Distributed Generation Operation in an Islanded Network

Final Report
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# Table of contents

1 Introduction 1

2 Task A.1: Inventory of the installed base of Distributed Generation (<5 MW) in the GB power system 3
   2.1 Installed Capacity of Distributed Generation 3
   2.2 Data coverage and geographical distribution 7
   2.3 Composition of the DG fleet per technology 9

3 Task A.2: Technology specific issues and implications for system operation 11
   3.1 Loss of main detection 11
      3.1.1 Fundamental considerations 11
      3.1.2 Loss of Mains detection in current codes (ER G59 and ER G83) 13
   3.2 Survey of manufacturers 15
   3.3 Characteristics per technology 16
      3.3.1 Wind onshore 17
      3.3.2 Photovoltaics 19
      3.3.3 Gas engines and biomass 20
      3.3.4 Hydro and Wave 23
      3.3.5 Dedicated RoCoF relays 23
   3.4 Summary technology review 25
   3.5 Cost indicators for retrofit activities 27

4 Task A.3: International Experience 29
   4.1 European background and related developments 29
   4.2 Germany 29
   4.3 Netherlands 31
   4.4 Ireland 33
   4.5 United States 34

5 Conclusions and recommendations 36
   5.1 Conclusions 36
   5.2 Recommendations 38
   5.3 Potential need for retrofit activities and related cost 38

6 Appendix 40
   6.1 Classification of used datasets and the quality of information derived 40
   6.2 Sanity check data bases 42
   6.3 Update: Estimated growth of DG below 5 MW since end of 2013 43
   6.4 System stability versus LOM protection – contradicting requirements? 44
6.5 Retrofit programmes in Germany – characteristics and experiences
1 Introduction

During the last decade, the power system in Great Britain has witnessed a sharp increase in the supply of electricity from distributed generation (DG). In addition, there is a trend towards generation from renewable sources (RES-E). Much of this generation is power electronic converter controlled and therefore does not naturally contribute to the system inertia. Furthermore, as converter controlled generation begins to displace directly connected synchronous (or induction) generation, a net decrease in system inertia is expected\(^\text{1}\). This trend has been observed during recent years already (see Figure 1).

\[
\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure1}
\caption{Decreasing trend in inertia in the GB power system (source: ‘Frequency Changes during Large Disturbances and their Impact on the Total System’, Energy Networks Association / National Grid, May 2014)}
\end{figure}
\]

With less inertia on the system, the ability to contain frequency deviations caused by large losses in load or generation becomes more onerous. Furthermore with less inertia, the rate of change and magnitude of frequency deviations for the same disturbance is larger.

Much of the DG in Great Britain uses rate of change of frequency (RoCoF) as loss of mains protection with the aim of disconnecting the plant quickly from the main system at a remote point should the generator (or the surrounding network) become isolated. This protection operates on the assumption that any island which is sustained will contain a large supply-demand imbalance, and therefore frequency will deviate quickly (i.e. with a large rate of change). This rate of change is detected by the

RoCoF relay, and the plant is disconnected to ensure protection of all assets and personnel in that island, particularly if auto-reclose is employed in that network. If the rate of change of frequency caused by a system-wide frequency disturbance increases because of lower system inertia, it is possible that RoCoF protection will be inadvertently triggered for a smaller event of a system-wide frequency disturbance. This has the potential to substantially increase the risk of low frequency demand disconnection, and in the worst case, potential frequency instability. The view is that relaxing the current RoCoF trip settings is one method to reduce the system wide risk of demand disconnection and frequency instability.

The GB system operators have assessed the potential risk of generation units with a capacity of 5MW and greater disconnecting as a consequence of system-wide frequency excursions\(^2\). As a result, the joint Grid Code and Distribution Code working group concluded that the requirements for RoCoF protection settings for this group of DG need to be relaxed in terms of intensity and duration of frequency excursions\(^3\). Phase 2 of the working group remit is to review the RoCoF setting for DG with an installed capacity of less than 5 MW. Ecofys has been contracted to assess the numbers and types of distributed generators in Great Britain, their ability to withstand a frequency deviation and their stability in islanded operation.

This report presents the results of the analysis. The focus is on

- An inventory of the installed base of DG (<5 MW) in the British power system (Task A.1);
- Technology-specific issues, implications and costs for DG operation with relaxed RoCoF settings (Task A.2); and
- An evaluation of relevant international experience (Task A.3)

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\(^2\) University of Strathclyde (2013): Assessment of Risks Resulting from the Adjustment of RoCoF Based Loss of Mains Protection Settings – Phase I

\(^3\) Energy Networks Association (2013): Frequency Changes during Large Disturbances and their Impact on the Total System
2 Task A.1: Inventory of the installed base of Distributed Generation (<5 MW) in the GB power system

2.1 Installed Capacity of Distributed Generation

The objective of this part of the study is to assess various databases to provide a robust picture of the composition of the population of various DG technologies in Great Britain. The purpose of this analysis is to support the evaluation of the potential impact of particular technologies and plant sizes on the operation of the GB power system. To this end we have to make sure that the overall numbers are complete and correct. Therefore we compared and validated different datasets to create a consistent inventory of small distributed generation (<5 MW). We compiled acknowledgeable data with reasonable effort. Information on geographical distribution of DG or network configurations is not necessarily required in this part of the study.

During the last decade, growth of DG and RES-E has been stimulated by regulatory instruments like the Renewables Obligation (RO) and Feed-In Tariff scheme (FITs) for small-scale and low-carbon electricity generation technologies, combined with the strong reduction of electricity generation costs of these power units.

To estimate the installed capacity and to characterise the power fleet in GB, we used different sources. (For a detailed description of data sources and their limitations see 6.1 in the appendix). The inventory of power units with at least 5 MW is based on the public reports from DUKES, Renewable UK and EPIA. The quantities of power units below 5 MW are based on the public registers from Ofgem. At the end of 2013, the installed capacity of all power units in GB was less than 90 GW. With an installed capacity of up to 20 GW, more than 20% of the whole population was attributed to renewable energy sources (RES). Of this amount, the total capacity of DG with unit size less than 5 MW is approximately 5 GW. These distributed generators mainly feed in to the low- or medium-voltage distribution network. With the increase of generation capacity shown in Figure 2, RES and small power units with less than 5 MW reached an increasing systemic importance, also in the context of operating the transmission network.

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4 Work stream B running in parallel to this research focuses on the behaviour of DG arrangements in distribution networks. Calibration of respective models and experimental setups does require information on common configurations and combinations of DG in existing distribution networks. Hence, work stream B relies to a significant extent on information from individual DNOs. In contrast to this part of the study, the underlying datasets in work stream B do not have to cover the complete population or GB. Datasets of single DNO’s may be sufficient as long as they are representative for the other parts of the country.


8 https://www.renewablesandchp.ofgem.gov.uk/

9 For this quantity onshore wind farms with at least 5 MW and all offshore wind farms are excluded.
Comparing the development of the installed capacity in Figure 2, small power units (< 5 MW<sub>e</sub>) have a share of 20% to 25% of all RES.

To specify the terminology of small DG (< 5 MW<sub>e</sub>) we used the following classification:

- **Wind onshore**, individual wind turbines or wind farms with a maximum installed capacity of less than 5 MW and at least 0.1 MW<sup>10</sup> at the connection point
- **Photovoltaic**, PV power units with a maximum installed capacity of less than 5 MW at the connection point
- **Gas and Bio**, DG with gas or biomass as energy source and with a combustion engine or a turbine under the investigated support schemes<sup>11</sup> and a maximum installed capacity of less than 5 MW<sup>12</sup> at the connection point
- **Hydro and Wave**, DG with hydro and ocean energy as a source under the investigated support schemes<sup>13</sup> and a maximum installed capacity of less than 5 MW at the connection point

As it can be seen clearly in Figure 3, the installed capacity of small power units (< 5 MW<sub>e</sub>) is distributed unevenly between different technologies. For example, almost 80% of Photovoltaic installed generating capacity is less than 5 MW in unit size, whereas the majority of hydro and wave generating capacity comprises installations is greater than 5 MW in size. The share of small units (< 5 MW<sub>e</sub>) for hydro and wave are thus just 15% of total capacity in that sector. The quantity of small wind onshore plants is explained due to the defined unit size. To classify the DG in smaller than

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<sup>10</sup> The quantitative analysis is mainly based on the datasets from Renewable UK, where small wind turbines are not registered in the public databases. According to the market report and the Ofgem datasets at the end of 2013 more than 100 MW and up to 7,000 units of small wind turbines (less than 100 kW) were installed. Further assumption on this are described in chapter 6.1.

<sup>11</sup> In the analysis we considered the following instruments: Renewables Obligation (RO), Renewable Energy Guarantees of Origin scheme (REGO), Climate Change Levy (CCL) and Feed-In Tariff scheme (FITs). In general power units with less than 5 MW are registers for one of these support schemes.

<sup>12</sup> Electric power

<sup>13</sup> In the analysis we considered the following instruments: Renewables Obligation (RO), Renewable Energy Guarantees of Origin scheme (REGO), Climate Change Levy (CCL) and Feed-In Tariff scheme (FITs).
5 MW and at least 5 MW, we analysed the maximum installed capacity at the point of common connection. Therefore most of the wind farms do not belong to the class of small DG.

Table 1 and Figure 4 give an overview of the detailed quantity of small DG (< 5 MW) for each technology and per voltage level. More than 50% of the capacity of small DG (< 5 MW) are photovoltaic units\(^\text{14}\). Generation technologies based on gas or biomass have a share of nearly 25%. Regarding the numbers of power units, about 520,000 photovoltaic units represent more than 99% of the population. There are just about 1,000 units for each other type of technology considered here.

Table 1 Overview on the DG fleet with less than 5 MW at the end of 2013

<table>
<thead>
<tr>
<th>Technology</th>
<th>Installed capacity in MW</th>
<th>Number of investigated/registered power units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Sum</td>
<td>HV</td>
</tr>
<tr>
<td>Wind turbines</td>
<td>700</td>
<td>550</td>
</tr>
<tr>
<td>Photovoltaic</td>
<td>2,600</td>
<td>750</td>
</tr>
<tr>
<td>Gas + Bio</td>
<td>1,100</td>
<td>1,080</td>
</tr>
<tr>
<td>Hydro + Wave</td>
<td>250</td>
<td>210</td>
</tr>
</tbody>
</table>

\(^\text{14}\) The figures represent the situation at the end of 2013. Since then the installed capacity of distributed generation below 5 MW grew significantly. For an update see appendix 6.3.

