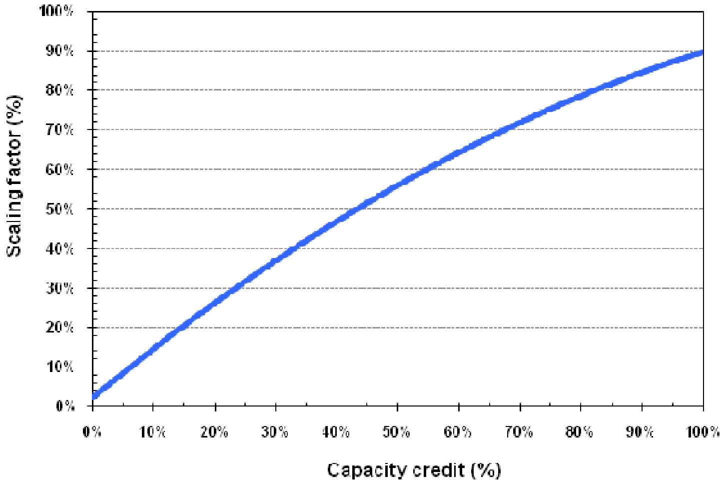


Figure 3.1. Ratio of demand for transmission and installed generating capacity as a function of its capacity credit.

Beside security issues, transmission is also built to allow access to merit but remote generators. As discussed in Deliverable DH1 [3], in the operational time scale this requires efficient dispatch of generation that minimises generation costs while maximising use of the existing transmission capacity. In the long term this requires that the system follows the path of least cost development that ensures efficient transmission investment. Therefore, putting together economic and security rationales, in Northern and Central countries uncontrolled DG with relatively high capacity credit such as micro-CHP [21] (see also Chapter 4 and Annex H2.D for exploration and quantification of this concept) is likely to remove out of merit local generation. Thus, it will not raise demand for new transmission but, in contrast, will release capacity of existing transmission so it can accommodate more load that can be served in the most cost effective way. On the other hand, in exporting areas increase in local generation will increase demand for transmission to allow more access to merit generation taking place in Microgrids. Optimal capacity of transmission in the presence of MG can therefore be optimised taking into account critical operating snapshots which cover the variability and intermittency of RES and DG technologies, their controllability level, and the interaction with given generation system. These aspects of transmission network operation and capacity planning are discussed below in the context of MG. In particular, the aim of the studies is to assess the impact of large scale microgrid deployment and operation on the transmission network especially on the development of transmission capacity (deferral of capacity reinforcement) and the impact of improving controllability of uncontrolled DG or loads on the system operation costs.

3.2 Methodology for assessment of optimal transmission investment considering the impact of Microgrids

3.2.1 Network operation synthesis

Network operation is concerned with management of network constraints in an efficient and cost effective manner to achieve minimum production costs. Management of constraints is primarily achieved through re-dispatch of generation. Regarding the potential of microgeneration for transmission constraint management, let us analyse for example the role of CHP and RES. In the case of CHP it might not be viable to constrain this generation off or on for purposes of relieving network constraints since heat demand would override the electrical network considerations especially in cases where storage is either limited or non existent as is presently often the case. As far as RES are concerned, renewable generation has a short run marginal cost of zero and therefore it is very costly to constrain off this type of generation diminishing the role of renewable sources in constraint management. Therefore, the scope for microgeneration contribution seems relatively limited. Nevertheless, it is worth analysing the potential value of controllable DG in microgrids for transmission network management purpose, even if it is only to a limited extent as discussed above. Apart from this, even under a scenario where the impact of DG in transmission constraint management is limited, it is still valuable for the TSO to have knowledge of the net impact of DG on the transmission system in real time. Better knowledge of variability of the DG output in real time would indeed enable the TSO to make more informed and therefore more cost effective arrangements for system reserve as well as constraint management, as better discussed below.

3.2.2 Transmission capacity planning

As mentioned above and in Deliverable DH1 [3], in the ideal case network capacity should be determined from an optimisation process that minimises the network investment and system operating costs. System operating costs largely consist of the cost of constraints, the cost of losses and the cost of unsupplied energy as dictated by particular security standards. The cost of constraints (or “out of merit order generation cost”) is in essence the cost associated with dispatching more expensive generation instead of cheaper generation due to network capacity constraints. Optimal transmission capacity is therefore obtained by minimising operating costs and transmission investment, that is, by balancing the transmission investment cost and the benefit derived from this investment by way of reduction in out of merit generation cost. As illustrated in Deliverable DH1, out of merit generation cost is inversely proportional to transmission capacity. Therefore, while it is in principle possible to run a system with zero congestion, this comes at high cost, which leads to the notion of optimal congestion. It has to be pointed out that this cost Benefit Analysis (CBA) approach steps beyond traditional security-driven approaches as typically envisaged in national grid codes. These would typically base transmission capacity calculation on the rationale of being able to meet peak demand with given installed capacity margin. However, this approach reflects conventional generation schemes, whereas since DG has different technologies (and, in particular, intermittent ones) the issue of the capacity that should be used in the determination of transmission capacity is critical. This is in turn primarily related to correlation of generation and demand when peak demand occurs, which does not necessarily correspond to peak generation or installed generation capacity. For example, in a Northern country with peak demand occurring in a winter evening, the output of PV based generation for purposes of transmission capacity planning should be zero given that at the time of the system peak the output of PV is likely to be zero. The output of DG and renewable generation at time of system peak demand is therefore central to determination of contribution for transmission capacity. This brings into focus the operating patterns of the DG and hence time of use of the transmission networks becomes critical.

3.2.3 Cost benefit transmission design in the presence of DG and Microgrids

On the above premises, it emerges how optimisation of network capacity according to the most economically efficient solution enables a better picture and quantification of the impact from non-conventional DG generators. Hence, the CBA model illustrated can be used to determine how much additional or deferred capacity would be driven through installation and operation of Microgrids. In particular, the potential value of *controllability* of microgrids (for instance, by controlling micro-CHP output) can be assessed.

Based on this concept, in terms of numerical analyses for illustrating the drivers and the impact of DG and MG on transmission infrastructures, a specific tool has been developed (see Deliverable DH1 [3] for details) by Imperial, which balances the cost of transmission constraints with the cost of increasing the transfer capability of transmission system, that is, transmission capacity increase can be justified only if the congestion relief benefits are higher than the capital investment costs. For each operating scenario (with and without Microgrids) the schedule of conventional and renewable generation outputs is determined by using economic dispatch calculation. Of course, the accuracy of the results depends on the accuracy of the modelling process and on the reliability of the input data. However, once reasonable assumptions are taken, the methodology allows an unbiased comparative assessment of alternative MG scenarios, which is the main objective of this work. In this outlook, since the methodology looks for the optimum in all the scenarios analysed (without microgrids, and with microgrids with different characteristics and penetration levels), comparison of the results lead to an unbiased evaluation of the actual impact of microgrids on the transmission infrastructure on a “like for like” basis.

3.3 *Case study application for the UK transmission system*

3.3.1 *Case study description*

A simple model of the UK transmission network (Figure 3.2) has been developed to exemplify the methodology formulated for assessment of the impact of Microgrids on network congestion management and transmission capacity.

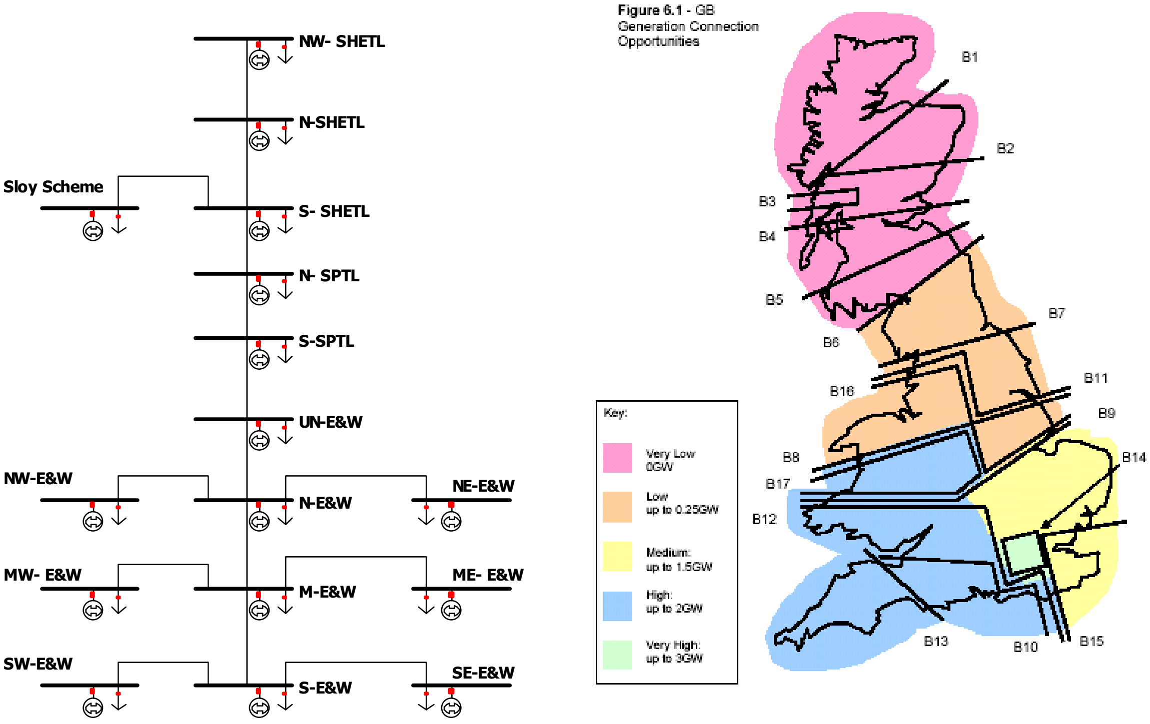


Figure 3.2. Simplified transmission model of the UK.

The studies use estimated generation and demand in 2010 as from the Great Britain Seven Year Statement (GB SYS) [22]. The total installed wind generation is considered equal to 12.1 GW. In addition to wind and other renewables, 10 GW of small and micro CHP is supposed to be installed, with a regional distribution estimated based on previous studies [23].

The resulting figures for each node used in the transmission model are summarised in

Table **3.1**.

Table 3.1. Estimated regional distribution of DG in 2010.

Region ID	Region	Proportion of CHP schemes (%)	Installed capacity (MWe)
NW-SHETL	Upper North	0.50	53
N-SHETL	North	0.50	53
SLOY	Sloy	1.00	107
S-SHETL	South	1.00	107
N-SPTL	North	1.00	107
S-SPTL	South	1.30	139
UN-E&W	Upper North	7.80	833
NW-E&W	North West	10.00	1068
NE-E&W	North East	8.60	919
MW-E&W	Midland West	12.80	1368
ME-E&W	Midland East	19.40	2073
S-E&W	South	8.50	908
SW-E&W	South West	4.70	502
SE-E&W	South East	16.50	1763

3.3.2 Value of wind and uncontrolled CHP

Since the studies aim to identify the long term value of Microgrids on transmission investment, it is assumed that transmission will be always built from zero capacity. Transmission and generation costs are evaluated for three case scenarios. In the first scenario, wind generation and CHP are excluded, and only conventional generators are taken into account. The first scenario thus represents a base case scenario and provides a reference for comparison purposes. In the second scenario, wind generation is added into the base case. In the third scenario, both wind and CHP are added into the base case. In this way, it is clearly possible to identify the impact and the drivers for benefit from different types of DG, namely, highly intermittent and potentially uncorrelated with the load (wind), and relatively more correlated (CHP that is supposed to operate under heat following mode). The results are summarised in Table 3.2 showing the cost/benefit of wind and CHP on transmission. The results show that the benefit of wind and CHP will be primarily in the reduction of generation cost.

Table 3.2. Estimated annual generation cost and transmission cost.

Scenario	Generation cost (B £/year)	Transmission cost (B £ p.a.)
I: Base	9.70	0.74
II: Base + Wind	8.60	0.78
III: Base + Wind + CHP	7.67	0.62

Compared to the base case (scenario I) the impact of wind (scenario II) is to increase the transmission cost by £40m per year. This is equivalent to capitalised value of £33.06/kW of wind, calculated as difference between the transmission cost in scenario I and scenario II, divided by total wind installed capacity (12.1 GW) and multiplied by ten in order to get the capitalised value. On the other hand, the simultaneous presence of wind and CHP (scenario III) compared to the base case (scenario I) reduces the transmission cost substantially, by £120m per year. This is equivalent to a capitalised value of £54.30/kW of total DG (wind plus CHP), calculated as the transmission cost of scenario I minus the transmission cost of scenario III divided by total DG installed capacity (22.1 GW) and multiplied by ten in order to get the capitalised value. Therefore, CHP close to demand has a tremendous impact on transmission investment, and this impact is even larger if we compare scenario II and scenario III, with the benefit of CHP being £160m per annum, translating to capitalised value of £160/kW of CHP. This value is equal to the transmission cost of scenario II minus the transmission cost of scenario III divided by the total CHP installed capacity (10.0 GW) and multiplied by ten in order to get the capitalised value. While the figures are rough estimates and should be viewed for exemplificative purposes and are case specific, the framework and methodology applied in making these assessments are however robust and can be used to evaluate alternative scenarios based on credible data inputs. In the specific case analysed, the indications from the study are that wind generation cannot displace effectively transmission capacity and may require, on the contrary, additional network investment. On the other hand, CHP systems relatively well correlated to loads may replace transmission capacity.

3.3.3 Value of CHP controllability within Microgrids

In the previous studies, although the installed capacity of CHP represented about 12% of total installed generating capacity, CHP generators were supposed to be uncontrolled, which reflects the current arrangements of DG nor being controlled nor dispatched by the TSO due to their small scale. However, as stems from the above analyses, the presence of a large number of CHP plants will certainly have an impact on transmission system power flows (as well as system balancing costs, as discussed in the next Chapter). The question arises as to whether controllability of DER within Microgrids, made visible to TSOs, could in the future bring benefits to transmission planning. In this respect, this Section illustrates how the results from the previous studies would be modified if CHP systems were controlled in such a way to optimise transmission flow managing and peak generation costs. For these studies, it is assumed that there is no constraint in distribution networks which hinder the use of DG for controlling flows in transmission network.

The studies were carried out assuming that the output profile of CHP can be optimised with a predefined degree of flexibility to reduce generation and transmission cost, and scenario analyses are run by increasing the number of controllable units (controllability level) with respect to the base case of heat-following (uncontrolled) output. It is important to note that the optimisation will modify the dispatch of CHP while preserving the amount of energy generated by DG on daily basis. This can be consistent with assuming, for instance, that storage systems are available to deliver in any case the required amount of heat to local users.

The overall results of the studies are shown in Table 3.3. These results demonstrate the value of DG controllability for various level of controllability, being namely comprised between 0 and £30/kW of CHP installed capacity. These values are relatively modest compared with the values obtained above from Table 3.2, but these results were expected since the network flows are still dominantly controlled using conventional generators.

Table 3.3. Estimated value of DG controllability for the case study system.

Controllability (%)	Reduction of transmission cost (M £/year)	Capitalised value of controllability (£/kW)	Reduction of generation cost (M £/year)	Capitalised value of controllability (£/kW)	Total value of DG controllability (£/kW)
0	0	0.00	0	0.00	0.00
10	6	6.36	1	1.00	7.37
20	16	15.68	-1	-1.23	14.45
40	25	25.04	0	-0.29	24.75
60	22	21.68	6	5.88	27.57
80	23	22.63	6	6.31	28.95
100	21	20.96	9	8.78	29.74

It is important to note that the capitalised value of controllability obtained in these studies depends on the assumption used in the studies with reference to generation and transmission cost. The marginal costs of generation used for this study are as follows: wind (zero marginal cost) and DG (£ 10/MWh), nuclear and hydro (£20/MWh), coal (£25/MWh), CCGT (£30/MWh), oil and other peak plants (£50/MWh). Conventional generators in Scotland are set to be cheaper by £2/MWh than the generators in England and the incremental transfer capacity cost is assumed to be 175 £/MW/km/year.

Apart from the absolute values (necessarily depending on the specific system topology and cost assumption for network asset and generation marginal cost), it is interesting to point out that the incremental reduction in demand of new transmission capacity and generation costs is not linear with the increase in number of controlled units, with a saturation showing up after about 60% controllability, as clearly shown by Figure 3.3.

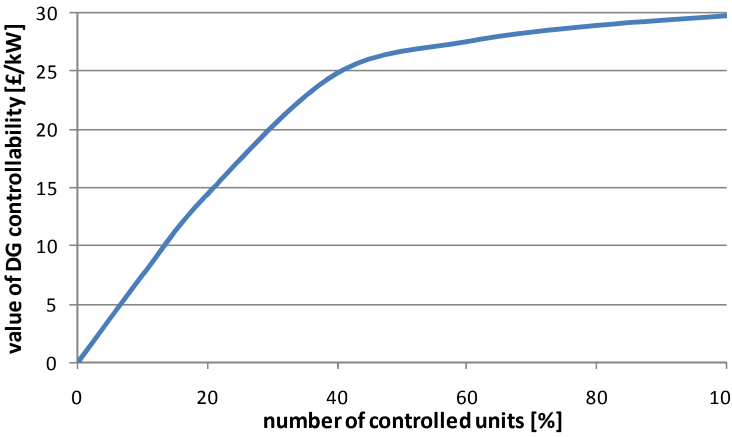


Figure 3.3. Value of microgrid-enabled micro-CHP controllability for transmission capacity release.

3.4 Utilisation of controllable loads in Microgrids for transmission congestion release

3.4.1 Generalities on controllable loads for transmission impact assessment

In the previous Sections we have explored how DG in Microgrids can impact at the transmission level. However, besides generation, controllable loads enabled by Microgrids could play a key role in transmission system development and congestion release (and thus potential investment deferral), and for larger deployment of intermittent sources. In addition, as better discussed in the next Chapter, controllable loads can bring substantial benefits in terms of system balancing, as already discussed in Deliverable DH1 [3], particularly in systems with significant contribution of intermittent and unpredictable Renewable Energy Sources (RES) in combination with inflexible conventional generation (nuclear, Carbon Capture and Storage - CCS).

A number of controllable loads could be adopted within Demand Side Management (DSM) schemes enabled by Microgrids, from water heaters and other household appliances to, more recently, electric vehicles. In particular, there are two general classes of loads whose characteristics lend themselves well for controllability purposes, namely:

- Loads whose time of use can be shifted or altered without changing the final outcomes, such as washing machines, dish washers and tumble dryers.
- Thermal loads, which rely on the availability of thermal storage systems or intrinsic storage characteristics as for instance providing by buildings. Water heaters, air conditioning systems and heat pumps belong to this kind of appliances.