\(^\text{15}\) The quantitative analysis is mainly based on the datasets from Renewable UK, where small wind turbines are not registered in the public databases. According to the market report and the Ofgem datasets at the end of 2013 more than 100 MW and up to 7,000 units of small wind turbines (less than 100 kW) were installed. Further assumption on this are described in chapter 6.1.
Figure 4 Overview on the DG fleet per voltage level (HV: high voltage level, LV: low voltage level) below 5 MW, year: end of 2013, sources: Ecofys, based on DUKES, Renewable UK, EPIA and Ofgem
2.2 Data coverage and geographical distribution

In order to verify plausibility of the data we analysed the geographical distribution within GB. We used OFGEMs FIT register in order to analyse the geographical distribution of PV plants. FIT data cover approximately 2,000 MW with valid ZIP code information. Covering nearly 75% of the installed capacity of 2,600 MW this data set may be considered being representative for the plant population across the country. Figure 5 illustrates the distribution of small photovoltaic units (< 5 MWel) in GB\textsuperscript{16}. Regions with high amounts of photovoltaics are concentrated in South and East England.

\textbf{Figure 5 Estimated allocation of Photovoltaic Generation in Great Britain per NUTS 3 region, year: end of 2013}

The allocation of the installed capacity of various technologies differs significantly in each geographical region. Up to 80\% of the total DG capacity in GB is installed in England, consisting mainly of Photovoltaic and Gas/CHP + Bio (see Figure 6). In Scotland, there is 700 MW installed in total with an installed capacity of wind and hydro being 500 MW. Scotland is dominated by Wind onshore and Wales shows a high share of PV.

\textsuperscript{16} Based on the postal code, we aggregated the installed capacity for each Nuts-3 Region. - Nomenclature of Territorial Units for Statistics (NUTS) on level 3 represents Areas of Upper or lower tier authorities (England), Council Areas or Islands Areas (Scotland) and Principal Areas (Wales)
Figure 6 Distribution of small DG (≤ 5 MW_{el}) among England, Scotland and Wales (left) and per technology (right), year: end of 2013, sources: Ecofys, based on DUKES, Renewable UK, EPIA and Ofgem.

Especially for photovoltaic with less than 5 MW_{el} the FIT register provides basic information for the majority of the population. But due to the scope of the FIT scheme, the FIT register is quite incomplete regarding other DG technologies. In addition, technical and geographical information of the FIT register is limited. Related to wind, bio/CHP and hydro/wave no reliable geographical information can be drawn from this source. Most of the other datasets do not contain detailed geo-references.

In order to verify correctness of the GB datasets we used the registers provided by the DNOs for a sanity check of data (see section 6.1 in the Appendix).

The analysis supports the validity of the compiled data for the whole GB system.
2.3 Composition of the DG fleet per technology

Based on the consolidated and classified data of the various sources, we created a unit based dataset for each technology to analyse the spread of power ranges. This analysis describes the characteristics of the generation fleet for each technology.

As illustrated in Figure 7, the unit sizes of individual wind turbines and small wind farms (total capacity of 700 MW) is fairly evenly distributed between 0.2 MW and 4.6 MW. However, clusters can be identified at the power ranges of around 0.45 MW, 2 MW and 4 MW, which is related to the standard manufactured wind turbine sizes and applied rates of the support schemes for different power classes. The cumulated share for individual units and small wind farms with a power class of up to 1 MW is around 30%.

![Figure 7 Allocation of the power class for wind farms along their cumulated installed capacity, year: end of 2013, source: Ecofys](image)

In contrast to wind, the total capacity of PV (2600 MW) is made up mainly of small power units (< 5 MW). Unit sizes start with less than 0.001 MW and go up to 5 MW. More than 50% of the cumulated capacity are units less than or equal to 0.004 MW in size, and 73% are units less than or equal to 1 MW. Few units fall in the power range between 1 MW and 3 MW, and the cumulated capacity of units between 3 MW and 5 MW have a share of more than 20%. The clusters highlighted in the Figure 8 are mainly related to the applied rates of the support schemes.
Figure 8 Allocation of the power class for PV in linear (left) and logarithmic scale (right) along their cumulated installed capacity, year: end of 2013, source: Ecofys

Similar to the wind power units, gas and bio based power units (which are the second largest fleet with total capacity 1100 MW) do not show dominating ranges of unit capacity. Unit sizes are evenly distributed between less than 0.001 MW and 5 MW. The cumulative share of units up to 1 MW is around 20%.

The allocation curve of hydro and wave (300 MW) in Figure 9 is separated into two parts. The first part of the graph is almost linear. Between less than 0.001 MW and 1.5 MW, up to 60% of the cumulated installed capacity is distributed evenly. Afterwards, clusters exist at certain power ranges, like 2 MW and 4 MW. As the share of units with a power range of less than 1 kW is 50%, the fleet is characterised by many really small power units (< 5 MWel).

Figure 9 Allocation of the power class for gas and bio (left) and hydro and wave (right) along their cumulated installed capacity, year: end of 2013, source: Ecofys
3 Task A.2: Technology specific issues and implications for system operation

3.1 Loss of main detection

3.1.1 Fundamental considerations

Loss of mains (LOM) or anti islanding detection methods have to prevent the forming of islands in local distribution grids in case of the upstream network being disconnected due to a fault. Unintended sustained electrical islands are associated with serious safety risks. They may cause health and safety risks for the utility personal in the vicinity of the island; may jeopardise the power quality to the customers’ equipment in the formed island, and might damage the islanded generation plants or network assets if they are reconnected without balanced synchronisation.

The methods to detect LOM can be categorised as remote and local methods. Intertripping is an example for a commonly applied and very effective remote method. However, intertripping is not economically viable in complex network topologies and with highly dispersed generation, e.g. for residential PV systems. For that reason, distributed generation relies on local methods to a high extent. Local methods evaluate the observed network characteristics at the terminals of the generation plant or point of common coupling.

Further, active and passive LOM methods can be distinguished. Passive methods are based on monitoring one or more system parameters, like frequency or voltage phase, and comparing them with respective tolerances. Active methods continuously manipulate the output of DG and base their decision on the systems’ response to small disturbances injected into the network. Active methods are regularly claimed to be more effective and robust than passive methods. However, they may affect power quality and, hence, application is restricted, depending on the country specific network codes.

In practical applications, LOM protection is dominated by passive local methods due to their simplicity and low cost. Some common LOM methods are described below.

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17 Recently, a research project on the comparative merits of different LOM detection and anti-islanding mechanisms in distribution networks with increased shares of DG has been started at the Helmut Schmidt University of the Federal Armed Forces, Hamburg – Germany. Results are expected at the end of 2015.

The study has been contracted by the Forum network technology / network operation in the VDE (FNN). The FNN is responsible for drafting technical codes in Germany. Aim of the study is to provide the knowledge required for further development of the distribution codes.

Active Methods

- **Frequency (or Phase/Voltage) shift**: The method applies only to inverter-connected DG. The idea is to inject a small perturbation in the form of a phase shift. As long as the inverter is connected to a strong network the frequency is maintained by the power system. In case the system is islanded, the inverter may succeed in gradually shifting the frequency. If the preset tolerances are exceeded, the inverter will trip. Of course, the effectiveness of the mechanism strongly depends on the power share of the inverter in the island. No dedicated standard exists how to realise frequency shift algorithms and manufacturers provide limited information on their proprietary solutions. There is some de facto consensus on the general method: the algorithm tries to increase frequency in case of overfrequency and to decrease it in case of underfrequency. Currently, the UK codes ER G59\(^{18}\) and ER G83\(^{19}\) do not explicitly restrict application of this method.

- **Reactive power export error**: DG injects a level of reactive power at the point of common coupling. It is only possible to simultaneously maintain this reactive power balance AND voltage levels as long as the DG is grid connected. Application of this method is limited as soon as technical codes specify a certain behaviour regarding power factor, reactive power and / or voltage control. Currently, this is the case in most countries. Also the UK codes ER G59\(^{20}\) and ER G83\(^{21}\) effectively restrict application of this method.

- **System impedance monitoring**: LOM is detected by actively monitoring the system impedance. For that a high frequency source is connected via a coupling capacitor at the interconnection point. When the systems are synchronised, the high frequency ripple at coupling point is negligible. If island appears, the high frequency signal is clearly detectable and generator trips. UK codes do not allow application of these methods\(^{22}\).

Passive Methods

- The simplest method is measuring **absolute values of voltage and frequency** and comparing them with the given (narrow) tolerances. This method has been widely used for DG connected to the distribution systems, e.g. in continental Europe. Recent studies questioned the effectiveness and appropriateness of this method in power systems with high shares of DG and highlighted potential conflicts with extended system requirements (low voltage fault ride through, extended frequency ranges also applicable to DG in distribution networks)\(^{23}\).

- **Rate of change of frequency (RoCoF)**: The inertia of interconnected systems is substantial and, hence, in interconnected operation system frequency is steady or changes slowly. Enhanced frequency gradients, in turn, are interpreted as a reliable indicator for islanded operation. The RoCoF value is derived from voltage measurements. The estimated value is compared to pre-set thresholds.

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\(^{18}\) Engineering Recommendation G59, Issue 3 Amendment 1 August 2014, section 9.3.4
\(^{19}\) Engineering Recommendation G83, Issue 2 December 2012, section 5.6
\(^{20}\) Engineering Recommendation G59, Issue 3 Amendment 1 August 2014, section 9.3.4
\(^{21}\) Engineering Recommendation G83, Issue 2 December 2012, section 5.6
\(^{22}\) Engineering Recommendation G83, Issue 2 December 2012, section 5.3.2
\(^{23}\) [https://www.vde.com/de/fnn/arbeitsgebiete/studien/seiten/fehlerfall.aspx](https://www.vde.com/de/fnn/arbeitsgebiete/studien/seiten/fehlerfall.aspx), Summary in English available on request at VDE / FNN.
• Voltage Vector Shift: The method detects a jump of the voltage phase (phase error) in subsequent cycles. The underlying assumption is that in an interconnected system the phase angle cannot change in a disruptive manner. If the phase difference exceeds a pre-set threshold this is considered being an indicator for island operation.

3.1.2 Loss of Mains detection in current codes (ER G59 and ER G83)

A limitation of RoCoF and voltage vector shift methods evaluating a singular observation are their potential ambiguity. Switching operations resulting in a change of impedances as well as faults in electrically close feeders frequently result in a phase shift. Narrow tolerances may result in erroneous island detection and consequently frequent, unintended plant trips. As a consequence technical provisions have to find a compromise between reliable plant and system operation (no nuisance tripping) on the one hand and safe LOM detection on the other hand.

The proposed changes24 in RoCoF response aim to overcome this sensitivity to singular events by introducing a requirement for a measurement period of 500 ms. Generator trip is only allowed if the RoCoF value is continuously above the trigger level during the complete measurement period. A problem of the current definition is that no withstand capability is defined. Depending on the applied averaging algorithm during the detection period, the given requirement assumes a virtually indefinite RoCoF withstand capability within the period (for illustration see Figure 10).

Figure 10: RoCoF event – illustrative example for current requirement versus withstand capability. The value of the RoCoF trace clearly exceeds the trip level. However, during the detection period the value is slightly below trip level

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24 Already applicable to generators of 5 MW and above, see ER G59/3.
for a short time and, hence, the generator is not allowed to trip. As no upper limit for the RoCoF value is specified, the expected withstand capability is virtually indefinite.

Similarly, in case of transient oscillations with RoCoF values changing polarity, the detection period is repetitively restarted during zero crossings preventing generator disconnection. This may depend on averaging algorithms within the protection relay and behaviour may vary between particular devices.

The technical provisions (ER G59 and ER G83) provide a certain flexibility in selecting the most appropriate protection scheme. ER G83-2 (2012) states under 5.3.2 Loss of Mains Protection: RoCoF and Vector Shift “are two common methods used to detect loss of mains in SSEGs [Small Scale Embedded Generators] though other techniques are also acceptable.” The industry consultations revealed that manufacturers make intensive use of this flexibility by choosing LOM detection mechanisms which are not specified in the technical standards. The standards do not require the manufacturer to specify the used mechanism. As a consequence, the generator’s response to events differing from the testing conditions is more or less unpredictable. This is particularly true for type tested equipment.
3.2 Survey of manufacturers

In order to evaluate how manufacturers apply the requirements for the different technologies, we performed a survey through in-depth telephone interviews with selected industry experts as well as a literature research. In addition, our analysis relies on experience gained through previous projects regarding LOM settings of distributed generation.

According to the analysis of the installed capacity of distributed generation below 5 MW in section 2.1 (Photovoltaic: 56%, Gas and Bio: 24%, Wind on-shore: 15%, Hydro and Wave: 5%), we focused our interviews on manufacturers for the most relevant technologies. As the questions relate to sensitive market information (e.g. sold capacity or implemented control algorithm), we confirmed to keep the individual information confidential and just present aggregated data. So far we contacted the following companies:

- **Photovoltaic**: We contacted the following manufacturers of PV inverters: SMA, Fronius, Power-One (ABB) and KACO. In general, the inverter market in the UK is dominated by a few companies. As shown in Figure 11 the estimated market share of these four companies in UK is about 90%. Therefore the findings from the interviews represent the majority of the installed capacity.
- **Gas and Bio**: The market for power units based on gas or biomass is strongly heterogenic and diverse. For the UK market a comprehensive overview on the relevant manufacturers and market shares does not exist. That’s why we selected the manufacturers based on our experience and the lists of members of associations like CHP Association, Energy UK or Association for Decentralised Energy. In total, we contacted the following manufacturers for engines and turbines: Jenbacher (GE/Clarke Energy), Woodward Power Solutions, MTU, MWM, MAN, Siemens, Bosch and 2G Energy. Usually the companies sell engines, turbines or complete gensets for both energy sources, gas and biomass25.
- **Wind on-shore**: The wind market is dominated by a number of companies. Figure 11 shows the estimated market share for all wind turbines (on-shore) in UK. The explicit26 market share of manufactures for wind projects below 5 MW is not publically available. For this study we contacted the following wind manufacturers: Siemens, Senvion27, Enercon and GE.
- **Hydro and wave**: Regarding the small amount of relevant capacity (less than 250 MW), we relied on the outcomes of interviews performed earlier. Entities approached were the Andritz Group and further German manufacturers like KWT Hydro, Burger Wasserkraftanlagen or F.EE.

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25 Based on individual DNO datasets the generating units using diesel fuel do have a share of about 1% of all distributed generation with less than 5 MW. In addition, diesel gensets are usually used as an emergency power system and therefore do not have high full load hours per year. Due to this two reasons we do not consider diesel gensets explicitly in the further analysis.
26 We estimated the market share of different manufactures based on the reported numbers of wind turbines in ‘Wind Energy in the UK – State of the Industry Report’ (2014).
27 Also representing knowledge previously related to Nordex.
**Protection equipment (RoCoF relays) and plant commissioning:** Finally we performed interviews with experts from manufacturers of control and protection equipment like Deep Sea Electronics, DEIF, Siemens, Woodward and Tele Haase.

Figure 11 estimated market share of PV inverters in 2012 (left) and of wind on-shore in 2013 (right) based on selected interviews with manufacturers, Solarbuzz: UK PV Market Entry Guide (2012) and Wind Energy in the UK – State of the Industry Report (2014)

### 3.3 Characteristics per technology

Technical codes in general leave room for flexibility in how to apply them. Manufacturers implement LOM methods based on their interpretation of the codes. In general, the implemented algorithms are not documented. Type certificates are provided based on standardised testing procedures. Real world conditions, however, may substantially differ from testing conditions. For the network operator this leads to uncertainty of the actually applied specifications and how they translate into plant behaviour.

Certain technologies and particular technology applications inevitably are associated with some limitations and, hence, may require specific ‘derogations’. We describe technical characteristics and how certain specifications are applied in practice according to manufacturers’ explanation. In addition, we summarize the technical life and maintenance intervals per technology. These factors may affect the implementation of potential retrofit options.

The descriptive summary is based on interviews with manufacturers active in the GB market, as listed in section 3.2. The positions summarised reflect the view of the manufacturers during the interviews. They do not necessarily represent an industry consensus or our own assessment.
3.3.1 Wind onshore

Regarding frequency protection settings, wind turbines need to be classified in two basic technologies:

- **Fixed speed wind turbines ('Danish design'):** In this case, an asynchronous generator is directly coupled to the grid and, hence, the grid frequency directly determines rotor speed. The capability to control the power output is often limited due to using passive stall control. Any deviation of the frequency will directly influence the speed of the rotor. However, due to the systematic slip of the asynchronous generator, the rotor’s angle velocity and network frequency never are exactly the same. Operation of the generator itself is possible, even with frequency fluctuations. If the rotor cannot follow fast external frequency changes due to its inertia this will just result in active power variations, overcurrents and increased reactive power consumption. As a consequence of extreme excursions, secondary protection mechanisms may disconnect the unit.

This design was widely used in the early years of wind technology but has been completely replaced by more advanced concepts more than a decade ago. We estimate that not more than about 100 MW of small wind farms (< 5 MWel) are still in operation in GB. From that point of view, this category is of limited importance.

- **Variable speed wind turbines:** Rotor speed of the turbine and the frequency of the power system are decoupled by power electronics. In general, these units are equipped either with a synchronous generator and a fully rated converter or with a doubly-fed induction generator (DFIG). The power output is highly variable. Regarding the development of wind turbines and wind farms with less than 5 MW in Figure 2, the majority of these power units are variable speed wind turbines.

**Technical life and maintenance intervals**

Wind turbines have generally a design life of 20 to 25 years. Maintenance has to be provided by the manufacturer at least on an annual basis. At irregular intervals certain retrofits or updates are done to eliminate weak spots or optimise the operation of the turbine. Although extensive retrofits (e.g. exchange of electronic components) are not part of the regular maintenance, they could be combined with them.

Some manufacturers disappeared from the market or merged with other companies. Although service providers are familiar with the maintenance or minor retrofits, it is generally difficult to find employees who are familiar with the interpretation of older types, and can provide information on the impact of new specifications (e.g. LOM detection settings) to the system concept.

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28 Exceptions are e.g. V47 from Vestas and SWT1.3 from Siemens.
Loss of main detection and frequency protection settings

Technology specific RoCoF withstand capability:

- In general, regarding to the interviews with the manufacturers old direct coupled wind turbines are capable of withstanding a deviation up to 1 Hz/s without disconnection. Certain types may have difficulties.
- The interviewed experts\(^29\) confirm that modern wind turbines (fully rated converter as well as DFIG) should be capable to withstand 2 to 4 Hz/s for less than 0.5 s and at least 1 Hz/s for more than 1 s without disconnection. Exact values depend on the design of hardware and control.
- In modern turbines the RoCoF withstand capability is determined by the inverter controls.
- In future, specifications withstanding deviations of up to 4 Hz/s for 0.5 s to 1 s seem to be generally feasible.

Applied LOM detection mechanism

- Dedicated RoCoF monitoring is rarely implemented in the wind turbine controller. In general, LOM detection of wind turbines relies on tolerated windows for voltage and frequency. Additionally, often vector shift protection is applied. Active LOM mechanisms are not applied.

Expected behaviour related to currently implemented RoCoF settings:

- Manufacturers are not able to clearly predict the response of currently implemented LOM detection mechanisms to more intense RoCoF events. They consider the possibility of vector shift relays responding with an increased rate of (false) tripping.
- If Fault-Ride-Through functionality is activated in the control of the wind turbine, intense disturbances resulting in a deviation from the expected voltage profile will primarily trigger this mechanism. This might interfere with RoCoF detection. RoCoF detection only starts after running through FRT algorithms and, hence, overall response times may be longer than 0.5 seconds (depending on voltage profile).

Further remarks:

- In future, there is a potential interference with provision of synthetic inertia. Synthetic inertia releases immediate momentum to the system in order to limit frequency gradients. Such a capability might compromise the effectiveness of LOM detection based on RoCoF-like mechanisms.
- Countries like Denmark have been requiring settings like 2 Hz/s already for a couple of years\(^30\) (see also section 4.1).

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\(^29\) This statement complies with the results of the analysis of the DS3 working group in Ireland. Commission for Energy Regulation (CER): Rate of Change of Frequency (RoCoF) Modification to the Grid Code (2014)

\(^30\) Energinet.dk (2010): Technical Regulation 3.2.5 – for wind power plants with a power output greater than 11 kW; Technical Regulation 3.2.1 – for electricity generation facilities with a rated current of 16 A per phase or lower
Re-connection and synchronisation operation
As a consequence of a network-related shutdown of a wind turbine, circuit breakers or contactors within the wind turbine are activated and the generator is physically disconnected from mains. After detecting restoration of normal network conditions, wind turbines automatically execute the restart procedure and return to operation. Depending on the type of wind turbine and site specific settings the start-up time varies between a few and ten minutes. Only internal faults require a manual reset. In many cases even this can be done via remote access.