A specific methodology [24] has been developed by Imperial in order to study the potential impact of DSM on transmission network management as well as, more specifically, of aggregated controllable loads enabled by Microgrids. In particular, the methodology enables to identify in which transmission points controllable loads should be placed, and to what extent. Hence, it is possible to identify the characteristics and the siting of those Microgrids that should aggregate controllable loads and perform the required DSM activities. Although not detailed here (for more details see for instance [25]), the developed also described the scheduling of the different appliances considered in the load control schemes, so that the Microgrid Central Controller (MGCC) could actually dispatch control signals. The benefits of controllable loads are established as the difference between the total costs of traditional network operation based solutions without DSM and the costs of the system that includes DSM technologies. As for the methodology for transmission planning in the presence of DG described above, in order to develop a network congestion management model the network operation costs associated with network congestion need to be taken into account.

3.4.2 Model of controllable loads for network congestion release

The controllable load model for network congestion release is built according to a two step optimization procedure. This is necessary in order to allow the quantification of the additional operation cost due to network congestion:

1. Economic dispatch of the available generation is performed in order to minimize the system operation cost based on the relevant generation marginal cost (€/MW) for each unit and for each time interval. The presence of wind generation is modeled through zero production cost in order to prioritize the usage of wind energy. The constraints considered are the generation/demand power-balance at every time step and the minimum and maximum limits on power output for each generator. Network constraints are ignored at this stage (network is assumed to be of infinite capacity) to obtain the total dispatch cost with single bus-bar system.
2. An Optimal Power Flow (OPF) is performed considering the actual network capacity limits and the output of the generators yielded from previous step. A DC model is used for the sake of simplicity (actually, transmission lines usually have high X/R ratio, so this assumption is justified in case of transmission networks), so that the formulation does not include losses. Whenever the generation schedule obtained in the previous algorithm step leads to violation of network constraints, the generation outputs are re-dispatched according to an objective function that minimizes the cost of these re-adjustments. Positive and negative adjustment costs are modeled for each generator, as usual in typical balancing mechanism markets.

It is clear that the goal of the algorithm is to minimize the additional operation cost caused by network constraints, and for this purpose controllable load (DSM) models are included in the OPF formulation. Available controllable loads can indeed lead to a lower value for the objective function, meaning less expensive network operation obtained by maximization of the utilization of the existing network capacity. When wind is taken into account, with its intermittent characteristics, overall cost reduction is accompanied and driven by reduction in wind curtailment.

The schematic presentation of the two-step algorithm is shown in Figure 3.4.

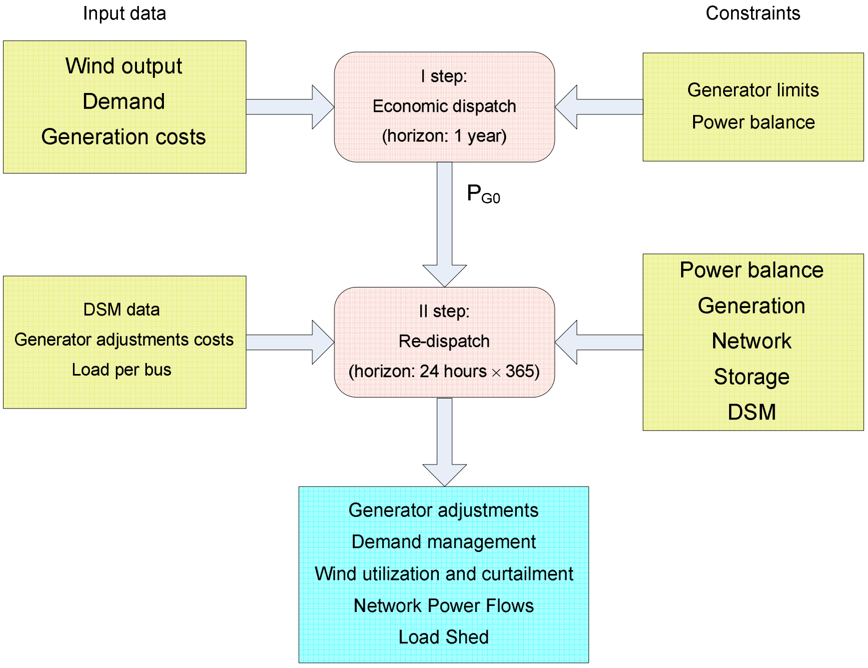


Figure 3.4. Algorithm for transmission network congestion management through controllable loads.

3.4.3 Inputs and outputs to the DSM model

The DSM model described above simulates system operation for one year with hourly resolution. This leads to a large optimization problem with a significant number of decision variables and constraints. The key challenge of this model is to find the appropriate tradeoff between the level of detail needed for the modeling of individual generation, DSM technologies and network parameters while keeping the model tractable and possible to solve in reasonable times.
The list of the input parameters is summarized in Table 3.4:

Table 3.4. Input parameters to the DSM model.

Network	Conventional Generators	Demand	Wind Generation
Topology **Line reactance** **Line Thermal limits**	Marginal production cost Re-adjustments cost Maximum power output Minimum stable generation	Yearly nodal power demand Total nodal load available for control. Control strategies per load type	Wind data represented by hourly time series Installed Wind per Wind Farm or Region

As outputs from the algorithm, generator output power changes, load changes due to DSM, power flows across network branches, potential load shed, wind curtailment, and so on, are obtained. In particular, the *value* of controllable loads is measured using the following set of metrics to capture different types of potential benefits:

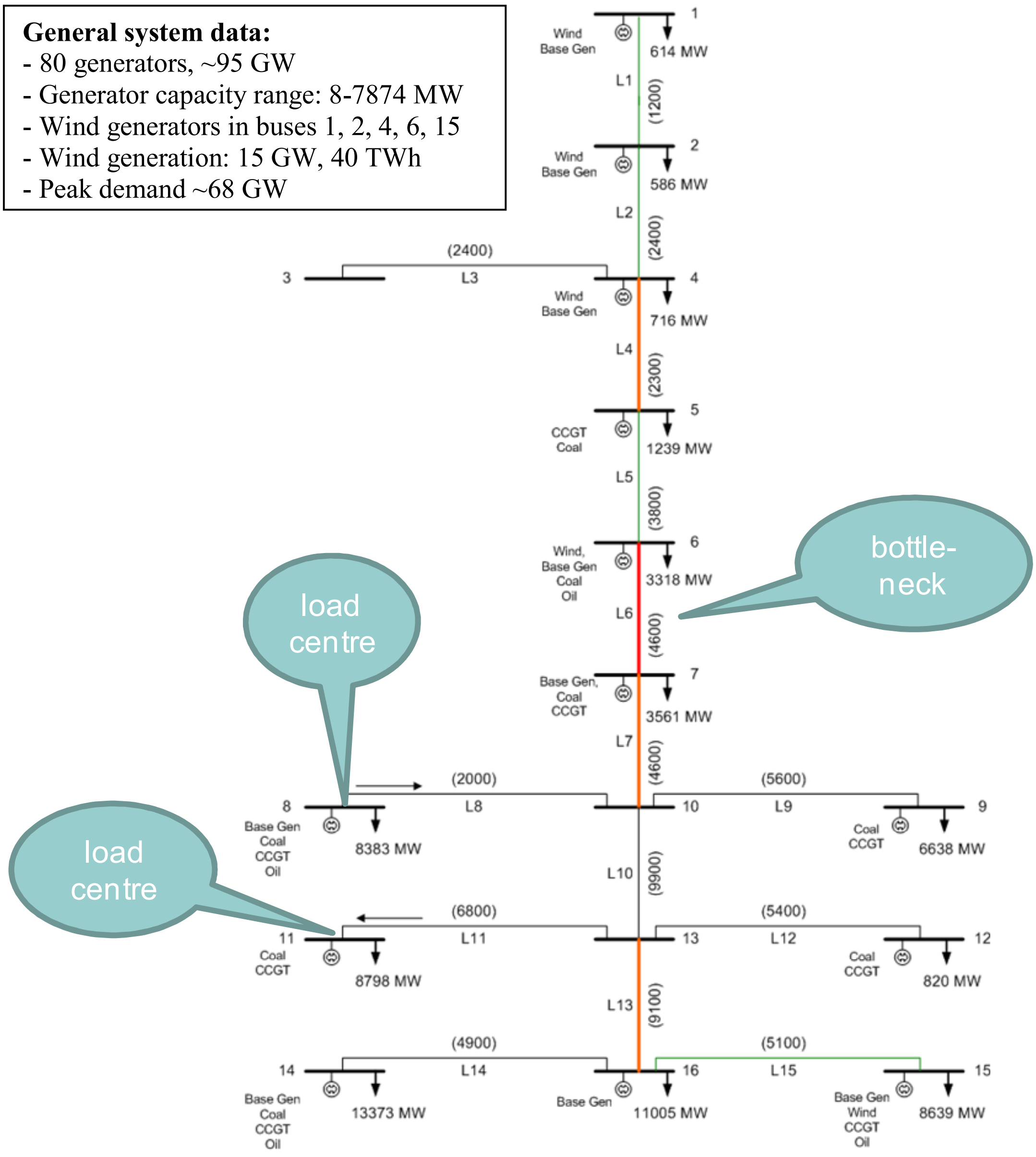
- Reduction in congestion (or re-dispatching) cost;
- Reduction in the wind spilled in the system;
- Reduction in the volume of constrained energy from merit generation.

As apparent from the list of metrics, benefits are computed as the differences between the value of the base case where DSM is not available and the same scenarios with DSM.

3.4.4 Case study application to the simplified UK transmission system

In order to exemplify the model developed for system-level impact of controllable loads on transmission networks, a case study application has been run for the UK. The system under analysis is a simplified model, conveniently divided in 16 areas defined by boundaries, each represented by one equivalent bus, as already illustrated above. The 16 bus-bar system obtained, with also relevant information on generation, demand and lines, is shown in Figure 3.5.

As general considerations, in the north part of the system (buses 1 to 6) there is less generation and less demand, the generation has lower marginal cost, and there is high wind penetration. This corresponds to realistic conditions occurring in Scotland. Wind generators are attached at buses 1, 2, 4, 6 and 15. In the south part of the UK (buses from 6 to 16) there is much more generation, but also huge demand centers are located in the south (particularly in London area). Under such conditions, congestion problems arise. The problem is emphasized when it is required to ship the intermittent energy produced by wind generation from north to south. Line 6 (L6) becomes highly congested. Microgrids could therefore play a prominent role in the mitigation of such congestion problems by aggregating suitable controllable loads. The maximum total amount of load available for DSM within Microgrids is assumed to be 6 GW, and sensitivity analyses are run to check the impact of different controllable load capacities. In terms of types of controllable loads, water heaters have been considered in the analysis, with the three load pattern characteristics given in Figure 3.6. These control schemes represent the demand side flexibility and incorporate the payback phenomenon of thermal loads (more information can be found in [27]). The left part of each control scheme represents load reduction and is described by negative values, while the right part (positive values) represents the payback phenomenon.



General system data:
- 80 generators, ~95 GW
- Generator capacity range: 8-7874 MW
- Wind generators in buses 1, 2, 4, 6, 15
- Wind generation: 15 GW, 40 TWh
- Peak demand ~68 GW

Figure 3.5. Sixteen bus-bar representation of the UK transmission system.

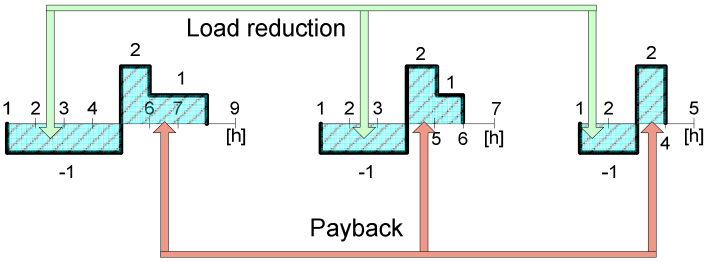


Figure 3.6. Load patterns for the three controllable load types used in the analysis.

3.4.5 Case study results and discussion

The impact of using controllable loads compared to the base case without them is summarized in Table 3.5. The "value" attached to controllable loads is calculated by dividing the reduction in annual re-dispatch cost by the total load capacity available for controllability.

Looking at Table 3.5, controllable loads have an overall positive impact on network operation by reducing the total re-dispatch cost, the total wind spilled, and the total volume of congestion. All these metrics augment for increasing available capacity of controllable loads. In particular, Figure 3.7 highlights how the amount of controllable load has a big impact to the reduction of congested energy, while the impact on the reduction of wind spilled is relatively small, mostly due to the specific siting of the wind mills. On the other hand, it is interesting to point out that the value per kW of load decreases. In fact, after a certain level the amount of energy that can be managed saturates, and thus the specific value decreases, as it can be clearly observed from Figure 3.8. Understanding of this behavior is fundamental for carrying out an appropriate Cost Benefit Analysis (CBA), as controllability also comes at the cost of the relevant communication infrastructure needed.

Table 3.5. Impact of controllable load on the transmission system operation.

Controllable load available capacity	**Annuatised Value**	**Reduction in re-dispatch cost**	**Reduction in wind spilled**	**Reduction in volume of congestion**
[GW]	[£/kW/year]	[$\times 10^6$ £/year]	[GWh/year]	[TWh/year]
1.5	34.3	51.5	57.4	0.6
3	17.9	53.8	66.4	1.1
4.5	12.2	55.1	69.5	1.5
6	9.32	55.9	71.1	1.8

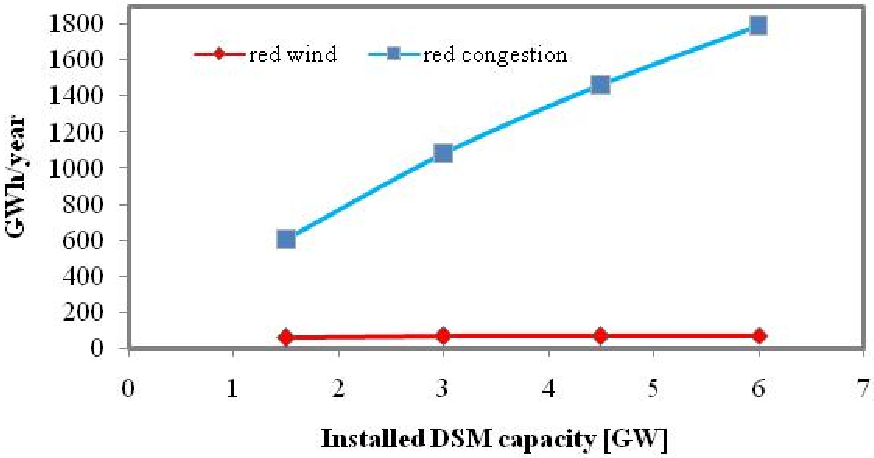


Figure 3.7. Reduction in wind spilled and reduction in congested energy.

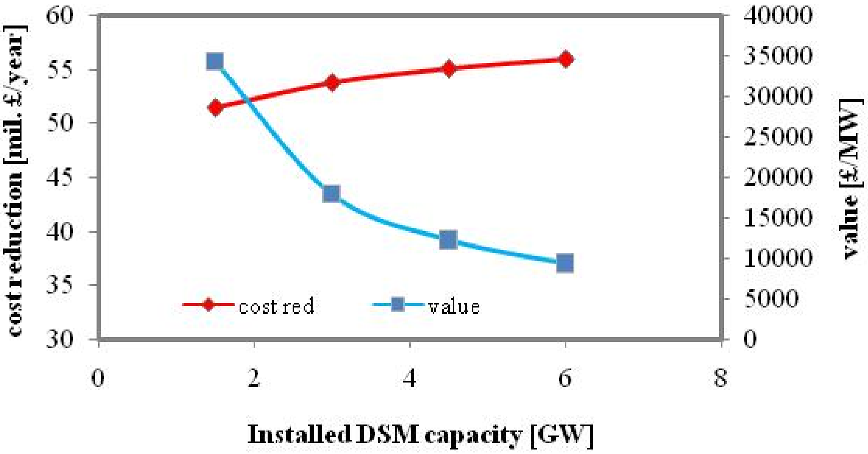


Figure 3.8. Reduction in cost obtained with controllable loads (compared to the base case).

Figure 3.9 shows the total yearly increased energy “*Pg_plus*” and the total decreased energy “*Pg_minus*” due to re-dispatching of generators for each bus in the system and in the case with and without controllable loads. It is obvious that the generators in north decrease their outputs, while those in south increase. This is the consequence of the fact that the marginal cost of northern generators is lower than the southern, so during economic dispatch (1^{st} step of the algorithm) engaged were mostly the generators in the north. However, due to network congestion, electricity cannot be transmitted from north to south, so the generators in the south must increase their production, and those in the north, due to power balance between generation and demand, must decrease their outputs. Controllability of loads can clearly lead to change the generation re-dispatching patterns aimed to avoid tie line bottlenecks, with an eventual overall congestion cost decrease.

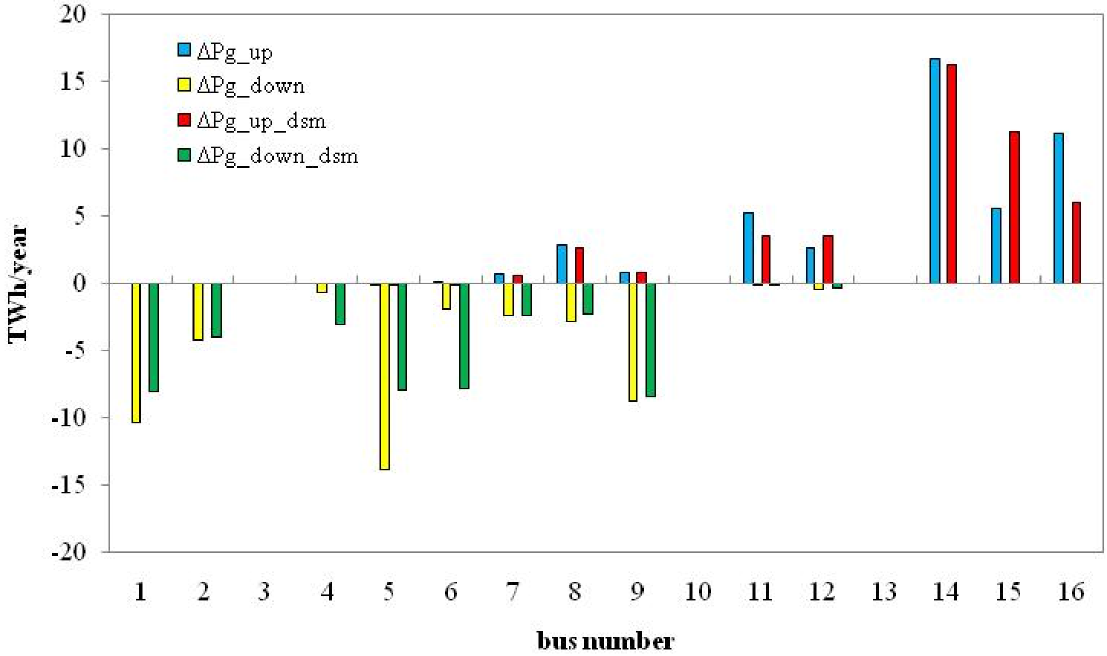


Figure 3.9. Rescheduled generation energy: base case vs. DSM enabled by aggregated controllable loads in Microgrids.