3.3.2 Photovoltaics

In this analysis the focus is on the inverter of the PV power plant being grouped into two basic types:

- **String inverter based:** The inverter itself is a highly integrated product including the relevant protection equipment. In general, the string inverter is a mass product and usually designed for an output of up to 20 kW[31]. Bigger PV plants often consist of several connected string inverters. Usually manufacturers produce the same hardware for all countries in Europe and just adjust the software for country specific requirements. As seen in Figure 8 the PV market in the GB is strongly dominated by small string inverter based units.

- **Central inverter station:** For this type the energy conversion of the whole PV plant is done by a number of central stations each of which converts power from many strings of PV modules. Although these stations are manufactured in series, the design and internal components are usually adjusted for the individual PV plant, starting with a power output of about 100 kW. In contrast to power units based on string inverters, the protection devices are equipped as an external component in the plant based on central inverter station.

Technical Life and maintenance intervals
Inverters have an average design life of up to 15 years. Because the energy conversion unit does not include mechanical components, in practice maintenance of inverters is very limited. Large PV plants, however, do have regular maintenance. Depending on the manufacturer, this may include the inverters, e.g. cooling systems, software updates for the firmware and control programmes.

Loss of main detection and frequency protection settings

*Technology specific RoCoF withstand capability:*

- In general, inverter controls do not actively monitor RoCoF values. Depending on manufacturer and type, the control algorithms just ignore RoCoF levels of 2 up to 4 Hz/s.

*Applied LOM detection mechanism*

- Most of the manufacturers use a mixture of passive and active LOM methods to detect islands. Dedicated RoCoF algorithms are implemented only in some cases. Even then they are rarely activated.

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[31] In this analysis domestic PV up to 4kW, which represents around 50% of the installed capacity in the UK is included.
• The fixed thresholds for over- and under-frequency are implemented in line with the applicable network codes (ER G83, ER G59). Hence, one can assume that they are implemented equally for all manufacturers and products.

• The specific LOM algorithm differs from manufacturer to manufacturer. There is no standard or common algorithm and even implementation of similar algorithms may differ substantially between manufacturers. According to the interviews, frequency shift\(^2\) is most common for both types of products sold in the UK market.

• At medium voltage level, active LOM is never activated.

Expected behaviour related to currently implemented RoCoF settings:

• The interviewed manufacturers expect that more intense RoCoF values in the power system do not interfere with the implemented LOM methods. Most likely PV converters will not disconnect during RoCoF events up to 1 Hz per second. The implemented LOM detection mechanisms do not monitor the duration of such an event. Hence, after some time and due to the increasing frequency deviation only a violation of the absolute frequency tolerances will result in the converter ceasing energisation.

Further remarks:

• The manufacturers see an emerging conflict between fault ride through (do not disconnect) and LOM (do disconnect).

• The algorithm used to detect and operate RoCoF differs by each manufacturer and therefore its performance will differ. (How exactly to measure the frequency and the df/dt).

Re-connection and synchronisation operation

The electronics of the inverter unit have a fast response time in operation and re-connection. Depending on the type of inverter and its control strategy, the start-up time varies between several seconds and a few minutes. In general, the duration to start-up and re-connect is less than one minute. Although the implemented algorithm could be faster, the length of this process is required to ensure a re-connection after the network has been stabilised. The start-up of a PV power unit is automatic unless a fault requires a manual reset, which can normally be made via remote access.

3.3.3 Gas engines and biomass

The general design of power units with natural gas or biomass as energy source can be classified in two types:

• Piston engines: The combination of a piston engine and generator is widely used for power units with less than 1 MW. Higher ratings are exceptional. The determining components in the frequency response and considered in the survey are motor, generator (synchronous or asynchronous machines), as well as the control and protection equipment. In the power

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\(^2\) However, the actual algorithm of the frequency shift techniques applied and how these interact with other ER G83 and G59 requirements could not be explored in depth and may warrant further consideration and research.
range of a few hundred kilowatts, product series are widely used and equipment specifications are comparable. In the higher power classes, equipment specifications are customised individually depending on the use case. Especially in higher power ranges, often a number of units are used at a single location and multiple protection and control systems exist.

- **Turbo-generators:** Turbo-gensets consist of a combustion turbine or steam turbine in combination with a generator. In most case the turbine is coupled directly to a synchronous generator on a single shaft. Gearboxes are rarely used. Sometimes a clutch connects the shafts of turbine and generator. This technology is commonly applied in large power plants. In the capacity range being considered in this study (0 to 5 MW), the technology is more exceptional. Recently, micro-turbines made some progress but their market share still is very limited. These units operate at high rotational speed and, hence, are connected to the network via power electronic interfaces. Basic components which may be influenced by frequency deviations are: turbine, generator, power electronic converters, frequency control and protection systems. Although the control and protection hardware consist of certain standard components, the unit itself varies as they are tailored to the specific use case (especially the programming of the controller).

**Technical life and maintenance intervals**

Mechanical wearing of parts and components subject to high mechanical stress require regular maintenance. A turbine is typically serviced annually and is designed to operate for 20 to 40 years. Combustion engines have intensive use of mechanical parts which wear faster, resulting in a relatively shorter life cycle of 10 to 15 years. After this period, the plant economics is assessed to decide whether the system should be shut down or retrofitted. Although extensive retrofits (e.g. exchange of electronic components) are not part of the regular maintenance, they could be combined with them.

A retrofit and replacement of essential components of the engine or turbine and the control equipment and related protection equipment is usually made in combination with a major revision or overhaul, after some 10,000 operating hours.

**Loss of main and frequency protection settings**

*Technology specific RoCoF withstand capability:*

- In general, the RoCoF capability is limited for synchronous generators being directly coupled to the grid. The risk of pole slipping within the synchronous generator is mentioned as the limiting factor.
- According to the manufacturers and current studies^33^ ranges in excess of 1 Hz/s often seem to be feasible, even for existing plants.
- Some manufacturers expressed concerns regarding extended RoCoF periods to withstand. They claim that the 500 ms RoCoF withstand duration may be more challenging for the plant.

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^33^ DNV KEMA (2013): RoCoF – An independent analysis on the ability of Generators to ride through Rate of Change of Frequency values up to 2Hz/s
than the gradient itself. In the interviews, manufacturers were not able to clearly explain mechanisms and resulting restrictions regarding the period. In their view dedicated investigations would be required.

- Regarding the prime mover (existing) piston engines are more tolerant than turbo-generators. This is due to the more sensitive stability of the combustion process in the turbine.
- Generation sets are often assembled by system integrators using standard industrial components. Even in case the specifications of the components allow for more intense RoCoF events, integrity of the genset as a whole may need a dedicated assessment.

**Applied LOM detection mechanism**

- Internationally, usage of vector shift is dominating, but in the UK also RoCoF is applied regularly. Manufacturers are unable to reliably estimate respective portions.
- Dedicated RoCoF relays are common, however embedded protection integrated in the genuine plant controller is common as well. Selection of LOM detection and adjustment of settings is simple in the case of dedicated protection relays. Embedded control may be more difficult to reconfigure.

**Expected behaviour related to currently implemented RoCoF settings:**

- Manufacturers are reluctant in predicting plant response to more intense RoCoF events (assuming an adjustment of RoCoF protection). They tend to make reservations with respect to the response of secondary protection mechanisms, in particular with respect to longer withstand periods (e.g. 500 ms). Respective experience is lacking.

**Further remarks**

- In other countries RoCoF withstand requirements of 1 Hz/s and more have been applicable already for years.\(^{34}\)
- In industrial CHP applications the impact of intense RoCoF events on related thermal processes may require additional attention.

**Re-connection and synchronisation operation**

Usually, gas and biomass based power plants do not automatically re-connect after disconnection caused by voltage or frequency deviation. The start-up and re-connection of the power unit needs to be manually confirmed and takes at least some minutes. This is due to the fact that operation of biogas or CHP plants in general is operator based. In contrast small units manufactured for mass markets (e.g. micro CHP in residential environments) may re-connect automatically after some minutes.

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\(^{34}\) The Danish Grid Codes require a withstand capability of +/-2.5 Hz/s over 80-100ms without disconnecting. Energinet.dk (2008): Technical Regulation 3.2.4 – Thermal Power Station Units larger than 11 kW and smaller than 1.5 MW; Energinet.dk (2008): Technical Regulation 3.2.3 – Thermal Power Station Units of 1.5 MW and higher
3.3.4 Hydro and Wave

Similar to wind turbines, hydro power plants can be categorised in fixed speed and variable speed hydro turbines. Most small plants are directly coupled to the grid regardless of whether they have a synchronous or asynchronous generator. Systems being built during the last decade (including wave) often use variable speed drives with power electronic converters.

The type of generator used as energy conversion systems in small hydro power plants are:

- (Asynchronous) induction generator, usually in systems up to 0.3 MW
- Synchronous generators in plants with a capacity exceeding 0.3 MW, as well as in very old plants for stand-alone operation.
- Synchronous generators with converters, in modern new facilities.

Directly coupled, synchronous generators are most sensitive to RoCoF events. Potential issues raised during the interviews are high torques, saturation of the iron core and resulting overcurrent as well as potential loss of synchronism. In their early years, very old plants have been operated regularly in small electrical systems (de facto islands) and it is quite likely that they have been subject to more frequent and more severe RoCoF events than under current conditions. Unfortunately, respective experiences have not been systematically recorded. Due to the limited and partly old plant population, the diversity of manufacturers or system integrators and the dominating impact of secondary protection equipment, care is required when drawing conclusions on plant behaviour. Generalising statements have to be avoided.

3.3.5 Dedicated RoCoF relays

Most distributed generation facilities are equipped with dedicated protection / RoCoF relays at their interconnection. Only in case of small scale, residential PV systems for cost reasons separate protection devices are omitted.

Applied LOM detection mechanism

- In LV connections vector shift is applied in most cases (more than 90% of the cases). This is because of frequent nuisance tripping of RoCoF in LV networks. In case of higher voltage connections, application of RoCoF is more common but robust figures are difficult to provide.