More punctual insights on the operation of controllable loads can be highlighted from Figure 3.10, showing the annual energy that is managed through controllable loads. It can be appreciated how DSM is mostly active at the load centres of bus 8 and bus 11, and the DSM activity increases for larger available capacity of controllable loads. This analysis can be effectively used to establish where to install load controllability facilities within Microgrids, with an investment value that can extrapolated as from Table 3.5.

Further information can be provided by analysis of the utilization of different lines. This is illustrated in Figure 3.11 for the case with 3 GW of controllable loads, where it can be noticed that the line *utilization factor* (defined as the total annual flow of energy - in either direction - through the line, compared to the maximal possible energy that could be transferred by that line) is increased by DSM for all lines except LN 07 and LN13. In fact, L06 represents a bottleneck practically splitting the network into two parts from north to south, and the capacity of L07 and L13 is relaxed while the other lines are more used. In practice, controllable loads prove to bring an overall improvement in the transmission asset utilization by minimising congestions and therefore maximising the power flows across lines.

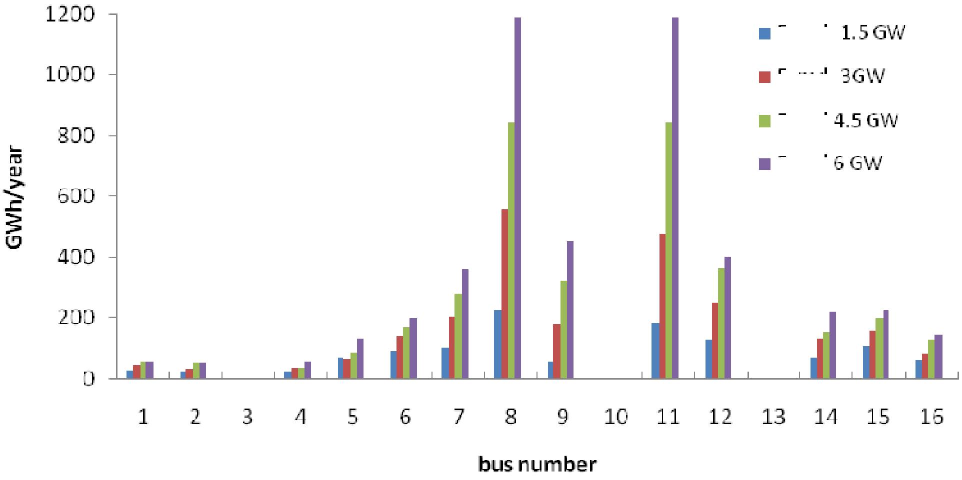


Figure 3.10. Yearly reduced energy due to controllable loads for each bus.

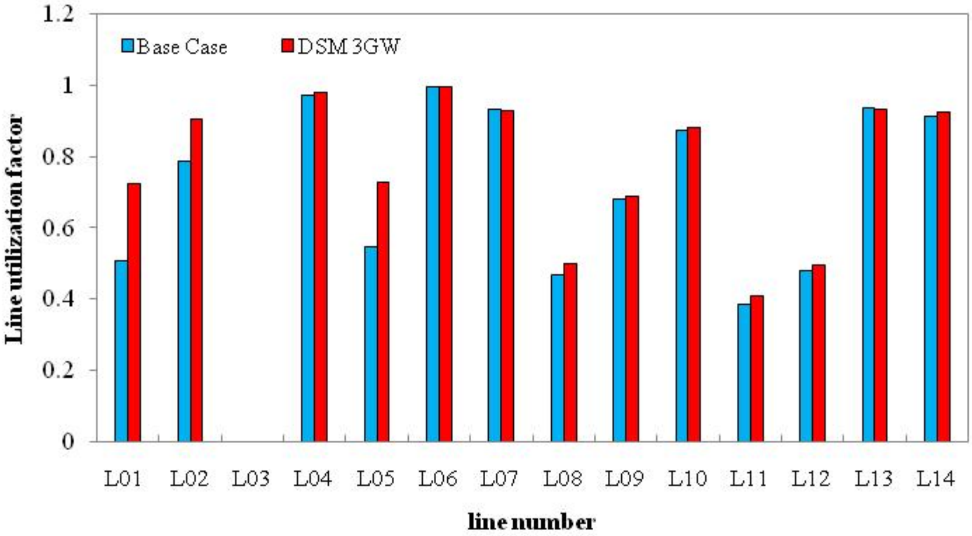


Figure 3.11. Line utilization for 3 GW of controllable loads.

3.5 Final considerations on the value of Microgrids for transmission investment

This chapter has discussed the main aspects relevant to the impact of Microgrids on transmission network development on the basis of a CBA approach to transmission planning. In addition, the value of controllable loads aggregated within Microgrids has been analysed to quantify the potential of DSM for transmission purposes. Relevant impacts and potential value brought by controllability of DER within Microgrids have been analysed by comparing reference cases with no DG or controllable with cases with Microgrids.

The models developed have been exemplified with the UK system.

Regarding the impact of DG within Microgrids for transmission development, the specific results show how, compared to the base case with no DG, intermittent DG (wind) could increase transmission cost by a capitalised value of about £33/kW. However, a combination of wind and CHP compared to the base case could reduce the transmission cost substantially, by a capitalised value of £54/kW. The impact of CHP on transmission is therefore even larger if wind scenario is compared with wind plus DG scenario, with benefit of CHP translating into a capitalised value of £160/kW. This additional value increases by about one fifth if CHP can be controlled within Microgrids, but does not change significantly after enabling 60% controllability. This indicates that the optimal level of controllability, that is, of CHP units potentially to be controlled within MG, is in this case around 60%. The value of controllability is relatively modest compared with the benefits brought by CHP itself, but this could be expected since the network flows are still dominantly controlled using conventional generators. Furthermore, such benefits of enabling CHP controllability in MG have to be balanced with the cost of infrastructure needed to control DG.

As far as controllable loads are concerned, the results in the case study run show that DSM enabled by Microgrids has an overall positive impact on network operation by reducing the total re-dispatch cost in the order of 50 millions £/year, the total wind spilled by 57÷71 GWh/year, and the volume of congestion by 0.6÷1.8 TWh/year. The impact on the reduction of wind spilled is relatively small with respect to the avoided congested energy, mostly due to the specific siting of the wind mills. In addition, the value of controllability normalised with respect to kW of controllable load decreases from 34 to 9 £/kW/year when the dispatchable load changes from 1.5 to 6 GW. This is due to the fact that there is saturation in the amount of energy that can be managed, so that the specific value decreases. This is a key characteristic of controllable loads (as well as of storage [24]) with certain time-constraints, whose application is case specific and whose extent is limited by the relevant conditions. In particular, there is typically an optimal range for which the value of controllable loads is optimal. In particular, with reference to the specific transmission case considered here, if the congested energy or the spilled wind is too little with respect to the installed controllable load, the value of controllability is restricted. On the other hand, if the volume of congested energy or spilled wind is very high, there is little room for time-constrained controllability to bring benefits, and further actions (such as network reinforcements) are needed.

Although the results found are by nature case specific, the qualitative trend can be generalised to other cases. In particular, the models developed provide a solid ground to run CBA-based studies to assess the value of controllability of Microgrids for transmission, as controllability also comes at the cost of the relevant communication infrastructure needed.

4. System-level impact of Microgrids on central generation operation and development

This chapter provides overall views and studies of the impact of Microgrids entailing controllable DG and loads on the development of the central generation system (conventional generators and large scale renewables). More specifically, after discussing the general concept of capacity value of micro-CHP, wind power and PV systems with reference to typical northern situations (UK), a detailed methodology for the evaluation of security of supply in the presence of microgeneration and Microgrids is provided. This comprehensive theoretical and practical analysis (whose details are reported in Annex H2.D) has been run by INESC with reference to the Portuguese case. Then, by using a scheduling model developed by Imperial and explicitly adapted to take into account distributed energy resources, the system-level impact of Microgrids on the economic and environmental performance of different types of power systems with different levels of flexibility (and, in particular, low-flexible systems with plenty of must-run units and wind power) has been assessed. Among other results, the analysis considers the possibility from distributed resources aggregated within Microgrids to support system operation through provision of energy flexibility (load following), reserve and response services, which leads not only to assess the relevant potential benefits on operational cost, but also to estimate the potential value in displacing cost intensive generation and delaying their expansions in case of demand growth, as well as simply displacing old and inefficient central generators.

4.1 Generation capacity contribution of microgeneration and Microgrids

4.1.1 Generalities on security of supply and contribution from Microgrids

In Deliverable DH1 [3] it was generally discussed how, depending on the timeframe considered, microgrid operation could influence short-term balancing (from seconds to days) and long-term capacity provision (from months to years) in order to keep the system reliability and energy supply power quality levels within the permissible limits.

Focusing on generation adequacy contribution, the challenging aspect relevant to microgeneration operation is that power output of most of RES and in general DG technologies is intermittent, which is caused either by the natural variability of primary energy sources or by their operational mode (for instance, the heat following mode of CHP systems). This affects their *capacity value* which is linked to the concepts of overall adequacy of the generation capacity and the long-term reliability of the system. Reliability based generation capacity adequacy assessment techniques [20] are generally employed to determine the conventional generating capacity requirements in systems with and without RES and DG. The difference between the conventional generation capacity amounts needed between the two alternative scenarios indicates the *capacity credit* (CC) of RES and DG.

More in general, the *security of supply* is defined as the ability of a power system to serve the forecasted load, with a specified reliability level. It is a primary objective of any power system, because of the important costs (security, economical, social and political) that result from an inadequate level of security. There are two main components affecting the security of supply, namely:

1. Generation adequacy, which has to do with the ability of the generation assets to cover the expected values of load, including the system losses.

2. Transmission adequacy, which is related to the ability of the transmission system to ensure the needed power flows between the generation and the load points.

Because of its location in the electrical system (LV networks), micro-DG and Microgrids contribute to improve both components of the security of supply. In addition, a number of (mostly economic) factors contributing for the reluctance to the investment on conventional power plants tend not to exist in the micro-generation case. Therefore, the expected dissemination of these systems may result on a valuable contribution to the security of supply. Moreover, this contribution tends to increase when the transmission adequacy decreases, as generation is situated on the distribution network side. It is interesting to notice how this is an opposite situation to the one occurring for conventional generation, where the limitations of the transmission system influence negatively generation contribution to the satisfaction of the system load. However, once the transmission networks exhibit high reliability, their influence on the security of supply tends to be low. On the other hand, the reliability of the distribution networks may influence negatively DG contribution. Therefore, in this work it is assumed that the contribution of DG to security of supply is limited to the improvements on generation adequacy.

The specific contribution of a Microgrid to the security of supply is a result of the ability of those structures to manage (or partially manage) their internal load and generation. Thus, the contribution of a Microgrid is influenced by the characteristics of controllability of their internal DG systems and loads. Concerning DG, only micro-CHP systems with ability to store the thermal energy may be assumed as controllable. In fact, only those units may respond to the needs of the electrical system without wasting the thermal energy (preserving the principle of combined heat and power generation). As a consequence of such control, those microgenerators tend to be always available to respond to capacity scarcity situations. In alternative, micro-CHP systems could operate coupled to an auxiliary boiler, although this would lead to smaller overall generation efficiency. Regarding PV and micro-wind systems it is important to stress that those units are not controllable, since their generation is influenced by the availability of the primary resources.

Concerning the load, it is important to emphasise that the contribution of Microgrids to generating adequacy comes from the ability of those entities to interrupt part of it when a situation of generation scarcity exists. Microgrids are indeed in excellent position to participate in mechanisms of active load management, namely through their ability to interrupt internal load. Once those structures may be used to interrupt the less important loads (heat load, cooling, etc...), the interruption may be done, sometimes, without noticeable effects on consumers (reducing the potential economic cost that results from the load interruption).

4.2 General discussion on DG contribution to security of supply in a Northern European country case

4.2.1 Combined Heat and Power (CHP)

As widely discussed in Deliverable DH1 [3], micro-CHP units are generally adopted for domestic applications ranging between 1 and 10 kWe and are normally connected at 230V. Larger CHP units, although still connected to MV, could be used in small commercial and industrial centres and could be for instance based on MTs.

At this scale, CHP systems operating at individual buildings are typically driven by heat demand, with electricity somehow being a by-product. The capacity credit of small-scale CHP units mostly depends on their flexibility to supply system peak demand. If we consider Northern countries such as the UK, heat demand has a strong correlation with electricity consumption especially in the cold weather condition. Therefore, CHP can be used to reduce peak demand during winter peak. On the contrary, during hot weather condition there is a little need of heat generation which inhibits the use of CHP for capacity provision.

Figure 4.1 exemplifies the conventional capacity that can be displaced by micro-CHP. The studies were conducted on the UK system and for different penetration levels of DG, by overlapping the overall system demand profile under peak conditions with typical electricity production schedules from CHP following heating domestic load profiles. Although no reliability aspects were taken into account in estimating the capacity credit of micro-CHP, it has to be highlighted that the *availability* factor of domestic CHP is typically quite high (even above 90%), so it is less relevant compared to the *diversity* of its utilization during peak demand, which has been taken into account although in an to an approximate way.

In terms of numerical results, it can be appreciated how relatively small penetration of micro-CHP, e.g. 2 GW can displace about 1.4 GW conventional capacity (capacity credit of 70%), owing to the good correlation between heat-driven generation patterns and system demand. However, once the penetration level increases, the ability to displace conventional generation capacity reduces. At 10 GW, which is a likely estimate for the UK in the upcoming year, the capacity credit reduces to some 40%. At the point where the peak demand on the system minus the output of micro-CHP (that is, the net demand as seen by conventional generation) is driven no longer by winter peak demand but by summer peak demand, increasing further the installed capacity of micro-CHP will not reduce conventional generation capacity which is needed to secure summer peak load. This leads to the saturation that can be appreciated for about 35 GW of installed CHP, which roughly corresponds to 50% of the current demand, for which the relative capacity credit is only 25%.

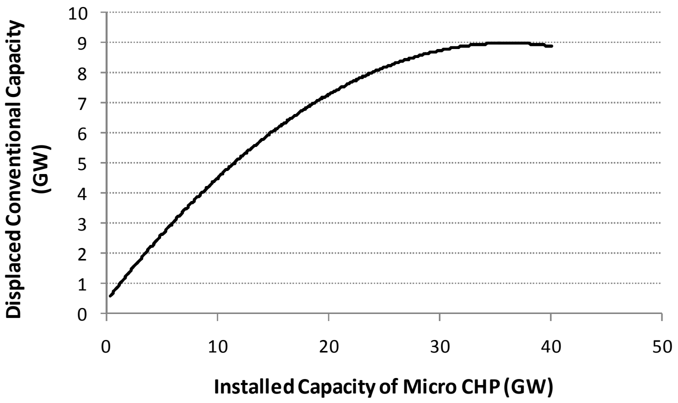


Figure 4.1. Conventional generation capacity displaced by micro-CHP.

However, if micro-CHP can be controlled within Microgrids to respond to electricity demand without being constrained by heat requirement, it could increase its capacity credit, although this will lead to additional costs due to the reduction in overall cogeneration efficiency, in case cost of storage systems and/or auxiliary boilers, and the cost of enhancing its controllability. More details on these aspects are provided below and in Annex H2.D.

4.2.2 Wind Power

In [28] the capacity credit of wind power in the UK was calculated for two different scenarios of geographical distribution of wind power. In this respect, Figure 4.2 shows the results of analyses carried out for a range of wind penetrations to examine the generating capacity of conventional plant that can be displaced by wind, while maintaining the risk of loss of supply at the historical level of 9%. The results indicate a limited capability of wind power to displace conventional capacity. 10 GW of non-diverse wind source can displace only 2 GW conventional generators, corresponding to 20% of capacity credit.

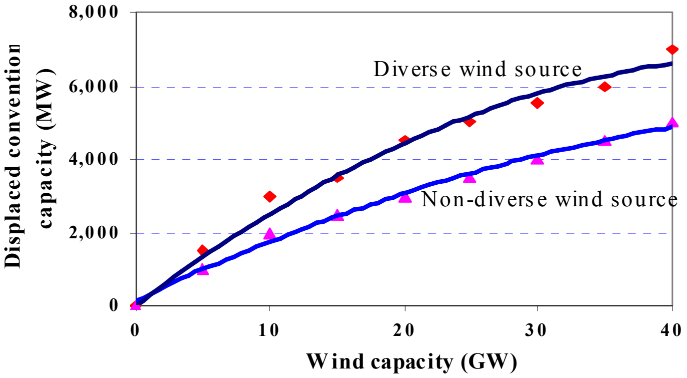


Figure 4.2. Conventional generation capacity displaced by wind power.

4.2.3 Photovoltaics (PV)

Like other RES, the capacity credit of PV is strongly linked to the correlation of its output with peak demand. In a system where peak loads occur during summer daytime, PV has a potential to reduce the capacity of conventional plant resulting in significant capacity credit of this RES. This could be the case in Southern Europe countries. On the other hand, in a system where peak loads occur during winter nights, like in the UK, the capacity credit of PV is practically zero. Details on the capacity contribution of PV in a Portuguese scenario are reported in Annex H2.D.

4.3 Main findings of the studies on generation adequacy in the Portuguese case

This Section reports a short synthesis of the main findings by INESC Porto on generation security of supply and adequacy. Details on methodology, models and calculations can be found in Annex H2.D.