Expected behaviour related to currently implemented RoCoF settings:

- A time delay in combination with RoCoF detection was introduced recently by the transition from ER G59 Issue 3 (2013) to ER GE59 Issue 3 Amendment 1(2014). The delay was not part of device specifications before 2014. Some models of RoCoF relays may not have the

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35 According to ER G59 Issue 3 (2014) the delay applies to Small Power Stations ≥ 5 MW. These plants are out of the scope of this study. ER G83 Issue 2 (2012) generally allows immediate tripping. Hence, in the context of this analysis concerns expressed by manufacturers related to the duration of a RoCoF event may be ignored.
capability to introduce this new parameter. In such cases updating protection settings to the current requirements may imply an exchange of hardware.

Further remarks

- Manufacturers / operators of combustion engines in general perceive RoCoF relays as being related to plant protection rather than network protection.
- If new regulations require existing plants to extend the RoCoF range it is likely that some of the operators will change over to vector shift.
- Protection settings are coordinated and checked during commissioning. Repetitive compliance tests during the plants technical lifetime are not common industry practice. There are no obligatory or standardised processes for safeguarding integrity of protection settings between different levels (e.g. internal controller of generator versus obligatory external dedicated RoCoF relay at connection point). Without those processes there is a risk that even after adjustment of RoCoF relay settings in one device generators could trip unexpectedly due to inappropriate protection settings in the other one.
- State-of-the-art protection devices come with some capability of event recording. Potentially, this allows systematically evaluating these records and collecting respective information. This offers an extremely effective opportunity to better understand the behaviour of DG in relation to disturbances, under real world conditions and over extended operational periods.
3.4 Summary technology review

- Dedicated RoCoF algorithms apparently are rarely implemented in the primary plant control of inverter based DG.
- In PV active LOM mechanisms are widely used (frequency shift). The other technologies rely on passive methods. Vector shift is dominant, certainly for gensets (CHP, biomass). The latter technologies also use dedicated RoCoF algorithms in the UK.
- Inverter based technologies, being PV and wind, generally can deal easily with enhanced frequency gradients. There is no evident risk for hardware damages in the generation facility.
- Manufacturers expect that inverter based technologies behave quite robust as long as the absolute voltage and frequency limits are not hit. They expect that units stay connected and do not cease generation in a wider RoCoF range than previously required by the original standards.
- Reliably predicting the specific behaviour and tripping levels of the applied protection mechanisms during such an event, however, is difficult. Secondary, plant protection mechanisms (overcurrent, torque) may also influence the behaviour in case of frequency excursions.
- Manufacturers of combustion engines claimed that the duration of a frequency excursion or a RoCoF event may be more challenging for the plant behaviour than the gradient itself. They are concerned regarding the consequences of changed requirements.
- According to protection specialists most generation facilities are equipped with dedicated RoCoF relays at their connection point. This holds for all generation technologies. Only in case of small (residential) PV systems, for cost reasons, separate protection devices are omitted. Given the structure of the plant population probably nearly 1,500 MW of PV do not have supervisory RoCoF protection. (50% of the total capacity is represented by PV systems up to 10 kW.)
- In case of low voltage connections vector shift detection is dominating. RoCoF is applied infrequently. As a consequence, probably more than 2,000 MW out of the total DG capacity of 4600 MW do not use RoCoF detection at all.
- Based on this reasoning we assume that RoCoF application apparently is restricted to CHP/biogas and hydro plants with HV connections. The affected capacity is about 1,100 MW. An additional 1,300 MW of wind and PV with HV connections might use RoCoF relays at their connection point (see Figure 12). If desired, most of this capacity can be reconfigured to other LOM detection mechanisms, e.g. vector shift, with limited effort.
In general, manufacturers do not have information about external protection devices and their site specific settings as implemented in DG projects.

Protection settings are coordinated and compliance tested during commissioning. There is no standard process safeguarding integrity of protection settings during the plant’s life. Regular, repetitive checks are uncommon. In case protection schemes are subject to changes after commissioning (e.g. as a consequence of some retrofit programme) coordinated adjustment will be a challenge.
3.5 Cost indicators for retrofit activities

The limited quality of the existing data and the differences between individual generation facilities do not allow an accurate assessment of costs related to potential retrofit actions. The following considerations provide a comparison of options. We use numbers where they help to distinguish such general options. Nevertheless, it would be inappropriate to discuss the cost indicators and estimates isolated from these limitations.

The monetary values included in the following discussion relates to hardware changes and related labour costs. They do not reflect administrative costs for managing a retrofit process as for example communication, coordination, travel, quality management, etc. Experience in similar cases showed that this kind of overhead costs can be significant and in the same order of magnitude as the hardware related activities\textsuperscript{36}. Additionally, structure and volume of overhead costs is highly influenced by the manner how the process is organised. For instance, travel costs may be significantly reduced by coordinating retrofit activities with regular maintenance.

As the characteristics of plant behaviour, retrofit costs are technology specific. The following table illustrates the possibilities and provides indicative values.

<table>
<thead>
<tr>
<th>Plant compliant also with new requirements</th>
<th>Retrofit / adjustments required</th>
</tr>
</thead>
<tbody>
<tr>
<td>no change necessary</td>
<td>Retrofit of controller / hardware / software</td>
</tr>
<tr>
<td>-</td>
<td>Retrofit impossible</td>
</tr>
<tr>
<td>Cost low</td>
<td>Higher cost</td>
</tr>
<tr>
<td>(£500...£1,000/unit)</td>
<td>(£1,000...£20,000/unit)</td>
</tr>
<tr>
<td>-</td>
<td>High cost</td>
</tr>
<tr>
<td></td>
<td>(£500...£1,000 /kW)</td>
</tr>
<tr>
<td>RoCoF relays</td>
<td>Control and protection equipment</td>
</tr>
<tr>
<td></td>
<td>exchange of major plant components: PV inverters</td>
</tr>
</tbody>
</table>

With the existing information and even after the industry inquiries it is highly uncertain which part of the plant population will comply with changed RoCoF settings without modification (first column in Table 2) and which part potentially is subject to be corrective measures. As summarised in the previous paragraphs, at least for PV and wind power plants, probably a significant share of the existing plants is able to comply with future requirements without change. The investigations performed by the University of Strathclyde will help to further qualify the remaining challenge.

\textsuperscript{36} ECOFYS, Deutsche WindGuard, Becker Büttner Held, IFK Stuttgart (2014): Development of a retrofit program for distributed generation in Germany for the prevention of frequency stability problems in abnormal system conditions.

\textsuperscript{37} This cost assumption aligns to the estimation of the working group in phase 1 according to Energy Networks Association (2013): Frequency Changes during Large Disturbances and their Impact on the Total System.
However, the measurements are limited in scope (focus on PV) and in the number of samples and, hence, may not be sufficiently representative for the plant population as a whole. Testing the complete plant portfolio instead, unfortunately is no viable option as this would cause excessive cost.

An alternative approach for assessing RoCoF related DG behaviour might be considered here. A representative sample of the plant population could be equipped with fault recorders. In that way the response of generators to rare RoCoF events could be continuously monitored. The particular advantage of this method is that also wind energy converters and CHP or biomass plants can be assessed under realistic conditions. Because of their rated capacity in the MW range, these technologies are not suitable for being cost effectively tested in a lab environment. Of course, also this approach causes costs and does not guarantee that relevant results are produced in a certain period of time. It has to be considered as a potential additional option, allowing to fine tune corrective measures in the longer run.

In order to illustrate the technology specific differences in costs of potential corrective measures we assume the total capacity needs to be retrofitted (see Table 3). This is an unrealistic, worst case assumption but it allows to rank potential efforts in terms of cost-effectiveness. Retrofitting PV is by far the most expensive option, both, in terms of absolute figures and on a per kW basis. According to the manufactures this is due to the fact that implementing a completely new, compliant RoCoF algorithm in an inverter is prohibitive and requires an exchange of the existing device.

### Table 3: Cumulative costs of retrofit activities per technology, covering the complete DG population

<table>
<thead>
<tr>
<th>Technology</th>
<th>Units</th>
<th>Capacity in MW</th>
<th>Magnitude of costs in £</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV</td>
<td>500,000</td>
<td>2,600</td>
<td>&gt;1 billion</td>
</tr>
<tr>
<td>Wind</td>
<td>1,100</td>
<td>700</td>
<td>1 ... 10 million</td>
</tr>
<tr>
<td>CHP controllers</td>
<td>1,400</td>
<td>1,100</td>
<td>1 ... 10 million</td>
</tr>
<tr>
<td>Hydro and wave</td>
<td>1,000</td>
<td>250</td>
<td>1 ... 10 million</td>
</tr>
</tbody>
</table>

In cases where corrective measures are limited to an adjustment of settings in existing RoCoF relays or controllers, costs may decrease with a factor of up to 10 compared to the figures provided in Table 3. Most likely, this applies to state-of-the-art wind energy converters with inherently high RoCoF withstand capability and dedicated RoCoF relays at the point of common coupling.
4 Task A.3: International Experience

4.1 European background and related developments

Protection settings at distribution level in interconnected systems at continental Europe have been subject to national regulation and even have been different per DSO within countries. The ENTSO-E codes currently under development or in the comitology process, respectively, are a major attempt to align these requirements and create a common basis for coordinated development across Europe. Most relevant in this context are the Network Code on Requirements for Grid Connection Applicable to all Generators (RfG) and the Demand Connection Code (DCC). Also in future the codes will leave room for national implementation. As a novelty, the RfG addresses the possibility to require retrospective changes on existing equipment if this is techno-economically justified.

LOM detection in the continental system does not rely on RoCoF algorithms but is mostly based on absolute ranges for voltage and frequency. Some additional mechanisms are applied, varying per country. A few national codes contained specifications regarding the capability to withstand RoCoF events or RoCoF like phenomena.

The Danish TSO Energinet DK required a RoCoF withstand capability of at least 2.5 Hz per second for thermal power plants already 2008[38]. Since then this requirement has been included in all generator related connection requirements covering all technologies and voltage levels down to low voltage connections. Application of vector shift relays has been prohibited with reference to frequent false tripping. Wind energy converters must not stop operating as a consequence to vector shifts up to 20°. In Germany application of vector shift relays also has been banned, starting at medium voltage level with the publication of the medium voltage directive in 2008. Recently, the guideline for high voltage connections extended this requirement to the 110 kV level. However, in Germany it is acknowledged that plant manufacturers and system integrators still regularly implement vector shift relays as a means of equipment protection. Network operators tolerate this practice.

4.2 Germany

In Germany RoCoF has never been applied as LOM detection mechanism. Anti-islanding concepts at distribution level relied on fixed thresholds for voltage and frequency. In low voltage distribution networks additionally active monitoring of (sudden changes of) the network impedance has been used as LOM detection.

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[38] Energinet DK: ‘Technical Regulation for Thermal Power Station Units of 1.5 MW and higher - Regulation for grid connection TF 3.2.3’ Version 5.1, Fredericia, October 2008
The evolution of network codes in Germany and the necessity of retrofit activities has been driven by the rapid growth of DG and in particular renewable capacities during the last two decades. In the year 2000, renewables-based generation (RES-E) capacity was nearly 2000 MW. Because of their limited scale, apparently all RES-E generation facilities were connected to low and medium voltage (LV, MV) networks and, thus, belonged to the domain of distribution system operators (DSO). Driven by the Renewable Energy Act (Erneuerbare Energien Gesetz) RES-E capacity at LV and MV levels grew rapidly. At the end of 2013 the amount of DG, i.e. RES-E plus CHP, was about 90 GW. This represents about 50% of the total installed generation capacity in Germany and exceeds system peak load.

Technical codes and standards were actively developed but could not keep pace with the structural changes of the generation plant. Reasons for this discrepancy are manifold. The growth rate of DG was underestimated again and again, even by the branch organisations. Additionally there was a limited understanding of the implications of these changes in science and industry. Finally, creating consensus on adequate technical regulation, respective industry consultations, drafting and finalising of technical documents inevitably took time.

As a consequence, there were several cases where capacities in the GW range already existed when new standards were released. Related to four particular subjects the responsible ministry decided to implement corrective programmes affecting existing plants.

Table 4 below summarises and compares some of the key characteristics of the various programmes. The character of the programmes and the particular experiences and challenges during implementation are described more in detail in section 6.5 in the appendix.
Table 4: similarities and differences between German retrofit programmes

<table>
<thead>
<tr>
<th>Character</th>
<th>Ancillary Services Ordinance SDL WindV</th>
<th>Remote interfaces for generation management</th>
<th>System Stability Ordinance I</th>
<th>System Stability Ordinance II</th>
</tr>
</thead>
<tbody>
<tr>
<td>Responsible</td>
<td>Plant owner</td>
<td>Plant owner</td>
<td>DSO</td>
<td>TSO</td>
</tr>
<tr>
<td>Stimulus</td>
<td>Bonus payment on FIT</td>
<td>Penalty (FIT suspended)</td>
<td>Penalty (FIT suspended)</td>
<td>Penalty (FIT suspended, fines)</td>
</tr>
<tr>
<td>Cost allocation</td>
<td>Socialised (Renewables levy, all electricity users)</td>
<td>With individual plant owner, reasonable amount, lump sum</td>
<td>Socialised (network charges, users connected to the particular DSO)</td>
<td>With individual plant owner, cost cap (7.50 €/kW)</td>
</tr>
<tr>
<td>Coverage</td>
<td>Ca. 12 GW, i.e. 60%...70% of technical potential</td>
<td>Apparently complete population (6...12 GW)</td>
<td>Large share of population (&gt;80%)</td>
<td>Apparently complete population (derogations?)</td>
</tr>
<tr>
<td>Quality control</td>
<td>Type and project certificates</td>
<td>Only individual samples</td>
<td>Only individual samples</td>
<td>Part of programme</td>
</tr>
</tbody>
</table>

4.3 Netherlands

Also in the Netherlands RoCoF LOM protection has never been applied. LOM detection is based on absolute tolerances for voltage and frequency. Operational ranges are specified in the system code. The code covers both, connections to the High and Extra High Voltage Networks and to distribution networks below 110 kV. TSO and DSO related requirements have been integrated in one single document already for two decades. This distinguishes the Dutch framework from many other countries.

The required operational ranges for Transmission and Distribution related connections, respectively, have been similar.

It has to be emphasised that the frequency ranges specified for both codes are limited to 48.0 Hz (underfrequency) and 51.0 Hz (overfrequency). In that sense, they do not completely comply with future ENTSO E ranges (47.5 ... 51.5 Hz). According to the national TSO TenneT, the system code will be aligned with the RfG once the respective requirements are legally binding across Europe. However, corrective measures affecting existing plants are quite unlikely. Given the stringent requirements on the cost benefit analysis supporting any retrospective change and the heavy stakeholder process TenneT does not expect such an initiative being successful.

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39 Systeemcode Elektriciteit, Voorwaarden als bedoeld in artikel 31, lid 1, sub c van de Elektriciteitswet 1998, Autoriteit Consument en Markt, January 2015
40 Frank Spaan, TenneT TSO, Verbal communication, March 2015
Of course, already now network operators and connection applicants are free to agree on extended frequency ranges via bilateral contracts. TenneT has no information whether this option is used in DSO connection agreements.

Figure 13: Operational voltage and frequency ranges as required for generators connected to networks below 110 kW in the Netherlands (source: System Code []

During the last decade, in the Netherlands DG has been an important part of the generation portfolio. Maximum national system demand is slightly higher than 20 GW. The cumulated CHP capacity in distribution networks amounts several GW, of which about 3 GW in the greenhouse sector only. Most of the total CHP capacity concerns units larger than 5 MWel. Wind power amounts for nearly 3 GW and the total PV capacity is in the range of 1 GW. A limited fraction of the PV capacity concerns very small ‘plug and play’ PV systems simply being connected to wall sockets by final customers. The Dutch distribution network operators agreed to tolerate these systems in residential connections up to a capacity of 600 W per separate circuit.

As in the UK, no register for DG installations exists in The Netherlands neither an obligation for plant operators to supply data, except those required for the connection agreement with the respective DSO. Potential in depth assessments of the plant population will face challenges in terms of data coverage and quality.

The operational range illustrated in Figure 13 applies also to low voltage connections and, hence, to small scale generation, down to kW range. Potential future changes will affect all technologies.
4.4 Ireland

In Ireland RoCoF has been used as LOM detection mechanism for decades. The current RoCoF capability required of all units in Ireland is 0.5 Hz/s\(^41\). However, the TSO’s in Ireland and Northern Ireland, EirGrid and SONI, concluded that this setting would need to be revised to deliver Government targets of 40% of renewable energy by 2020. Current RoCoF response is one of the factors restricting the ability of the TSO to operate with System Simultaneous Non-Synchronous Penetration (SNSP) above 50%. In 2014, more than 1000 hours were registered at a SNSP above 45% and in the first two weeks of 2015 around 35% of the wind power infeed had to be curtailed as the limit was hit quite often.

In order to facilitate the delivery of the 2020 renewable target, EirGrid and SONI have proposed a modification of the RoCoF setting to 1 Hz/s measured over 500 ms to all generators connected to the transmission grid which would be a key factor in facilitating a SNSP penetration of 75%. The system operators referred to a desktop study which shows that, theoretically, generators can comply with a RoCoF of 1 Hz/s rolled out over 500 ms. However, the study indicated that in some instances generators may experience instability when operating at full leading power. To clarify the issues and risks detailed technical studies regarding the capabilities of individual generators to withstand the new setting have been commenced (work stream 1). Higher priority units are required to complete their studies by May 2016\(^42\) and declare their compliance or submit a derogation. Low-priority units must do so by October 2017. The modifications proposed by EirGrid will not formally become binding before the studies’ results have been approved. In case that studies are delayed or show negative results, EirGrid has been instructed by CER to investigate complementary technologies to increase the inertia of the system, this investigation considers technologies such as Synthetic Inertia from wind turbines or storage technologies (work stream 2). New generators connecting to the system will undergo RoCoF compliance testing, however, they will only be subject to complying with the new standard after the CER approves the modification, that is not before May 2016 and dependant on the result of the generator studies.

On the other hand, the DSO has agreed to modify the Distribution Code to reflect the new RoCoF standard and found that it is unlikely that demand customers should be negatively impacted by it. Currently an inventory of the existing DG population is undertaken. This exercise is similar to the investigations described here in section 2. A Distribution Code modification was recommended by the Distribution Code Review Panel and is expected to be approved by the CER after completion of the RoCoF Generator Studies Project and the assessment of the results by EirGrid. The DSO will be responsible to monitor the impact of the new RoCoF standard on demand customers and the quality of supply.

\(^41\) The current Irish Grid Code (CC.7.3.1) does not specify a time delay for RoCoF.
\(^42\) Great Island 4 (460MW CCGT, commissioned 2014) recently became the first power station to date to confirm compliance with the proposed 1 Hz/s withstand requirement.
4.5 United States

RoCoF is not required or applied by network operators in the United States as a LOM detection mechanism. LOM detection mostly relies on fixed tolerances for frequency and voltage and to a lesser extent on intertripping and reverse power protection. RoCoF however is not generally prohibited. Operators of conventional power plants use it for protection of their equipment (synchronous generators), at least in some parts of the country\textsuperscript{43}. As a consequence, RoCoF events may trip generation also in parts of the US.

One specific challenge in the US is that many interconnection standards with different requirements coexist. The dominating standard applicable to distributed generation is IEEE 1547 ‘Interconnecting Distributed Resources with Electric Power Systems’. However, utilities and regional regulative authorities implemented their own standards. These standards differ in methodology as well as what concerns parameters for protection settings. In general the tolerated ranges are tight and DG is expected to cease energisation immediately in case of minor disturbances on the network.

In line with earlier assessments, in 2013 a dedicated report of the North American Electric Reliability Corporation (NERC)\textsuperscript{44} highlighted the risks for system security resulting from the current industry practice in combination with the growth of DG in parts of the US.

In 2014 the amendment of IEEE 1547a removed the general constraint on ride through capabilities for DG\textsuperscript{45}. Still, any ride through capability of a DG plant may be only activated under mutual agreement between the DSO and plant operators involved. There is no general requirement or even allowance for such capability.

The regional interconnection rules require the same traditional settings for LOM detection. Industry experts assume that it is very unlikely to achieve a national standard which regulates mandatory ride through capabilities in the foreseeable future. The views among the stakeholders simply are too different.

This is illustrated by the fact that in some regions connection requirements exist which define a high level of ride through capabilities and simultaneously advanced LOM detection concepts\textsuperscript{46}. The latter standard applies to electronic power converters, whereas most interconnection standards, including IEEE 1547 do not distinguish technologies.

As a compromise EPRI is currently undertaking efforts to recommend a uniform concept for defining ride through requirements for DG in order to reduce ambiguities\textsuperscript{47}. The particular settings still have to be defined by individual DNO’s.