4.3.1 Generalities on the methodology developed for Microgrid contribution to security of supply

In order to evaluate the contribution from Microgrids to security of supply, a probabilistic approach based on a non-chronological Monte-Carlo Simulation process is presented here. To account for the potential dependencies between the seasonal and daily load and generation profiles of the DG units (function of weather conditions) several scenarios were defined. Those scenarios make it acceptable to consider that the random variables (load level and capacity factor of the DG) present an independent behaviour in each scenario.

The developed methodology was applied to a system that has the size of the Portuguese one, namely concerning the load level. The adequacy indices of a base case, without DG, were compared with the indices associated to various penetrations of different micro-generation technologies (CHP, PV, micro-wind) and the existence of Microgrids. Moreover, the contribution of those entities to the generating adequacy of the Portuguese power system was measured by using the concept of capacity credit (CC). As mentioned above, this concept is defined as the conventional generation that may be removed from the system, after adding DG and Microgrids, while maintaining the initial reliability of the system unchanged (detailed on the metrics used are reported in Annex H2.D).

4.3.2 Capacity credit contribution from different micro-generation technologies

Figure 4.3 shows the CC obtained for the different micro-generation technologies considered in the study, assuming an unavailability factor f=10%. The CC values expressed in MW correspond to the amount of conventional generation that can be removed, after the addition of the micro-generation capacity, while maintaining the initial reliability of the system. The percentage values of the CC correspond to the ratio between the CC in MW and the total micro-generation installed capacity.

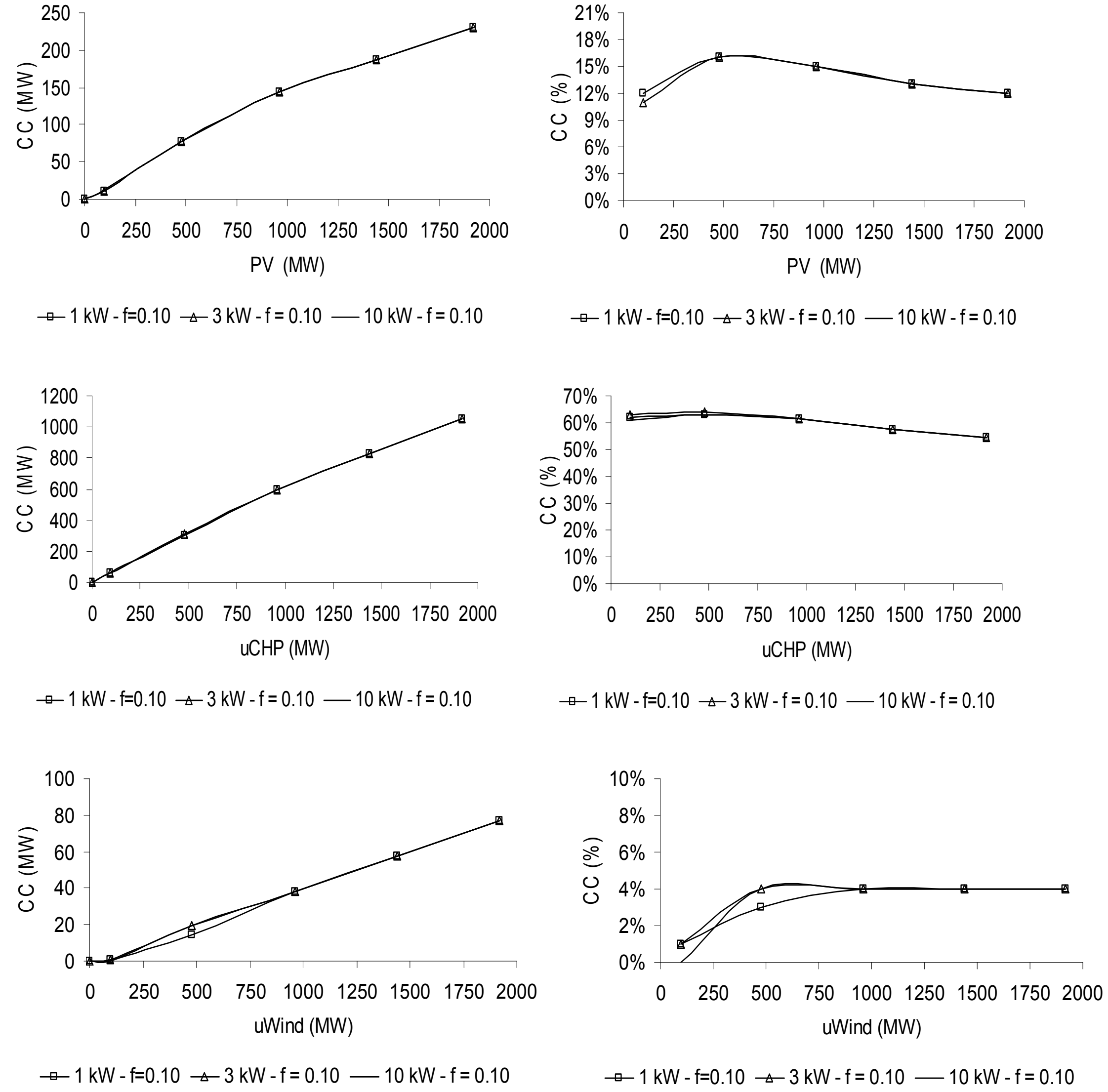


Figure 4.3. CC of different micro-generation technologies

The analysis of the results enables to conclude that the rated power of the micro-generation units does not influence significantly the CC to be allocated to those units. Another important conclusion that may be extracted from the results has to do with the behaviour of the percentage value of the CC. At the initial stage (up to approximately 500 MW), the CC increases with the increase of the micro-generation installed power, declining afterwards.

The influence of the micro-generation unavailability on the CC is illustrated in Figure 4.4. This influence is more significant than the one of the rated power of the micro-generation units, however still limited.

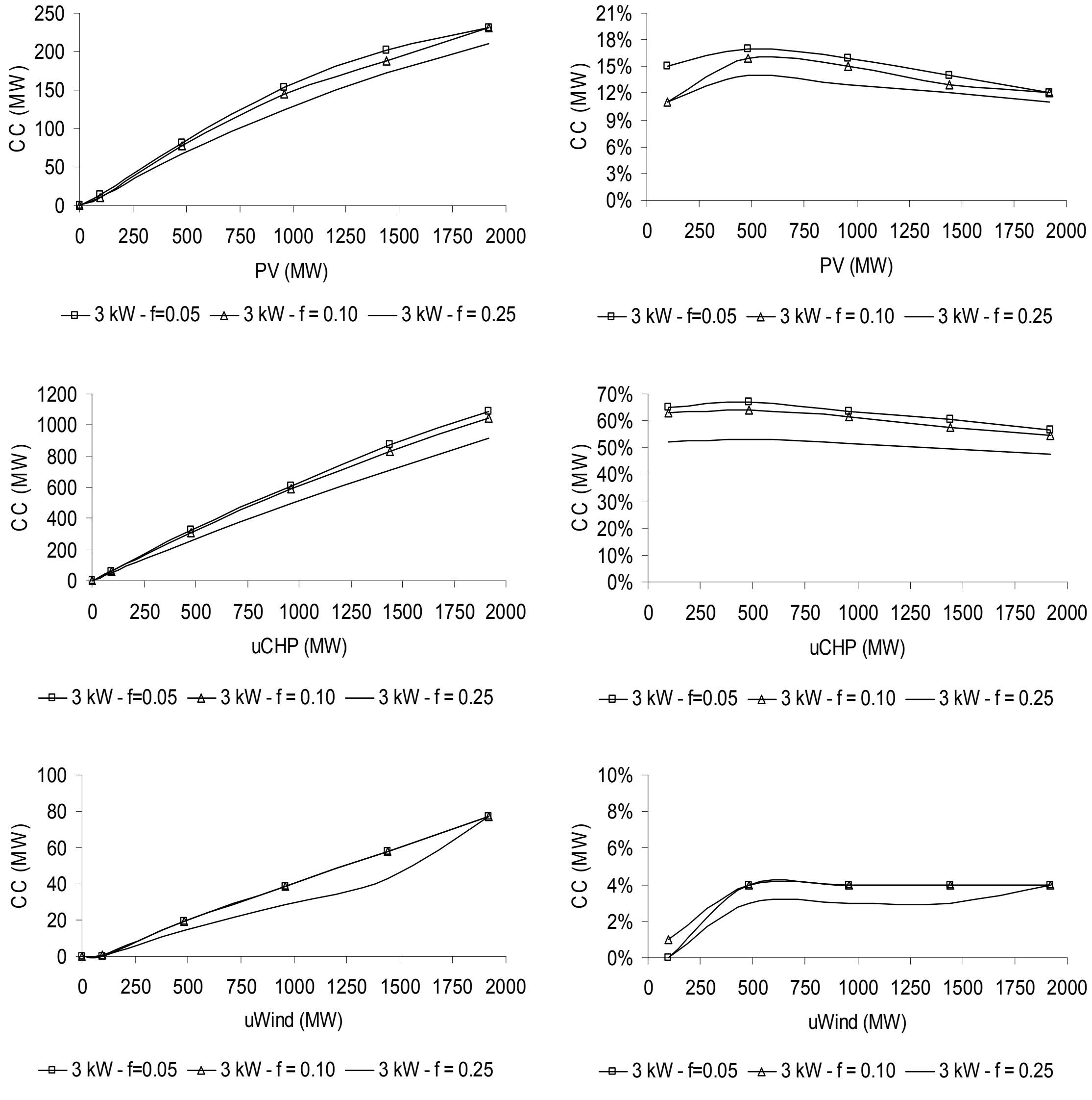


Figure 4.4. Influence of the unavailability of micro-generation technologies on the CC

Figure 4.5 allows comparison of the CC to be allocated to each of the micro-generation technologies considered. An important conclusion that can be drawn from this figure is that the influence of the micro-generation penetration level on the CC tends to be limited. This is an important feature, namely from the regulation point of view (once it allows establishing CC values that are not significantly affected by the uncertainty on the micro-generation penetration level). Also, comparison of CHP and PV confirm also in the Portuguese case the findings relevant to UK distribution networks in terms of capcity support.

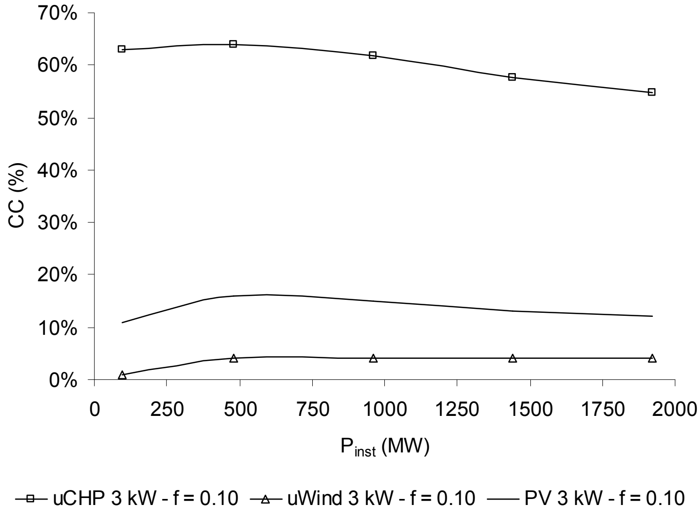


Figure 4.5. Comparison of the CC values for different micro-generation technologies

The CC of each micro-generation technology is influenced by the amount of energy it generates and by the periods where this generation takes place. Dividing the CC of each micro-generation technology by its average annual CF we eliminate the first influence, highlighting the second one. Figure 4.6 shows the CC adjusted to energy (assuming that all technologies generate the same energy). This figure confirms the tendency of the micro-CHP systems to inject power into the grid when it is more needed (from the point of view of the security of supply).

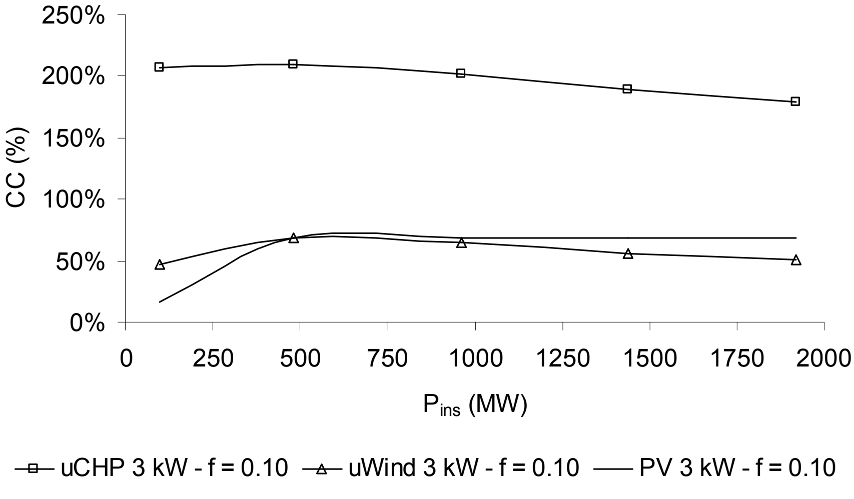


Figure 4.6. CC values adjusted to energy

4.3.3 Specific results for Microgrids

As mentioned above, the major characteristics of Microgrids, namely, their ability to control internal loads and generators, also enable them to contribute to generation adequacy. That contribution depends on the magnitude of load and of mico-generation that can be actively managed by the central controller of the Microgrids. Concerning micro-generation it is important to stress that only micro-CHP systems may be effectively controllable, since the production of PV and micro-wind systems is imposed by the availability of the primary resources. Even for micro-CHP systems, not all units might be easily controlled without waste of thermal energy. As a consequence, only the systems with aptitude to store thermal energy should be accounted for when assessing the generation adequacy, unless at the cost of lower environmental efficiency. Regarding load management, the benefits depend on the share of the internal load that may be shed or shifted from peak period to non-peak periods, similarly to the analysis run in Section 3.4 for transmission congestion release.

Figure 4.7 shows an example of the influence of Microgrids on the CC of micro-CHP systems when different percentages of such systems are assumed as controllable. The increase in CC due to controllability is quite impressive.

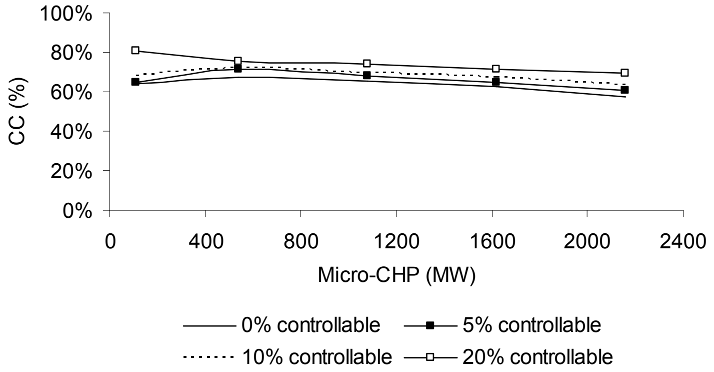


Figure 4.7. Influence of Microgrid on the CC of micro-CHP systems

Concerning load control, Figure 4.8 shows the CC to be attributed to Microgrids when assuming increasing quantities of the total system load as controllable load by Microgrids action. Note that the CC refers to the total capacity of the conventional generation system (10800 MW is this case). Again, the contribution is quite impressive, basically linear with the amount of controllable load.

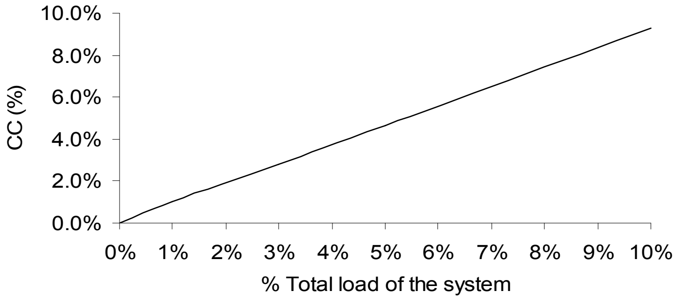


Figure 4.8. CC of Microgrid due to load control

4.3.4 *Concluding remarks on the Portuguese studies on generation adequacy with Microgrids*

This Section has described methodology and results (whose comprehensive details can be found in Annex H2.D) to evaluate the CC of micro-generation systems and of Microgrids. The methodology was applied to the Portuguese system (with some simplifications) and the results were shown and discussed. First, the results show that different DG technologies contribute differently to the security of supply. For instance, a CC = 64% was obtained by a set of 160,000 micro-CHP systems with rated power of 3 kW and unavailability $f = 10\%$. Therefore, the addition of 480 MW of micro-CHP to the Portuguese system enables to remove some 307 MW of conventional generation, keeping the initial reliability of the system. In the same conditions, the CC values of the PV and micro-wind systems are 16% and 4%, respectively. The performance of micro-CHP systems is justified by the fact that these generators have propensity to inject power in periods of higher system loads.

Another important conclusion that can be drawn from the results is related to the limited influence that the rated power and unavailability of the micro-generators has on the CC value. For example, the CC of the 160,000 micro-CHP systems mentioned above increases to 67% if an unavailability of 5% is assumed for the generators. Therefore, halving the unavailability of the generators only increases the CC in 4.7%. If the unavailability is increased by 500% ($f = 25\%$) the CC decreases by 17% to a value of 53%. Similar results can be obtained for the other DG technologies studied. From the regulatory point of view, this is an important feature, once the regulator may adopt reasonable values for those parameters without incurring in significant errors when assessing the CC.

The initial reliability of the electrical system also influences the CC of the micro-generation technologies. In fact, the CC of the micro-CHP units tends to increase when the system has higher initial reliability. The opposite situation occurs in the case of PV and micro-wind systems, whose CC appears more sensitive to the initial reliability of the system then for micro-CHP systems.

Regarding more specifically Microgrids, the results show that the integration of controllable micro-CHP systems within MG increases their CC. For example, the CC obtained by a set of 160,000 micro-CHP systems with rated power of 3 kW and $f = 10\%$ is CC = 69%. However, if 20% of these generators may be controlled by the action of Microgrids, the CC increases by 9%, reaching the value CC = 75%. Similarly, significant CC may be obtained by load controllability within Microgrids. For instance, the control of 5% of the total system load enables to remove 500 MW of conventional generation, that is, roughly 5% of the conventional generation capacity installed in the system. This confirms the strategic role that DSM actions enabled by aggregating Microgrids could play in future system development, as also described elsewhere in this work.

4.4 Role of flexibility provided by controllable generation in Microgrids and dynamic impact on centralized generation

The relatively limited capacity contribution of RES and DG as from above will need support of conventional generation to maintain system security at desired levels, which impacts on the utilization of other technologies present in the system and in retaining greater proportion of conventional generation in the system with reduced utilization. Greater impact on the utilization of the incumbent technologies will translate into higher additional generation capacity costs attributed to these sources [29]. From this perspective, the possibility of controlling DER within Microgrids for ancillary services system support, mainly for reserve and response traditionally provided by conventional generation, will be crucial to minimise the additional costs incurred by conventional generators due to intermittent DG. On these premises, this Section outlines the potential benefits brought by Microgrids providing flexibility and controllability necessary for maintaining secure operation of the system such as load following and frequency control.

4.4.1 Synthesis of dynamic operation of power systems

As introduced in detail in Deliverable DH1 [3], for static analyses of the power system MG can be seen as negative demand, similarly to large-scale RES (wind) that is not specifically considered for system balancing purposes. However, for a realistic evaluation of the costs on power system operation and development from DG technologies, dynamic characteristics need to be taken into account. In particular, a power system must be able to respond to rapid and large fluctuations in supply and demand while maintaining given levels of system security and reliability. Conventional generation does traditionally provide the needed frequency control services, with a level of flexibility (ability of ramping up and down, start up or shut down, and so on) that varies from plant to plant. In particular, reserve services are generally provided by plants rotating in synchronism with the bulk system (*spinning reserve*), to be deployed within 5÷10 minutes, as well as by non-synchronised alternatives (*standing reserve*), such as stand-by generators, to be deployed within some 20 minutes. Normally, spinning reserve is called in action first since it exhibits lower utilisation cost and is thus used to target relatively more frequent and smaller imbalances. On the other hand, standing reserve exhibits lower holding costs but has higher utilisation ones, so it is typically deployed for less frequent but more substantial imbalances.

The amount of reserve required is related to the probability of unbalances between generation and demand. Since the outputs of RES and in general small-scale DG are relatively less controllable and less predictable, additional operating reserve will be needed to cover the uncertainty and variability of their output. This depends on the level of their penetration and the variability of their output over different time horizons. As for the other issues described earlier in this work, for a relatively small penetration of microgeneration additional amount of reserve is negligible. The amount will increase with the level of penetration since the magnitude of the uncertainty increases. Different types of RES impose different types and magnitudes of reserve requirements due to the different level of their output fluctuation and its correlation with demand. These aspects need to be thoroughly understood to assess the impact of Microgrids operation on power systems and the potential benefits from controlling DER to provide system services support.

4.4.2 Generalities on the impact of intermittent sources on frequency services requirements and results from previous studies

Statistical techniques [30][31] can be applied to estimate the operating reserve requirements due to the penetration of RES and DG. In particular, the variations of wind and PV output follows a distribution which is close to a Normal distribution. Therefore, typical approaches are based on estimating additional reserve requirements due to RES as 3 times the relevant standard deviation. In some cases this reserve figure can be extended to 3.5 or 4 to cover the longer tails of the actual distributions. An example is reported in Figure 4.9, illustrating typical fluctuations in wind power output over four hour time horizon.

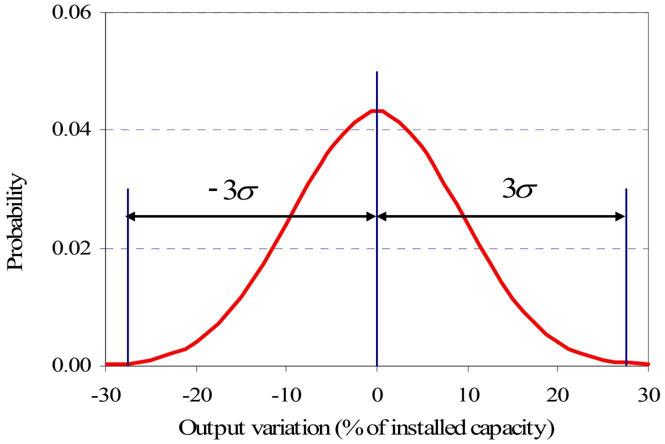


Figure 4.9. Probability Density Function (PDF) of fluctuations in wind power output.

In order to determine the overall reserve requirements, the variations in RES and DG need to combined with the forecast errors in demand and conventional generation across the same considered time horizon. This calculation is performed by using standard statistical approaches to combine errors. It is important to highlight that the diversity occurring among different RES reduces the variation in their cumulative output. A typical example is shown in Figure 4.10, showing the results (in the form of the PDFs of hourly variation) from statistical analysis of the time series data of wind generation for both non-diverse (correlated) and diverse (uncorrelated) UK wind farms. It can be easily observed that the magnitude of power output fluctuations is significantly reduced in the diverse case.

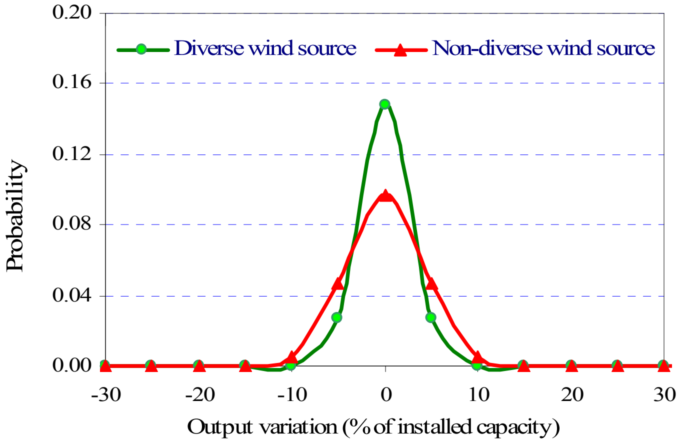


Figure 4.10. PDF of hourly variations in wind output from diverse and non-diverse wind source.

From previous studies run by Imperial College [28][29][32], on the time scale of *primary frequency control* the estimates for increased reserve requirements have resulted in a very small impact. This is due to the smoothing effect of short-term variations of DG and RES power production, uncorrelated with each other and with other fast variations of loads and generation units.

On the time scale of *secondary and tertiary frequency control*, increasing penetration of intermittent sources, and in particular wind, will increase the impact on the net imbalances of the power system. The estimates for the extra reserve requirements due to wind power for UK is in the order of 2-8% of the installed wind power capacity at 10% penetration of gross consumption [33]. Another study [34] also analysed balancing power with respect to the accuracy of wind power forecasting to determine the amount of regulating power that can be reduced by improved forecasting. At 20% capacity penetration, 7% of wind power capacity is needed for balancing, if persistence is assumed. In the hypothesis of a perfect forecast, only 2% additional capacity would be needed at this penetration level. The values shown are only indicative relative and intend to illustrate the beneficial effect of forecasting on additionally required reserve capacity.

In the case of micro-CHP, the additional reserve requirement is expected to be less due to better predictability of its output when aggregated.

As discussed in Deliverable DH1 [3], since generators need to be part loaded and conditioned to provide *spinning reserve* and *stand-by (standing) reserve*, additional reserve requirements will increase the operating cost of such generators that need to be recovered through ancillary service charges. Additional operating costs may also occur since those generators that provide reserve may come from out of merit generation and need to produce electricity at least at minimum stable generation.

Focus on wind studies in recent years, according to [32] with wind supplying 10% of the electricity demand, the required additional reserve capacity for the UK is in the range of 3% to 6% of the rated capacity of wind plant. With 20% wind, the range is approximately 4 to 8%. Accommodating 10% wind in the UK system would therefore increase balancing costs by some 3.9 €/MWh of wind and 20% wind would increase those costs by around 4.6 €/MWh of wind.

These costs are of course dependent upon the technology that is employed to provide these operating reserves. Systems that have sufficient flexibility and low/zero marginal cost generation such as hydro power can incur lower additional operating reserve costs compared to thermal generation based systems.

4.4.3 The role of flexibility that can be provided by Microgrids

On the above premises, the question to be addressed in this work is therefore how microgeneration technologies within Microgrids would impact on the system operational requirements, and whether such technologies can contribute to frequency support to the system. In fact, the scenarios that are envisaged for most EU countries lead to consider an increasing level of inflexibility of the overall system, whether due to additional base-load nuclear or Carbon Capture and Storage (CCS) systems, or intermittent large-scale wind resources. This will eventually mean additional reserve costs, above all for spinning reserve (see Deliverable DH1 [3] for more detailed overview). Therefore, it is crucial to seek for additional means of flexibility. Focusing on microgeneration, in particular, CHP systems that normally are operated under thermal load-following mode could be deployed for grid-related services, above all if equipped with heat storage systems capable to decouple the electrical and thermal loads. Therefore, MG with controllable microgenerators could represent a valuable source of flexibility and provision of system ancillary services that otherwise would be provided by the marginal central generating units. If not, it will be possible to displace only a reduced amount of central generation capacity, needed for system services, and such capacity will operate more frequent in part loaded mode, with far higher costs than currently. Besides microgeneration, support could be provided by controllable loads as well. In this respect, examples of energy balancing support in the presence of intermittent sources and variable flexibility portfolios are discussed in Section 4.5. For system-level applications, indeed, it is expected that the value of controllable sources (DG or DSM) in microgrids will be strongly related to the flexibility of the conventional generation mix, besides the penetration of RES such as wind and further inflexible generation such as CCS. This value is also expected to increase with the increase of the penetration of wind and inflexible sources.

Quantitative analyses in this respect are provided below.

4.4.4 Scheduling model for system-level impact assessment of Microgrids on conventional generation

In order to assess the impact of coordinated Microgrid operation on system performance, a large-scale system scheduling model was used that has been developed by Imperial, and modified to accommodate a range of studies performed within this Deliverable. The model carries out an annual assessment of generation system operation. It optimally allocates generation resources to provide energy, reserve and response services. The model is able to incorporate various generation technologies and their respective capabilities, daily and seasonal changes in demand and different levels of penetration of intermittent renewable electricity. In order to investigate the interaction between Microgrids and the power system, the model was extended to incorporate various levels of Microgrid controllability that could be used by the system.

The key aspect of the model is the ability to capture the interaction between response, reserve and energy provision from generators, taking into account their cost characteristics and dynamic capabilities. Considering response services in isolation from reserve and energy would indeed provide unrealistic results. Conventional generation units are represented through generic units of different technologies most widespread across Europe, namely, CCGT, coal, and nuclear. In addition, also CCS plants are simulated as must-run units, so that future generation mixes as envisaged in low-carbon strategies of several governments can be analysed as well. The data on generator physical parameters, cost, efficiency and emission characteristics were taken as typical for particular technologies.

Following are the key features of the model:

- Commitment and dispatch of large-scale generation units is done through minimising operation costs, considering: generation start-up, incremental production costs, and cost of holding standing reserve in stand-by plants. Generator cost characteristics are modelled in a way that allows accounting for decreased operating efficiency when operating part-loaded.
- Consideration of generators' technical limits and capability to change the output:
    - Generation technical limits;
    - Ramp rates;
    - Minimum up and down times;
    - Must-run status (mostly relevant to nuclear or CCS plants).
- Demand balance constraint based on the criterion that the generation schedule needs to supply the net demand (system demand minus wind output) at all times, where net demand is the difference between demand and wind generation.
- Deterministic requirements constraining the minimum levels of:
    - *Primary response*: provided by part-loaded conventional generation plants, and potentially Microgrids;
    - *Spinning reserve*: provided by part loaded plants and set according to an optimal allocation obtained off-line;
    - *Standing reserve*: provided by stand-by plants and set to provide the difference between total reserve required and the spinning reserve allocated.
- The model captures the interaction between provision of response and spinning reserve by the same unit. The capacity available for spinning reserve is taken into account when setting the generator's available response capacity.

The system operation is simulated for one year with half-hourly time resolution, resulting in 17,520 values of system demand and wind output profile, both of which are based on UK system data. However, in terms of strategic information provided by the model and the analysis, the results can be reasonably generalised to other countries. The results obtained for each scenario represent the minimum operation cost to supply net demand

and ensure pre-defined levels of response and reserve. Additionally, the model provides information on CO_2 emissions and wind curtailment necessary to balance generation and demand. The latter may occur in certain time instances when there is excess energy in the system, due to certain conventional plants being kept part-loaded to provide reserve or response services, supplying at the same time electricity at the level of at least their minimum stable generation.

The optimal economic operation of the system is calculated taking into consideration daily and seasonal demand variations and variations in wind output over the year. To properly simulate system operation, and capture all relevant parameters, the methodology includes the following considerations:

- Modified *system response requirements* were generated through adjusting system primary response requirements to incorporate the uncertainty of wind. Statistical properties of actual wind data were incorporated into calculations of new system response requirements which capture the additional uncertainty introduced by various penetration levels of wind generation, as mentioned in Section 4.4.2. The new response requirements ensure that the risk of violating frequency limits remains unchanged.
- *Reserve requirements* are defined taking into account wind and demand forecast errors and generation outages within operational reserve time scales. This was incorporated into calculations of the additional reserves (the forecast *lead time* used is 4 hours, corresponding to the expected time required to start a new plant). This process was carried out for different wind penetration scenarios. The reserve requirements ensure that wind uncertainty is taken into account without changing the operational risk accepted by the system operator. The allocation between spinning and standing reserve is optimised externally to minimise expected imbalance costs for different structures of the generation system.
- *CO_2 emissions* from fossil fuel-based electricity generation are modelled considering International Panel on Climate Changes (IPCC) emission factors for different fuels. The emission factors establish a proportional relationship between primary energy used for generating electricity and the CO_2 emissions caused by the process. This implies that CO_2 emissions per unit of electricity output depend on the efficiency of the technology, *i.e.*, that emissions per megawatt-hour of electricity generated increase when power plants are part-loaded.
- The variation of wind generation over the year is taken into account by using an appropriately constructed wind time series based on typical UK values, which allowed for simulating the wind outputs for different wind penetration levels.

Microgrids are incorporated into the scheduling model by assuming they cover a part of the electricity demand. Their electricity output profile is related to their heat output requirements in a manner that depends on the level of controllability of micro-CHPs (this is elaborated in the following section). In this analysis one representative heat consumer type was assumed with nine representative heat demand profiles used to model weekly and seasonal oscillations in heat demand that needs to be covered by Microgrids. Nine profiles refer to particular combinations of day types (workday, Saturday or Sunday) and seasons of the year (summer, winter or spring/autumn), for which characteristic profiles were available. The half-hourly profiles are depicted in Figure 4.11.

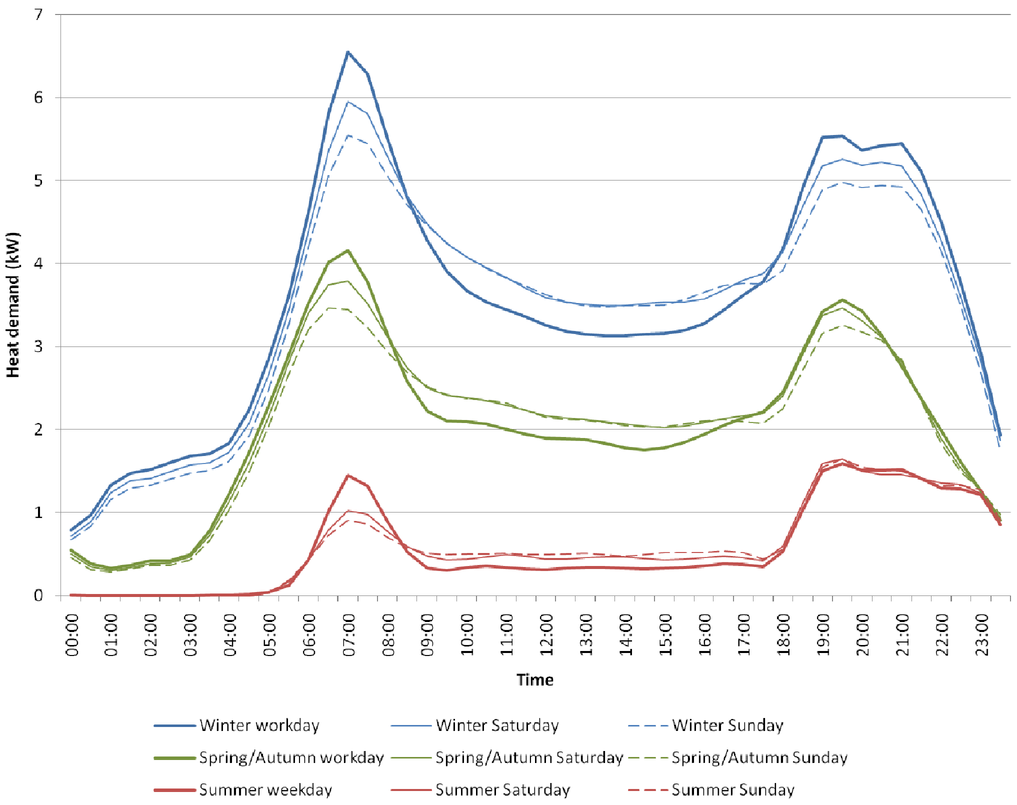


Figure 4.11. Heat demand profiles for micro-CHPs

The heat-to-electricity output ratio of micro-CHPs was assumed to be 6.5, so that the maximum electricity output for one CHP unit would be 1 kW. The number of micro-CHPs in the system, *i.e.*, the penetration of Microgrids, was scaled up to account for different penetration levels. Cases considered in this analysis included the total electrical capacity of CHP-based Microgrids in the amount of 5%, 10% and 20% of peak system electricity demand (which in this case was 66.7 GW).

Another important micro-CHP parameter was its cost, which was assumed to be £20/MWh. This cost is significantly lower than conventional generation plants, ensuring that micro-CHPs are always included in the dispatch. This low figure is justified by the fact that the actual cost of gas for electricity generation from CHP can be discounted by an equivalent amount needed to produce heat. For example, this cost allocation procedure can be based on incremental efficiencies (see for instance [35][36]).