\textsuperscript{44} NERC: ‘Performance of Distributed Energy Resources During and After System Sisturbance: Voltage and Frequency Ride-Through Requirements’, 2013

\textsuperscript{45} At transmission level Fault Ride Through requirements have been implemented and applied already for a decade.

\textsuperscript{46} For example the most recent version of Electric Rule 21 issued by the California Public Utilities Commission

\textsuperscript{47} Jens Bömer Electric Power Research Institute (EPRI) personal communication, March 2015
Throughout the last decade many of the grid connection requirements have been subject to changes. It is common industry practice to apply new requirements also to existing plants – as far as this is possible with reasonable effort. This is for example adjusting protection settings within specifications in the course of regular maintenance cycles). Major retrofit activities, however, have not been reported yet. Even the substantial changes introduced by Electric Rule 21, apply to new connections only. Apparently, risks caused by outdated settings have been considered being manageable⁴⁸.

5 Conclusions and recommendations

5.1 Conclusions

Data collection, management and access
- The combination of various existing databases provides a realistic and robust picture of the composition of distributed generation below 5 MW in the GB power system. Based on these data the total number of sites and respective capacities per generation technology can be estimated with reasonable accuracy.
- The level of detail of the existing data is limited and varies per data source. Datasets covering Great Britain completely, do not provide detailed and consistent geographical or technical information. Subsets, e.g. some DNO records, contain more information for their particular region or service area. However, these records vary in structure, underlying definitions and granularity. As a consequence, it is not straightforward to generate consistent additional information by linking those existing datasets.
- Starting from June 2015 DNOs will provide data on newly installed distributed generation above 1 MW in a consistent format to NGET as part of their Week 24 submissions. NGET will manage the database. However, this is restricted to plants above 1 MW, so a substantial part of the DG population still will not be covered. Taking the existing DG mix as reference, more than 50% of the total DG capacity (nearly 2500 MW) and in particular nearly 75% of the PV capacity would remain invisible also in future.

Capability to withstand RoCoF events
- The capability to withstand RoCoF events without compromising plant integrity or safety risks differs per technology.
- According to manufacturers’ views, technologies based on electronic power converters (PV, wind) in general might be capable to withstand significant RoCoF events (1 to 2Hz/s) without major changes.
- According to manufacturers’ views gensets often are capable of withstanding more intense RoCoF events (up to 1Hz/s). Individual assessments might be required to specify a suitable value per plant.
- However, manufacturers of combustion engines express concerns regarding RoCoF withstand capability over the proposed detection period of 500 ms.

Applied protection settings / technical requirements
- The existing technical requirements specify the expected behaviour of generators and, in that context, refer to certain LOM detection methods (RoCoF, vector shift, etc.). However, they do not restrict manufacturers in choosing different, suitable LOM detection methods.
- Because of this choice, applied LOM detection methods vary per technology.
- In PV and wind energy converters a variety of LOM detection methods is applied. Dedicated RoCoF algorithms, however, are not used and in most cases not even implemented.
• In gensets protection relays are used allowing a choice between RoCoF and vector shift detection. According to the manufacturers’ knowledge and protection experts, both options are regularly used by the end users.

• Most generation sites (excluding residential PV systems) use additional protection relays at their connection point. In LV connection the majority of these additional relays are configured for vector shift detection rather than RoCoF detection.

• As a consequence, 2,500 MW of DG with HV connection might use RoCoF. However, only about 1,100 MW out of this capacity, representing CHP/biogas and hydro, possibly use RoCoF in the genuine plant protection.

• Manufacturers of PV and wind energy converters assume that the units will not disconnect as a consequence of RoCoF events up to 1Hz/s. However, the manufacturers are unable to exactly predict the behaviour of different mechanisms with respect to RoCoF events with a greater gradient. The modelling and testing exercises ongoing in work stream B should help to gain respective experience.

• Testing should include (emulated) out-of-phase reclosure of circuit breakers. Respective scenarios are not covered by current standards and, hence, plant and protection behaviour is not specified in this field. Manufacturers of PV and wind energy converters have no clear position regarding the risk of damaging equipment. They tend to accept significant angle differences but are unable to make clear statements on the tolerated values. Manufacturers of gensets are more sceptical what concerns the robustness of their equipment with respect to out of phase reclosure due to the affecting physical moments.

International experience – key findings
• Germany: From a societal perspective cost of retrofit actions are justified and not prohibitive. However, even simple adjustments (fixed trigger values for frequency protection) are, depending on technology and control, partly even infeasible. Retrofit actions take at least 3 years to complete. They represent a major challenge for all parties involved. In particular quality monitoring and management proved to be extremely difficult.

In parallel with the start of the next retrofit programme, potential new technical requirements for future plants are discussed in the industry, for examples FRT capabilities at low voltage level. Recently, research regarding a further elaboration of LOM detection has been started. It is too early to conclude, whether those potential changes imply corrective measures for the existing plant in future.

• Ireland: The industry consultations highlighted that the capability to adapt to new requirements differs per technology. More thorough analyses are required before defining mandatory requirements. As a consequence, there is an obvious risk that the politically intended process of transforming the power system is delayed. To avoid delays transitional regimes are taken into account. In turn, these imply the potential need for corrective measures later on.

• US: Though the protection concepts applied are about the same (V, f settings) there is no uniform standard regarding LOM detection across the country. This represents a challenge for manufacturers because they have to comply with differing specific requirements. From a strategic perspective this may also be an opportunity, because it stimulates the design of flexible interfaces for protection settings.
5.2 Recommendations

**Data collection, management and access**
- A single database covering DG in the GB power system and including more detailed site and plant characteristics is desirable. The completeness of the dataset maintained by National Grid may be significantly improved if the chosen 1 MW threshold for new plants is removed or further reduced.

**Technical requirements and capability of DG**
- The inventories and (ongoing) tests will provide only limited evidence on the behaviour of DG with respect to RoCoF events. Complementary ways to gain the required knowledge may be extremely valuable. One option is event recording by monitoring a sample of DG plants. Many protection devices already offer this capability. It may take long to gain relevant information using this approach. Nevertheless, respective measurements would provide highly realistic information.
- In future, a clear distinction between withstand capability and required disconnection settings might remove ambiguities from technical standards and engineering recommendations.
- The reliability of different applied LOM detection mechanisms in power systems with an increased penetration of DG deserves further investigation.
- Dedicated attention has to be drawn to reconnection behaviour. This needs to be specified also in the technical standards. Manufacturers have to reflect potential events in the design of the plant protection. DNOs might consider gradual implementation of blocking mechanisms for auto-reclosure if the disconnected network is not dead.

5.3 Potential need for retrofit activities and related cost

- The response of the currently applied LOM detection mechanisms to more intense RoCoF events is still uncertain. With the information provided by manufacturers it is reasonable to assume that no general adjustments of the protection settings are required in case of PV and wind turbines with power electronic converters. According to the manufacturers’ opinion these plants will not trip as a consequence of RoCoF events of 0.5 Hz/s or more.
- Currently, vector shift is the preferred protection option in LV connections. Hence, also these plants do not require general adjustments of the protection settings due to changed RoCoF requirements. (Vector shift detection responds more robust to frequency excursions. Whether this method is effective and appropriate will be subject to future assessments.)
- This leaves a population of about 1,100 MW (CHP/biogas and hydro with HV connections) potentially requiring further consideration on potential need for a retrofit. Most likely also a significant share of this population is able to withstand with more intense RoCoF events without changes in the plant configuration. However, individual assessments may be inevitable.

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- External RoCoF relays of wind and PV with HV connections (another 1,300 MW) also may need to be reconfigured to apply new RoCoF settings. This may be combined with regular maintenance in order to reduce costs.
- Readjustment of the genuine plant controller to apply new RoCoF settings, e.g. in case of wind turbines or CHP plants, would be a major technical change. Technical feasibility and cost vary per technology and even model. While some units can be adjusted by modification of protection and control devices or algorithms, others would need to exchange hardware or cannot be retrofitted within the given plant structure.
- In case of PV, the required change of firmware to apply new RoCoF settings often will mean substituting the complete inverter. Consequently, specific per kW costs for retrofitting PV would be much higher than those for the other technologies (one or two orders of magnitude).
- In case potential retrofit activities to apply new RoCoF settings affect genuine plant control, it seems to be justified to start with gensets, hydro, wind, and, possibly, wave power. Including PV and, in particular, small residential systems in such an exercise should be initiated only after further, representative investigations on RoCoF behaviour of the PV inverters and a thorough assessment of the related risk for system security.
- More changes of the protection settings regarding plant behaviour might be worth being considered already now, as the implementation of the Network Code on Requirements for Grid Connection Applicable to all Generators (RfG) from ENTSO-E may result in adjustment of technical requirements anyway (e.g. frequency response at distribution level, Fault-Ride-Through at lower voltage levels, interfaces for curtailment). A coordinated and anticipating approach, allows avoiding repetitive action and, hence, increases inefficiency and acceptance.
- It may be impossible and / or not economically feasible to change the RoCoF response of all existing DG plants below 5 MW to the withstand levels specified in the current technical standards. As an additional option, dedicated rules for system operation and power plant dispatch might help to mitigate the risk of an unexpected loss of generation as a consequence of system frequency disturbances. Most likely such an approach will affect other fields of regulation (e.g. curtailment).
6 Appendix

6.1 Classification of used datasets and the quality of information derived

In the UK a single DG register covering major technical specifications does not yet exist. Therefore we used and integrated datasets from various sources. The data coverage, quality and volume differs between the different sources.

Ofgem, Renewables and CHP Register\(^5\)\(\text{a}\):

- General description: In the UK different support mechanisms exist in parallel. In general the generation stations must be accredited and registered by Ofgem, which provide public available datasets of the registered entries. In the analysis we considered datasets for the following instruments: Feed-In Tariff scheme (FITs), Renewable Energy Guarantees of Origin scheme (REGO), Renewables Obligation (RO) and Climate Change Levy (CCL).
- Volume: The consolidated number of entries is 545,000 representing an installed capacity of 54 GW (FIT: 530,000 with 2.7 GW; REGO: 14,000 with 46 GW; RO: 8,000 with 48 GW; CCL: 4,000 with 44 GW).
- Technologies: The datasets contain more than 70 different categories, which we consolidated to Wind off-shore, Wind on-shore, Photovoltaic, Gas and Bio and Hydro. In addition, we classified the performance class of the entries to focus on DG below 5 MW. For the analysis we used these datasets for Photovoltaic, Gas and Bio and Hydro. The analysis for wind is mainly based on the datasets of Renewable UK.
- Attributes: Ofgem publishes a limited set of attributes, which provides information on the geographical region (sometimes also in higher resolution via the postal code), the installed capacity of the accredited stations and date of commission of the registered generation station.
- General Remark: In comparison to other unit based registers, the Ofgem datasets cover the biggest volume of installed capacity, especially for small power units with few kW. Otherwise the published set of attributes is limited (e.g. lack of information on capacity per generation unit, geographical information in high resolution, date of decommission or status of the station and technical specifications like type of generator, connection point/voltage level or LOM settings). Furthermore a global unique identification key does not exist and the unclear definition of the registered unit (connection point or generator unit) make it difficult to compare the entries with other datasets and to ensure consistency.