4.4.5 Case study examples

The impact of Microgrids on the overall system performance was investigated with a number of different assumptions regarding the flexibility that Microgrids are able to provide to the system. These assumptions are added gradually, starting from the least flexible operation, and ending with the regime where Microgrids are capable of providing a full range of system services. More specifically, here is the description of the four distinctive operating regimes considered in this analysis:

1. *Non-flexible operation.* In this regime it is assumed that micro-CHPs follow their respective heat load patterns, *i.e.*, their electricity output is not flexible. From the system-level point of view, micro-CHP electrical output can be considered as negative demand, which displaces some of the electricity, but almost none of the capacity provided by conventional generation.
2. *Flexible energy balancing.* In the second regime, micro-CHPs are assumed to be allowed to shift their heat and electricity production within a day, provided that the total delivered heat energy is equal to the total daily heat requirements of the consumer for that particular day. Decoupling heat delivery from electricity generation is assumed to have been made possible by installing an appropriate *heat storage*, which can be managed in order to accurately follow consumer's heat load profiles[2].
3. *Flexible balancing with reserve provision.* In addition to balancing energy delivery within a day, this regime further assumes that micro-CHPs are able to provide reserve capacity to the system. By using the non-utilised part of their capacity, micro-CHPs are able to offer *upward* and *downward* reserve capability to the system operator. Micro-CHPs therefore effectively compete with large-scale conventional generation in providing reserve services to the system, resulting in a more efficient system operation.
4. *Flexible balancing with reserve and response provision.* On top of providing energy balancing and reserve services, micro-CHPs are here assumed to be able to contribute to frequency response services as well. This contribution is again delivered from the unused part of micro-CHP capacity at a given time instance, which is now allocated between reserve and response provision (the model ensures that no part of the unused capacity can be used to provide both types of services, but at most one of them, depending on what is optimal from the system point of view).
   In this regard, in analogy to large conventional generators it was assumed that: i) micro-CHPs would provide frequency response only up to a certain percentage of their capacity (e.g. 10%), as currently required by Grid Code; and ii) because of dynamic behaviour of generators providing response, offloading by 1 MW results in response contribution of less than 1 MW (typically 0.5-0.6 MW).

All four operating regimes were simulated as part of the system scheduling model, varying certain parameters, such as Microgrid penetration, wind penetration and system

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[2] Although charging and discharging losses are inherent to any storage system, they were not considered in this analysis for simplicity reasons.

flexibility, to investigate the sensitivity of the impact of Microgrids on system operation under a range of circumstances. A summary of cases considered is given in Table 2.1.

Table 4.1. Microgrids case studies for system-level impact on generation

System parameter	***Values considered***
Microgrid operating regime	Non-flexible Flexible energy balancing Flexible balancing with reserve Flexible balancing with reserve and response
Microgrid penetration	5% of system peak 10% of system peak 20% of system peak
Wind capacity	0 GW 20 GW
System flexibility	Highly flexible system Medium flexible system Low-flexibility system

The system flexibility parameter primarily refers to the ability of conventional plants to change their output, expressed through their ramp rates, minimum up and down times, etc. In this analysis, highly flexible system is based on faster-ramping units (such as e.g. CCGT units), and medium flexible system is based on units with slower ramping capability, but with lower variable operating cost (such as e.g. coal-fired units). Both of the two systems have a certain moderate quantity of inflexible must-run units (such as e.g. nuclear or CCS plants). Low-flexibility system on the other hand has a higher share of must-run generation, as well as a very high level of installed wind capacity (30 GW). Details on the composition of each system type are laid out in Table 4.2.

Table 4.2. Capacity breakdown for different system types

System type	***High-flexibility units***	***Medium-flexibility units***	***Must-run units***	***Wind capacity***
Highly flexible	60 GW	-	12 GW	0 or 20 GW
Medium flexible	-	60 GW	12 GW	0 or 20 GW
Low-flexibility	-	60 GW	15 GW	30 GW

The effect of introducing Microgrids into the electricity system is evaluated by comparing system performance indicators in cases with Microgrids with a reference case where no Microgrids exist in the system. This permits the quantification of the effect on system cost, carbon emissions, curtailed wind energy, and conventional capacity needed on the system.

The following section presents the numerical results and discusses the main drivers for the system-level value arising from the usage of Microgrids within the electricity system.

4.4.6 Discussion of the results

In order to provide a uniform platform for comparing performance parameters for different Microgrid penetration levels, the results obtained through simulations are normalised and expressed per kilowatt of micro-CHP electrical capacity. In other words, system savings will be expressed in pounds sterling per kWe, carbon emission savings in kilograms of CO_2 per kWe, and wind curtailment reduction in kWh of wind energy saved per kWe of micro-CHP capacity.

Cost savings

Figure 4.12 and Figure 4.13 show system cost savings for a *highly flexible system* from using Microgrids for different operating regimes, with Microgrid penetration as parameter. The two figures represent cases without wind and with 20 GW of wind, respectively.

It is clearly visible that Microgrid-related benefits, expressed per unit of micro-CHP capacity, decrease with increasing Microgrid penetration. In other words, because of a saturation effect, first installations of Microgrid capacity bring higher benefits than the capacity added later on. This discrepancy becomes more evident with more flexible Microgrid operating regimes.
One can also notice that the system value of Microgrids for systems with significant wind capacity is higher if Microgrids are able to provide flexible reserve and response services.

Values for less flexible operating regimes do not differ notably between no-wind and wind-rich cases. The least operating regime (which is effectively substitution of electricity normally provided by conventional plants with Microgrid generation) achieves around £80/kWe of system value, and this remains the largest component of the overall savings, even for more flexible operating regimes. In the most flexible regime, the total savings can reach the levels of around £100-£120/kWe, i.e. £120-£140/kWe for cases without wind and with wind, respectively. The main difference between the two cases appears upon introducing reserve provision from Microgrids, which provides higher value in the high-wind case.

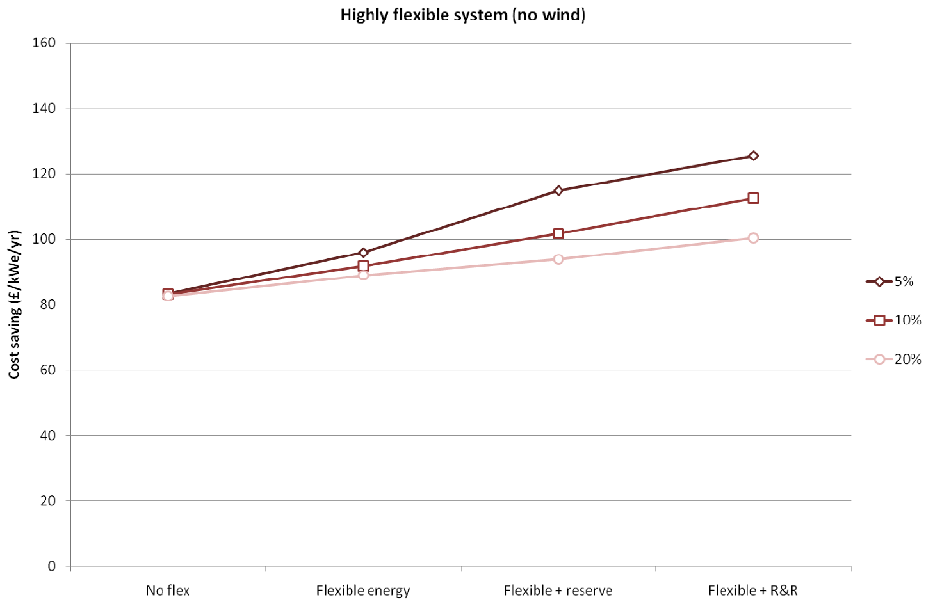

Figure 4.12. Cost savings for the highly flexible system with no wind

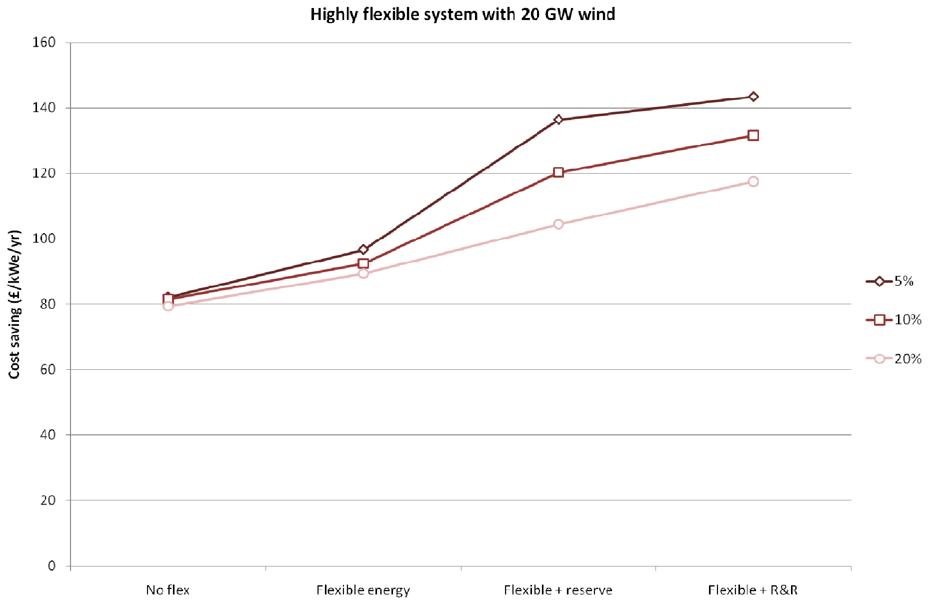

Figure 4.13. Cost savings for the highly flexible system with 20 GW of wind

Cost savings in the case of a *medium flexible system* are depicted in Figure 4.14 and Figure 4.15. Trends are rather similar as for the highly flexible case, the main difference being the overall level of savings, which is markedly lower here (roughly a half of the value for highly-flexible system). This is a consequence of the cost assumptions made for conventional generators in two system types (medium-flexibility system is assumed to consist of cheaper generation units). Again, value expressed per kWe of micro-CHP decreases with higher Microgrid penetration.

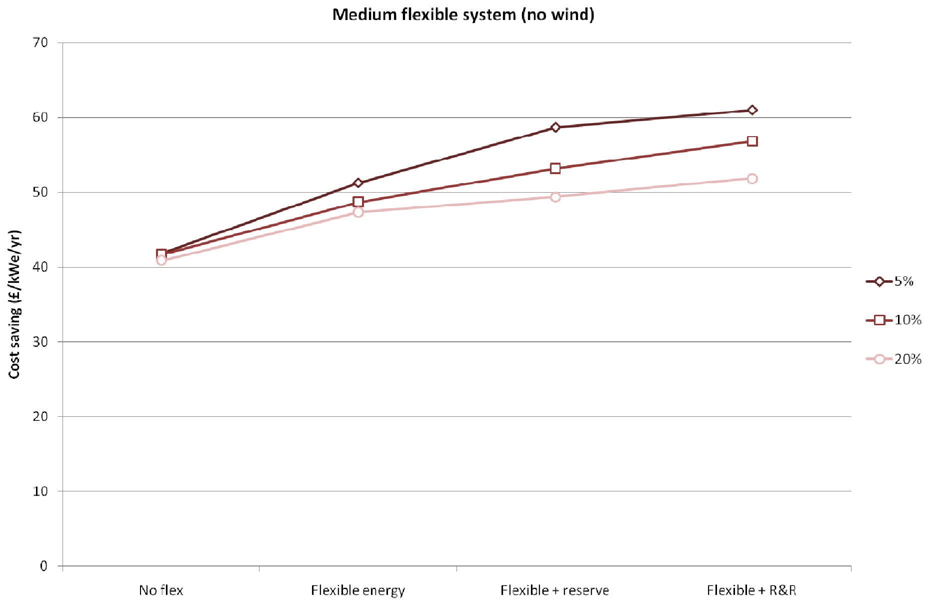

Figure 4.14. Cost savings for the medium flexible system with no wind

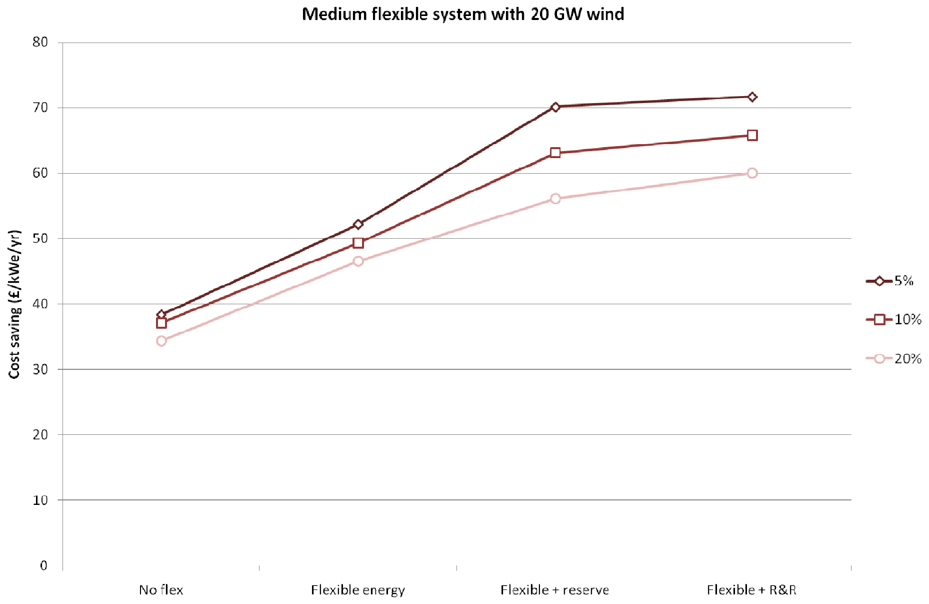

Figure 4.15. Cost savings for the medium flexible system with 20 GW of wind

Finally, when looking at the cost saving profile for the *low-flexibility case* in Figure 4.16, one can notice that most of the added value comes from Microgrids providing reserve services in such a system. Because of a very low flexibility in the system (due to large must-run and wind capacities), adding inflexible micro-CHP profiles as a negative demand helps the system only slightly, since the remaining less flexible conventional units have an even more variable net demand profile to follow.

The largest benefit for the system occurs when reserve provision from Microgrids is considered as an option. Providing reserve from Microgrids increases their system value by a factor of 2 to 3.5. This largely results from releasing a large amount of conventional capacity which is normally used to provide this reserve, and this enables a more efficient operation of the rest of the system.

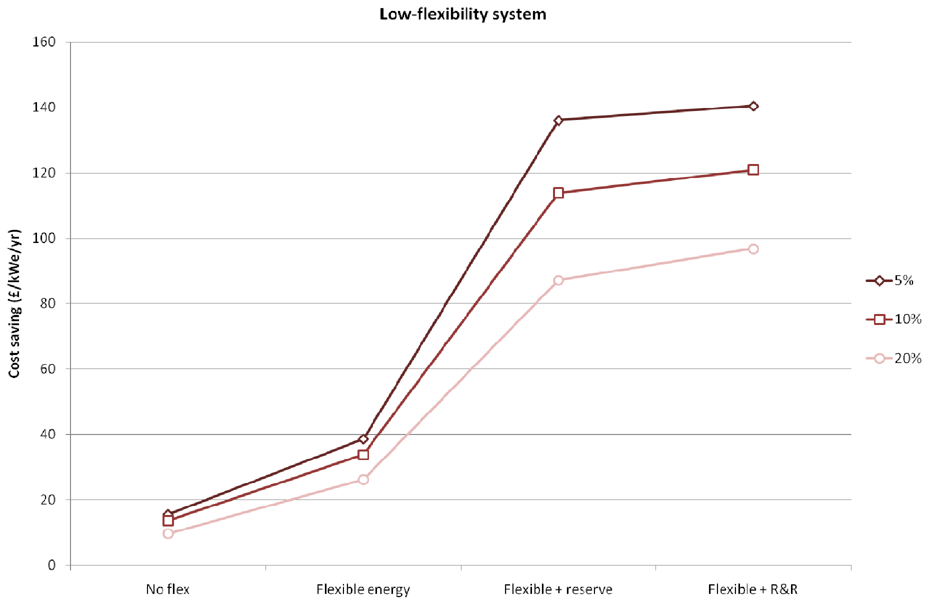

Figure 4.16. Cost savings for the low-flexibility system

Carbon emission reduction

Figure 4.17, Figure 4.18 and Figure 4.19 show the savings in CO_2 emissions achieved through Microgrids operation within the electricity system, for all three system types. Trends in emission savings are very similar to the ones for cost savings, which is not surprising, given that both cost and emission savings come from avoiding the usage of fossil fuels in conventional plants. The only difference is the relative level of these savings for different system types, which results from assumptions made with respect to emission factors from different technologies.

Emission reduction in a highly flexible system is around 0.5-1 kg CO_2/kWe per annum. The same saturation effect as with cost savings is visible for higher Microgrid penetrations, where benefits per unit of capacity diminish. In the medium-flexibility case the emission reduction ranges between 2-3 kg CO_2/kWe, largely as a result of a higher emission factor assumed for medium-flexibility conventional generation (by a factor of around 2.5). In the low-flexible system, this value grows from around 1 to almost 5 kg CO_2/kWe, as flexibility of Microgrids operating regime increases.

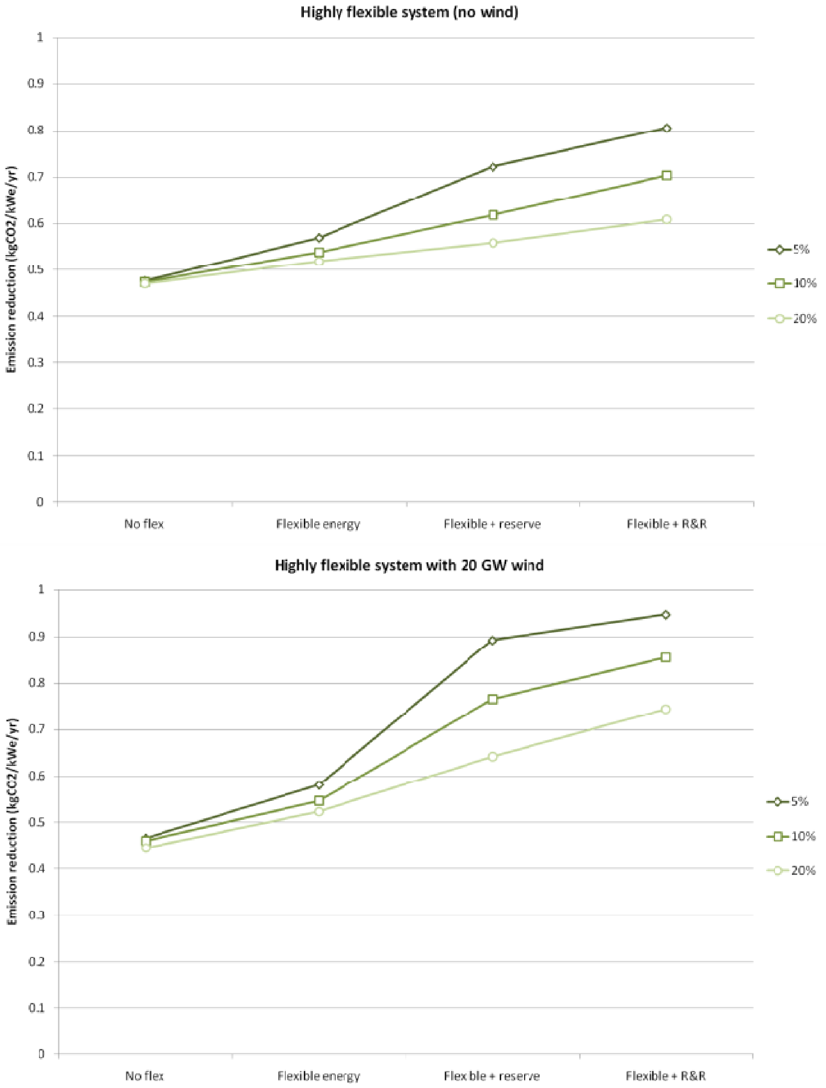

Figure 4.17. Carbon emission reduction for the highly flexible system

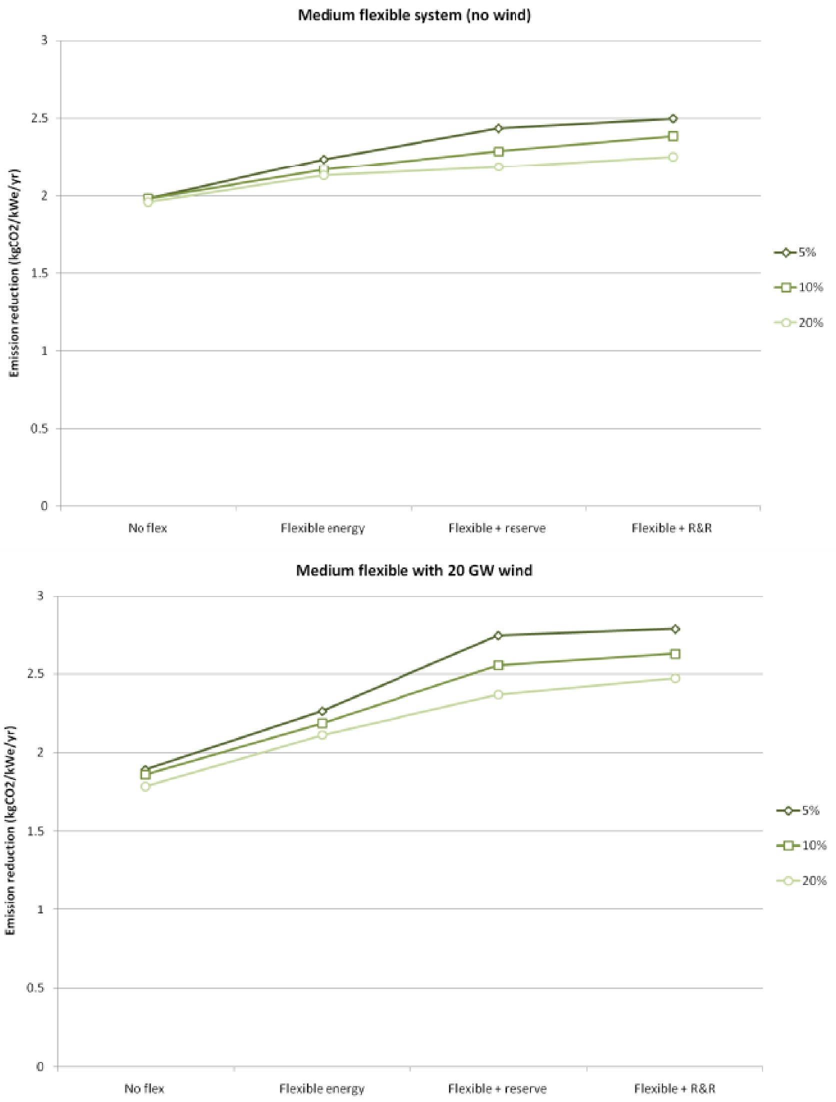

Figure 4.18. Carbon emission reduction for the medium flexible system

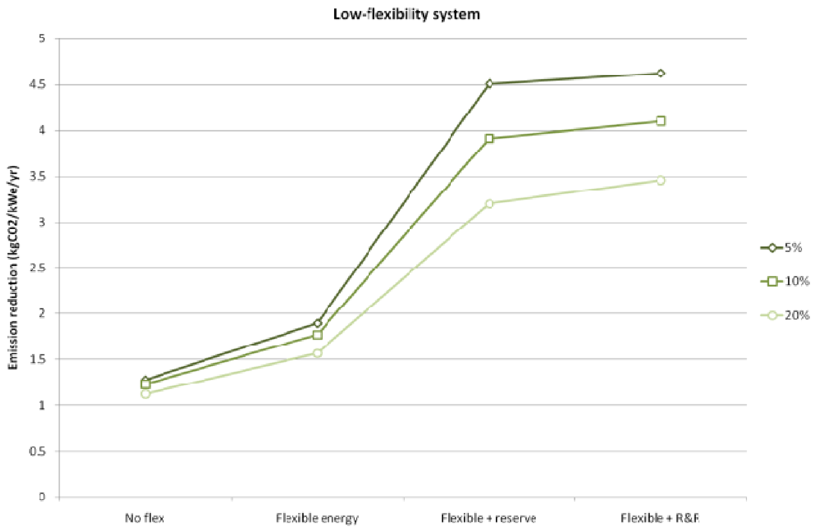

Figure 4.19. Carbon emission reduction for the low-flexibility system

Reducing wind curtailment

It is of particular interest to investigate how the flexibility provided by Microgrids can contribute to reducing the need to curtail wind output in periods of high wind and low demand. This issue is especially important for situations with very high wind capacity present in the system; therefore, only the results for the low-flexibility system are discussed here (Figure 4.20), since in the other two the effects are of minor magnitude.

When operating in an inflexible operating regime (i.e. heat load following), micro-CHPs can actually aggravate the situation regarding wind curtailment. Their fixed output profile, when combined with high wind in periods of low demand, further reduces the net demand to be covered by conventional units in the system. This situation improves slightly with adding balancing flexibility to Microgrids, while a major improvement appears when Microgrids are allowed to provide reserve services (and replace reserve provided by conventional units). In their most flexible operating regime, Microgrids can contribute to reduce curtailed wind output by 0.3-0.8 kWh/kWe, and enable more efficient integration of intermittent wind output.

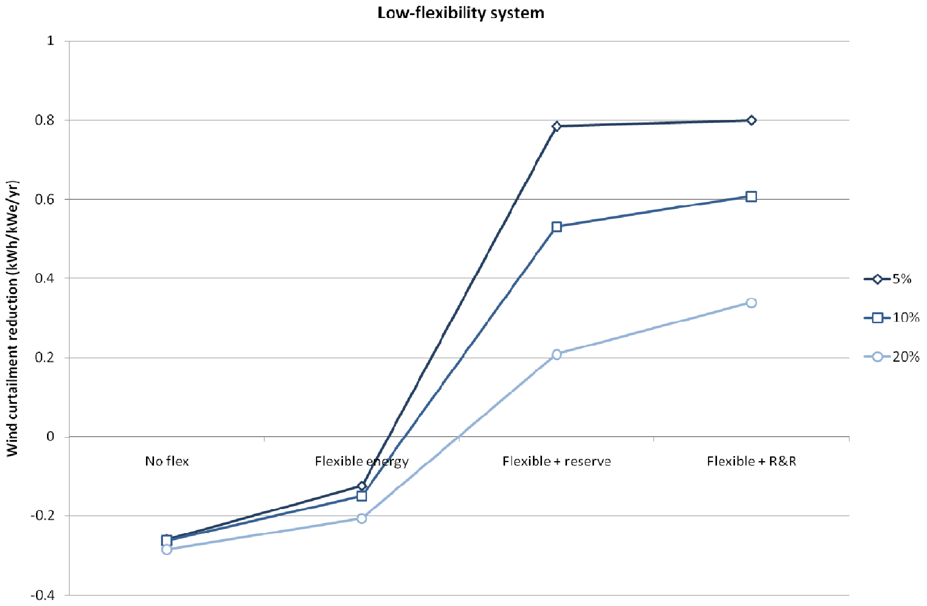

Figure 4.20. Wind curtailment reduction for the low-flexibility system

A valuable insight into the results of this analysis can be made by looking at the incremental value brought about by adding flexible service capabilities to Microgrids operation. In order to illustrate this, Figure 4.21 shows incremental components of system cost savings for the highly flexible system, with 5% penetration rate of Microgrids. It suggests that the majority of the system value is contributed by using electricity from micro-CHPs in the first place (even in an inflexible regime). The reserve component of the value becomes significant in case with higher wind penetration, due to higher reserve requirements in such conditions.

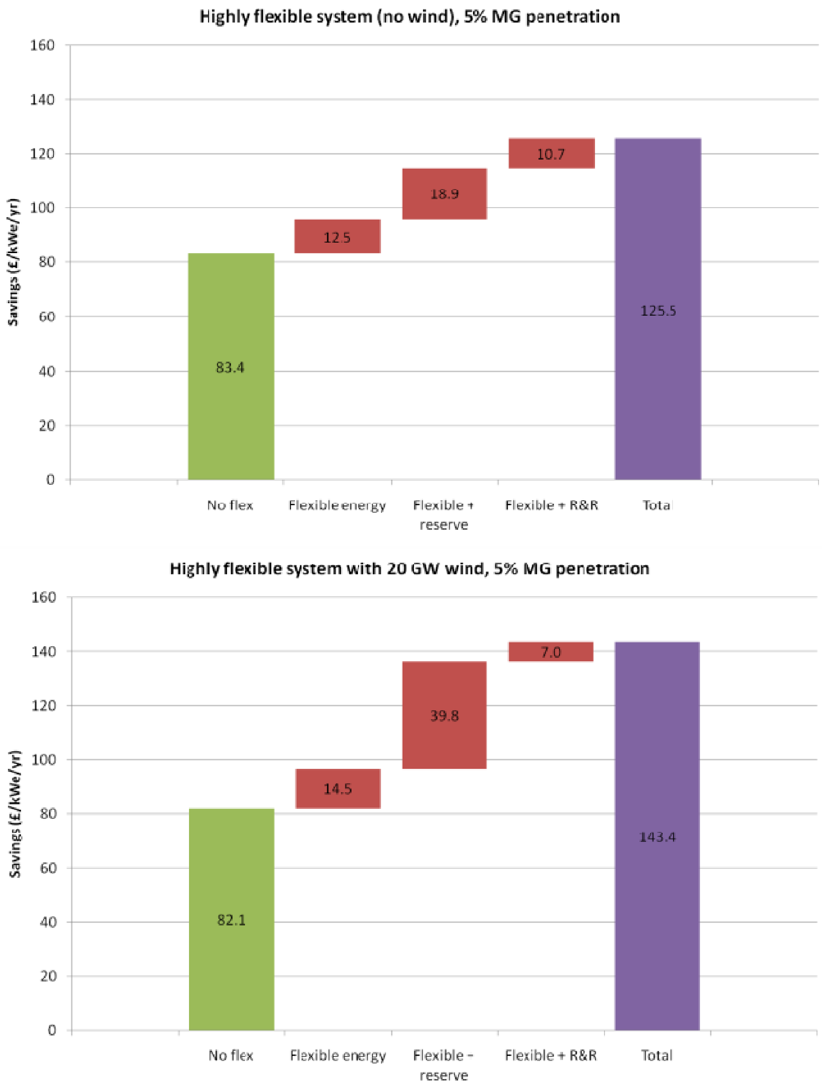

Figure 4.21. Incremental components of system savings for the highly flexible system

Figure 4.22 depicts a similar behaviour for the medium flexible system. The overall level of savings is lower (due to lower assumption on generator fuel cost), but the weight of the components is comparable to the highly flexible case.

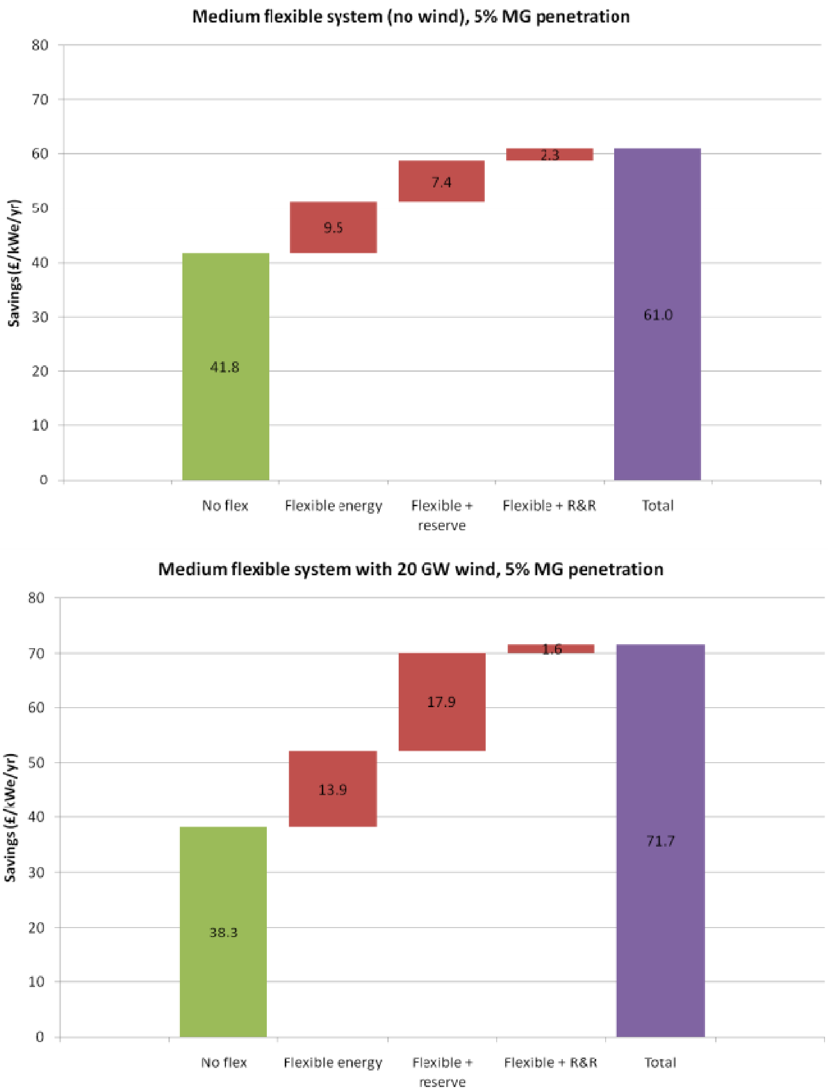

Figure 4.22. Incremental components of system savings for the medium flexible system

Finally, in the low-flexibility system, as indicated in Figure 4.23, the majority of the value comes from providing reserve services. Flexible reserve provision is of great value in this kind of system, since it has a lot of relatively inexpensive energy, but little operating flexibility.

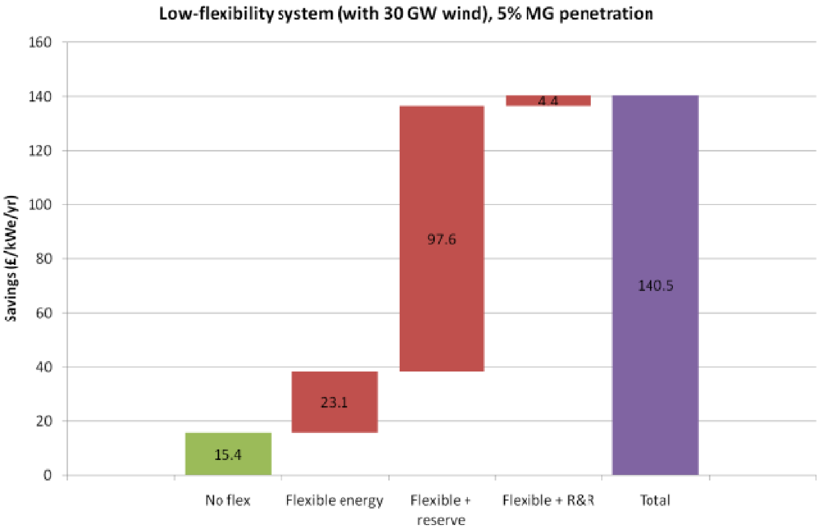

Figure 4.23. Incremental components of system savings for the low-flexibility system

It must be highlighted that certain cost saving figures as obtained from the analysis may seem rather attractive, and are a direct consequence of the potential of exploiting highly flexible small scale systems with an equivalent low production cost owing to cogeneration discounting. However, the potential savings need to be balanced against costs that would need to be incurred in order to enable the Microgrids to provide operational flexibility.

In particular, in order to provide flexible energy balancing within a day, micro-CHPs need to be equipped with appropriate storage devices. Cost of installing and maintaining storage facilities needs to be compared to the potential savings that could be achieved from providing flexible electricity generation to accommodate the needs of the system. Alternatively, auxiliary boilers could be installed, in which case both investment cost and operational cost of the overall cogeneration system (micro-CHP plus boiler) would increase, since the benefits from cogeneration gas discounting (which is relevant to both cost and emission) would decrease.

Similarly, if a micro-CHP needs to provide reserve and frequency response, it needs to be fitted with adequate real-time communication and control equipment, which would allow it to flexibly respond to automatic or instructed commands from the system operator.

Therefore, as in the previous cases analysed in the previous chapters, a full CBA need to be run in order to indicate whether using controllability option would provide net overall benefits. In particular, the cost of additional equipment such as storage, auxiliary boilers, communication systems, and so forth, together with potential additional costs, need to be lower than the projected benefits, in order for these operating regimes to become economically justifiable.

4.4.7 Estimate of cost savings for conventional generation displacement

Using Microgrids replaces a portion of electricity otherwise generated by conventional units, but it also reduces the need for conventional capacity in the system. In the analysis carried out here, this impact was estimated by observing the maximum utilised conventional capacity within one year in cases with and without Microgrids being used in the system. The difference between the two cases then provides a rough estimate of how much conventional capacity could be displaced if Microgrids operated in a particular regime at a particular penetration level.

Studies performed for different system types indicated that no significant discrepancies exist in terms of how much conventional capacity could be displaced by Microgrids. Therefore, the results shown in the following figures refer to all system types.

Figure 4.24 indicates how much capacity the Microgrids could displace in a system with no wind, for a range of operating regimes and Microgrid penetrations. The displacements are shown along with the actual total capacity of micro-CHPs, for the sake of comparison. According to the figure, the inflexible operating mode of Microgrids is only able to displace a part of the installed micro-CHP capacity (some 45-60% of it, depending on the penetration), with larger penetrations displacing relatively less capacity due to the saturation effect. When flexible energy provision by Microgrids is introduced, the displaced capacity increases approximately to the level of installed micro-CHP capacity. This is mainly because in this regime the flexibility of Microgrids allows for the flattening of the load diagram seen by conventional units, i.e. reducing the net peak to be covered by large-scale generators.

Adding further flexible services to Microgrids, although improving the economic and environmental performance of the system, does not seem to displace any further conventional capacity (most of the displacement potential has already been exhausted by allowing for flexible energy provision).

In a system with 20 GW of wind, as suggested by Figure 4.25, the capacity displaced would change only marginally compared to the no-wind case. It would again reach roughly the level of installed micro-CHP capacity for the flexible operating regimes of the Microgrids.

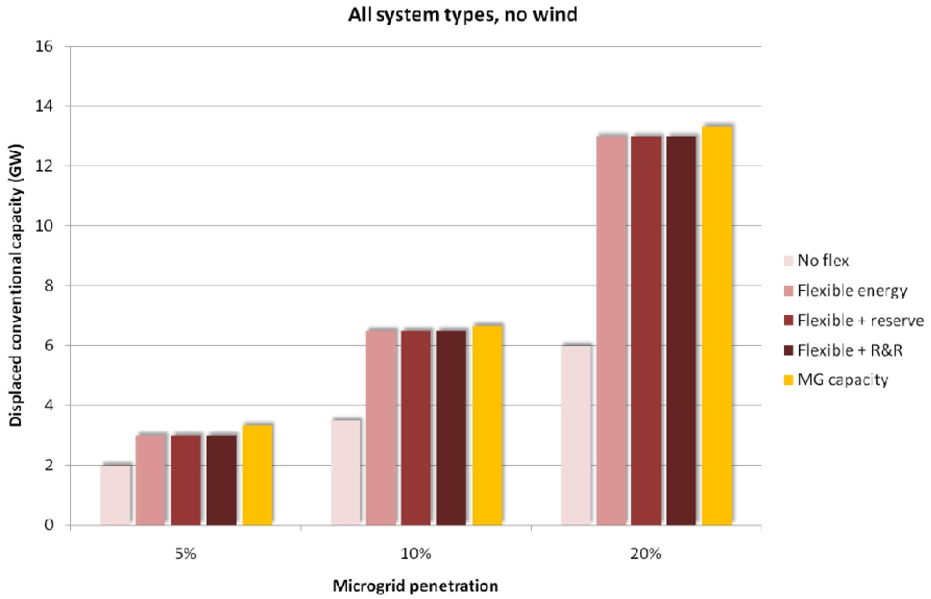

Figure 4.24. Displaced conventional capacity as a result of using Microgrids in systems without wind

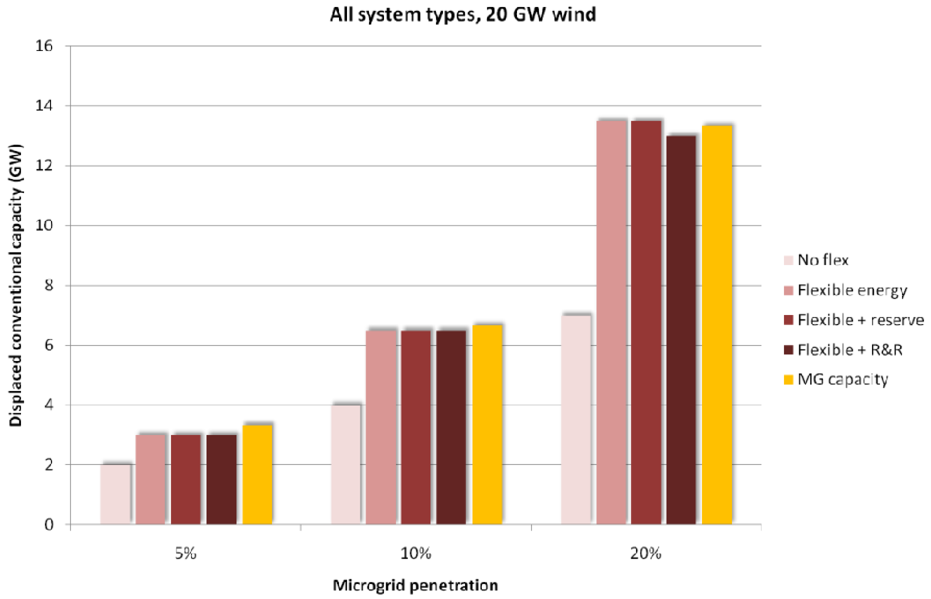

Figure 4.25. Displaced conventional capacity as a result of using Microgrids in systems with 20 GW wind

A further economic estimate based on the computed conventional generation capacity that is displaced by Microgrids can be carried out. However, again it is not straightforward to move directly from displaced capacity to economics, mainly because investments in generation are no longer a centralized issue but depend on several factors related to promoters, market, etc. Nevertheless, just to give an idea of the economic magnitude of the benefits, in order to put this effect of displacing conventional capacity in perspective with operating cost savings, the investment cost that would be needed to construct the displaced capacity has been annualised and divided with total installed micro-CHP capacity. This makes it possible to monetise the capacity displacement, and to express it relative to Microgrid electrical capacity again, in a similar fashion to operational benefits discussed earlier.

The investment cost avoided now differs between highly flexible and medium flexible systems, since different investment costs were assumed for the two types of conventional generation units. The overnight investment cost for the highly flexible units was supposed to be £630/kW with a life time of 25 years, while the medium flexible units were assumed to cost £1180/kW with expected life time of 40 years. Assuming 7% for the discount rate, the annualised investment cost for the two technologies would then be equal to £54/kW/yr (highly flexible units) and £89/kW/yr (medium flexible units).

With the above cost assumptions, the avoided annualised investment cost for a range of Microgrid penetrations and operating regimes is shown in Figure 4.26 and Figure 4.27. For the *highly flexible system*, annual savings in investment costs are between £25 and £32/kWe for the inflexible regime, and around £50/kWe for flexible operating regimes. The specific savings per kilowatt of electrical capacity do not change significantly with different Microgrid penetrations. Again, no marked discrepancies occur between cases with and without wind.

In the *medium flexible system* cost savings are higher due to the higher investment cost assumption. Inflexible operating regime in this case brings between £40 and £52/kWe of savings in annualised investment cost, while flexible regimes achieve between £80 and £90/kWe of avoided cost. The same level of avoided investment cost as in the medium-flexibility case would be obtained for the *low-flexibility* case, and is therefore not shown separately.

The level of savings achieved through avoiding the cost of building conventional capacity is considerable and of similar order of magnitude as savings in operating cost. These capital cost savings would obviously need to be compared to installation cost of micro-CHPs to obtain a correct picture of net benefits with respect to investments in capacity. Without going into detail of this comparative analysis, the order of magnitude of the findings suggests that conventional generation capacity could be economically displaced by Microgrids. In particular, the value of the displaced capacity could change significantly if Microgrids can provide system services, so that in this sense the CBA analysis of centralised towards decentralised energy is a function of the level of additional flexibility that can be brought by DG.

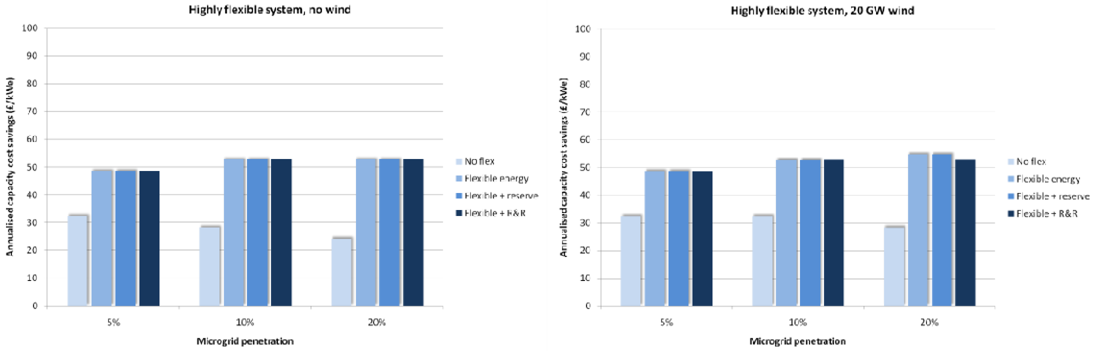

Figure 4.26. Annualised savings in investment cost of displaced conventional capacity for the highly flexible system

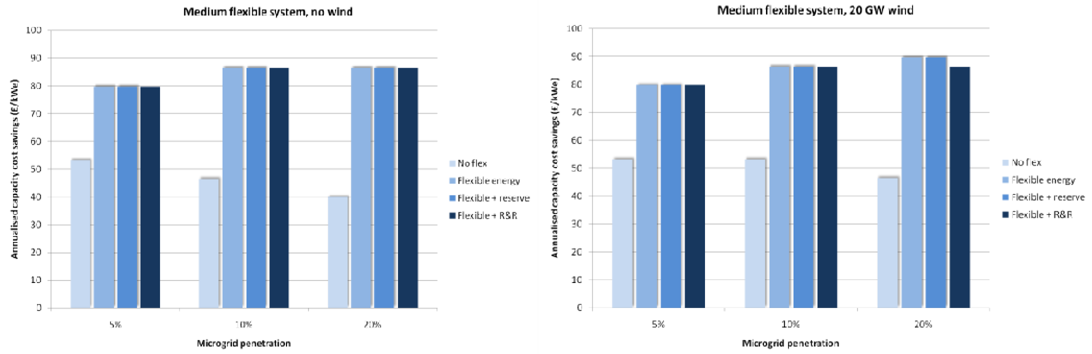

Figure 4.27. Annualised savings in investment cost of displaced conventional capacity for the medium flexible system

Conclusively, it needs to be stressed that this estimate is rather rough, and in order to obtain better estimates a detailed capacity adequacy analysis would be necessary. This would need to include the availability performance of conventional generation, as well as of micro-CHPs, which were assumed to be 100% reliable in this analysis. In other words, the results presented here are likely to err slightly on the optimistic side. Nevertheless, they can still provide a reasonable first estimate of the impact of different regimes of Microgrid operation on the capacity needed from the rest of the system.

4.4.8 Conclusive remarks on system-level impact of Microgrids

Based on the results shown above, there is significant potential for Microgrids to contribute to a more economical and sustainable operation of current electricity systems. They can provide these benefits through either providing cleaner and less expensive electricity, or providing flexible system services such as balancing, reserve and response.

One of the key drivers for reaping benefits from Microgrids is its operation cost, or more precisely, the differential between its cost and the cost of alternative large-scale generation in the system. Obviously, with cheaper electricity generated by Microgrids, the value it provides to the system grows larger.

Another key driver for the value of Microgrids is the flexibility of the system they are embedded into. This refers to both the flexibility of the conventional generation predominating in the system, and the share of must-run or intermittent renewable generation. With these shares reaching non-negligible levels the value of Microgrids, in terms of providing flexibility-related services such as reserve and response, increases rapidly.

Lastly, Microgrids have the potential to displace not only the energy produced by conventional plants, but also some of their capacity. This analysis, although quite approximate, suggests that Microgrids operating in *flexible regimes* are capable to displace conventional capacity in the amount roughly equal to installed micro-CHP capacity.

4.6 Final considerations on Microgrids impact on conventional generation operation and development

Different analyses have been performed in this Chapter to address the impact and the benefits brought by Microgrids with respect to the conventional generation system.
More specifically, two general types of analysis have been carried out, namely, relevant to identify the (long term) potential of Microgrids to provide generation adequacy while keeping given level of reliability, and to identify the value of Microgrids if capable to provide load balancing ancillary services to the system.

In terms of capacity adequacy, the detailed modelling and analysis performed in the Portuguese case confirms the previous network analyses of Chapter 2, whereby the main driver for benefits is the correlation between micro-DG supply and (peak) demand. This leads to relatively high value of capacity credit for micro-CHP, in the order of 60%, which is consistent with values obtained in the UK analysis for similar penetration levels. On the other hand the CC values of the PV and micro-wind systems are quite limited, namely, 16% and 4%, respectively. Another key conclusion from the results is related to the limited influence that the rated power and unavailability of the micro-generators has on the CC value.

Regarding more specifically Microgrids, the results show that the integration of controllable micro-CHP systems within MG increases their CC, for example passing from 69% to 75% if 20% of these generators may be controlled by the action of Microgrids. Similarly, significant CC may be obtained by load controllability within Microgrids. For instance, the control of 5% of the total system load enables to remove roughly 5% of the conventional generation capacity installed in the system. This confirms the strategic role that DSM actions enabled by aggregating Microgrids could play in future system development.

In terms of operational analysis, a detailed scheduling model developed by Imperial has been used to quantify the potential value of Microgrids in providing system-level services and benefits. In particular, different levels of balancing services have been analysed within different generation portfolio flexibility frameworks, in order to understand the conditions whereby benefits would arise. By looking at the incremental value brought by adding flexible service capabilities to Microgrids operation, for highly flexible system with 5% penetration rate of Microgrids the majority of the system value is contributed by using electricity from micro-CHPs in the first place. The reserve component of the value becomes significant in case with higher wind penetration, due to higher reserve requirements to conventional generators in such conditions that are displaced by micro-CHP.
For a medium flexible system, the overall level of savings is lower (due to overall lower fuel cost from the generation portfolio), but the weight of the additional value components for system services provision is comparable to the highly flexible case.

In the low-flexibility system, the majority of the value comes from providing reserve services. Indeed, flexible reserve provision is of great value in this kind of system, since the generation portfolio exhibits relatively inexpensive energy, but very little operating flexibility. This additional flexibility also allows higher deployment of intermittent renewable sources. In fact, while an inflexible operating regime (i.e. heat load following) for micro-CHPs can actually exacerbate the volume of wind curtailed to provide system balancing, the situation improves slightly with adding balancing flexibility to Microgrids, and a major improvement appears when Microgrids are allowed to provide reserve services (and replace reserve provided by conventional units). In this regard, controllability of small-scale flexible units do not only provide a cheaper alternative to conventional generators to provide flexibility, but also allows larger integration of renewable sources.

From the scheduling analysis carried out it has emerged how Microgrids have the potential to displace not only the energy produced by conventional plants, but also some of their capacity. In particular, while the capacity displaced for inflexible regimes (i.e., heat following mode for CHP) is in the same order of magnitude of the capacity credit as computed from security models, the results, although approximate, suggest that Microgrids operating in *flexible regimes* are capable to displace conventional capacity in the amount roughly equal to the installed micro-CHP capacity.

In terms of economic savings attached to conventional generation capacity displacement, the level of savings achieved through avoiding the cost of building conventional capacity is considerable and of similar order of magnitude as savings in operating cost. These capital cost savings would obviously need to be compared to installation cost of micro-CHPs to obtain a correct picture of net benefits with respect to investments in capacity. Without going into detail of this comparative analysis, the order of magnitude of the findings suggests that conventional generation capacity could be economically displaced by Microgrids. In particular, the value of the displaced capacity could change significantly if Microgrids can provide system services, so that in this sense the CBA analysis of centralised towards decentralised energy is a function of the level of additional flexibility that can be brought by DG.

5. Concluding remarks on Task TH2 of WPH

This report has described the results of the investigations performed in WPH, Task 2 of the *MORE MICROGRIDS* Project.

The overall objective of the Task has been to quantify the impact of Microgrid scenarios on investment and replacement strategies of future national electricity infrastructure across Europe.

To these purposes, a number of models and tools have been developed and relevant studies have been conducted by several partners led by Imperial to investigate the potential impact and benefits of Microgrid operation on different power system areas of interest. More specifically, the impact of various Microgrid scenarios with uncontrolled and controlled DG and loads has been analysed for the development of:

- Distribution networks;
- Transmission networks;
- Centralised conventional generation.

For distribution networks, a number of typical networks, representative of different types of distribution systems it is possible to encounter across Europe, have been analysed, namely, for FYROM, Germany, Greece, Italy, Netherlands, Poland, Portugal, and UK. Notwithstanding the differences in the models used as well as in the types of networks and load and generations scenarios envisaged by the partners, the results found convey the basic information that distributed generation embedded in Microgrids enabling some sort of generation/load controllability can bring substantial benefits for the development of distribution infrastructures. Such benefits tend to be more apparent in the presence of relatively weak networks and extreme situations such as high load/low DG and low load/high DG, as quantified in the different studies performed, with the main driver for benefits being the correlation between local supply and demand. In addition, distributed generation in Microgrids is capable to bring further environmental benefits owing to the possibility of integrating small-scale renewable resources such as PV or high efficiency cogeneration systems through micro-CHP.

For transmission networks, it has been shown how local generation can support congestion relieves and capacity release and can thus contribute to a more economic efficient system development. Controllability of transmission flows through aggregated DG enabled by Microgrids can bring further benefits although to a limited extent, since the great majority of flows are still controlled by conventional units. In addition, spot benefits may arise from deployment of controllable loads that, besides helping release capacity and reduce congestion volumes, with overall economic benefits in terms of energy cost, can contribute to additional integration of intermittent and clean renewable sources such as wind.

In terms of impact on conventional generation, the findings from the studies highlight how benefits in terms of operational cost of the system arise owing to local generation correlated with demand (e.g., micro-CHP in northern countries). In addition, if DG controllable within Microgrids can provide system services such as energy flexibility, reserve and response, the overall benefits get substantial, above all in the presence of relatively inflexible systems with nuclear and CCS plants as well as intermittent wind power. In this respect, the flexibility provided by Microgrids can help further integration of renewable and clean sources while mitigating the cost for additional spinning and standing reserve from conventional power plants. This can also contribute to reduction of installed conventional generation capacity. In this regard, the economic analyses run with the developed scheduling model lead to similar conclusions in terms of capacity credit from Microgrids as obtained from more advanced security of supply models. In particular, with both approaches, the possibility of controlling generation/load can increase the capacity contribution from distributed energy sources.

The analyses carried out in this work have highlighted the value of Microgrids for the system according to the different areas explored above. Such benefits need to be assessed against the cost of installing microgrids, namely, provided that DG is already in place, the cost of communication, responsive automatisms, additional equipment needed for efficient operation (e.g., heat storage systems allowing decoupling heat and electricity production), and so forth. In addition, a pre-requisite for the effective development of Microgrids, and for such benefits to manifest, is that adequate commercial and regulatory frameworks are in place to acknowledge the system benefits found. This aspect is discussed in Deliverable DH3.

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