\(^5\)\(\text{a}\) [https://www.renewablesandchp.ofgem.gov.uk/](https://www.renewablesandchp.ofgem.gov.uk/)
Renewable UK, UK Wind Energy Database\textsuperscript{51}:

- **General description**: Renewable UK registers information on UK wind energy projects of 100 kW and larger in a public available database. The unit based analysis for wind is mainly based on this database.
- **Volume**: In total, the database contains 6,000 wind turbines with an installed capacity of 12000 MW.
- **Technologies**: The datasets consists of wind on-shore and off-shore projects of at least 100 kW. Cumulated information on small wind projects below 100kW is published in the Small and Medium Wind UK Market Report (2013). Until the end of 2013 up to 100 MW of these small wind turbines were installed and about 50% of these power units were off-grid. Due to the minor capacity of on-grid generation and the lack of valid and unit based datasets small wind turbines are not considered in the detailed analysis of this report.
- **Attributes**: Renewable UK publishes a set of attributes, which provides information especially on the geographical location, installed capacity per turbine, name of the developer, date of commission and status of project.
- **General Remark**: In general, this database provides a comprehensive and consistent list of relevant wind projects and set of relevant attributes. However the dataset lacks technical information (e. g. manufacture, type of generator, connection point/voltage level, LOM settings).

Datasets of individual distribution network operator:

- **General description**: To operate their distribution network, the individual DNOs maintain internal databases of the connected generations in their system. Regarding this analysis Ecofys asked the six DNOs in GB to provide available datasets of distributed generation. The received datasets are confidential and their data is just presented on an aggregated level.
- **Volume**: In total, the received datasets contain around 25,500 entries of distributed generation units below 5 MW with a cumulated installed capacity of up to 1600 MW (representing around 30% of the population of distributed generation (<5 MW) in GB). Further statistical information for very small generators is given in an aggregated format. One DNO provided extensive information on power units and their attributes in his distribution network.
- **Technologies**: The datasets contain all investigated technologies.
- **Attributes**: In general, the individual DNOs register a comprehensive set of attributes for bigger distributed generation. However the provided datasets include a heterogenic range of attributes. Some datasets contain a full set of technical specifications (e. g. type of generator, connection point or LOM settings), some contain just basic information which is similar to the Ofgem datasets. The information of the connection point was just given in one dataset.
- **General Remark**: The DNO information selected for and assessed in the course of the study represents a limited sample. The data cover about one third of the cumulated installed capacity in GB. We focused on those datasets providing a comprehensive range of attributes, adding useful information to the various GB wide records. Accessibility of DNO data may

improve over time by more structural electronic database management. Recordings may be extended to small DG in the range between a few kW and 1 MW. Future analyses potentially will profit more from DNO data.

**Aggregated statistical data from DECC and EPIA**

- **Department of Energy & Climate Change (DECC):** To validate the installed capacity of renewable energy sources, Ecowys used the published reports Digest of UK energy statistics (DUKES) 2014\(^{52}\), which provide official data on the installed capacity of renewable energy sources in UK per technology in an aggregated format.

- **European Photovoltaic Industry Association (EPIA):** As Photovoltaic has a major share of distributed generation below 5 MW, we used official data from the GLOBAL MARKET OUTLOOK for Photovoltaics 2014-2018\(^{53}\) to validate the different datasets. A detailed national report on the market for PV in UK, like the Renewable UK market reports for wind, does not exist at the moment.

### 6.2 Sanity check data bases

None of the databases contains all plants and / or all information required. In order to validate the figures for GB we compared the composition of the data set provided by one DNO (Scottish and Southern Energy Power Distribution) with the respective subset of the national data for Scotland. The DNO represents about 80% of the DG in this part of the country and about 15% of the installed DG capacity. The bar graph at the right of Figure 14 shows that the shares of the technologies in the service area of SHEPD are sufficiently similar to the respective GB subset.

**Figure 14:** Database sanity check - comparison of data from SHEPD with respective subset for GB data

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These supportive findings for the technology mix in a particular region together with the high coverage of PV data in the FIT register covering the whole country (see section 2.2) indicate the completeness and consistency of the compiled datasets describing technology specific characteristics of DG in the GB system.

6.3 Update: Estimated growth of DG below 5 MW\textsubscript{el} since end of 2013

To provide a consistent and robust analysis, the inventory of the installed distributed generation (DG) in section 2 covered the timeframe up to the end of 2013. However, the situation in GB is characterised by a dynamic growth of DG, especially PV.

Therefore we analysed the capacity of power units below 5 MW\textsubscript{el} installed in 2014 according to the dataset of Ofgem for FIT and Renewable UK. We also included new power units which were commissioned between 31/12/2014 and 30/06/2015. The relative growth for each technology has been extrapolated and added to the validated capacity.

Compared to the end of 2013, extrapolation of data available to date suggests that DG below 5 MW\textsubscript{el} will grow by approx. 2 GW at the end of 2015 to a total of approximately 6.7GW. About 1.3 GW of this growth is solely attributable to PV, with PV capacity in this category growing from 2.6GW at the end of 2013 to 3.9GW at the end of 2015 (see in Figure 15). Overall, extrapolation suggests a 40% growth of DG and a 50% growth of PV in 2 years. Outside of PV, the main area of growth observed is onshore wind. We estimate a growth of onshore wind below 5 MW\textsubscript{el} from 700 MW at the end of 2013 to 1,200 MW at the end of 2015.

Figure 15 Estimation of the development of the installed capacity of distributed generation below 5 MW in GB, 2015*: estimation based on an extrapolation of available data between 31/12/2014 and 30/06/2015, sources: Ecofys, based on Ofgem, Renewable UK
6.4 System stability versus LOM protection – contradicting requirements?

During the last decade, Grid Code provisions in the UK were subject to changes due to the increased share of distributed generation in the instantaneous power balance. Similar developments took place in many other countries with growing DG populations. Nowadays, technical codes and standards require generators, including distributed generation, to support system stability and quality of supply. For DG at distribution level this is fundamentally new. In the past, distribution codes assumed a ‘window of normal operation’ and only specified requirements for intentional disconnection of distributed generation in case of abnormal conditions. Future distribution codes will include specifications for DG to stay during disturbances (as an illustration see Figure 16).

ER G83 already indicates that the generator’s capability to withstand RoCoF events in future might further increase. To withstand high RoCoF events is one requirement in the ENTSO-E codes and manufacturers have to take this into account already now while designing new components. Simultaneously, ER G83 suggests that such a high RoCoF withstand capability will conflict with reliable LOM detection and hence, RoCoF might not be allowed as a protection mechanism in future versions of the document. Similar considerations apply to vector shift and also to the domain of ER G59.

Similarly some other aspects related to supporting system stability may be perceived as contradiction to reliably detect loss of mains and avoid sustained unintended electrical islands. Selected issues are briefly described below.
- **High frequency response, ramping down active power output**

  Currently, in the GB system automatic frequency response is not required for generators being connected at distribution level. The GB Grid Code\(^{54}\) requires generators connected to the transmission system to be capable of reducing active power output automatically in case of overfrequency. The value of the active power gradient is subject to individual Ancillary Services Agreements. The example provided in the Grid Code corresponds to -20% of registered capacity per Hz in an operational range between 70% and 95% of the registered capacity of the generator (see Figure 17). This behaviour supports restoration of system balance and, hence, frequency, for example after a major loss of load.

![Diagram](image)

*Figure 17: Minimum Frequency Response Requirement Profile for a 0.5 Hz frequency change from Target Frequency, High Frequency response: red line (source: GB Grid Code)*

\(^{54}\) NGT, The Grid Code, Issue 5 revision 13, 22 January 2015
According to the GB Grid Code requirements the generator has to respond complete its response within 10 seconds. (The current draft version of the RfG published by ENTSO E\textsuperscript{55} requires generators to start to respond within 2 seconds.)

Basically, the response of power electronic converters is limited by the processing time of the control algorithm. For PV and wind energy converters time constants in the sub-second range are common. Assuming the algorithms implemented in the controllers of all distributed generators respond in a similar way, the plants behave virtually identical and, as a first order approximation, the complete DG fleet may be lumped to one large generator.

Acknowledging the growing share of distributed generation in the overall power balance, the RfG does not restrict frequency response to generators connected to the transmission level. Because of the legally binding character of the RfG within a few years respective requirements will be introduced at distribution level in the GB system too. In Germany active power droop in case of overfrequency was introduced for new installations in 2009 for medium voltage and in 2011 for low voltage.

The mechanism works fundamentally the same in electrical islands, for example after system fragmentation. DG compliant to this requirement tends to restore active power balance in unintended electrical islands with excess generation and, hence, might jeopardise frequency based LOM detection.

Still, active power ramping does not necessarily support sustained power operation of (sub-) systems. In reality, the control loops of distributed generators include various, design dependent dead times and time constants which in turn imply transient frequency (and voltage) oscillations of the concerned system. LOM detection is triggered fast (a few hundred milliseconds) and, thus, transients violating tolerances might immediately trip part of the generation. This further disturbs the power balance and, finally, results in the intended collapse of electrical islands.

- **Steady state voltage control**
  According to the GB Grid, Code transmission connected generation has to be capable of actively contributing voltage management at point of common coupling. At distribution level similar requirements have been introduced in other countries, but not for most of the GB distribution system yet (such requirements exist in Scotland). They are also specified in the draft of ENTSO E’s RfG.

  The GB Grid Code specifies that a generator’s control has to respond to a voltage deviation within 1 second\textsuperscript{56} or less. The speed of the control implemented by manufacturers may vary but, for stability reasons, will not be much faster than required. Hence, in practice corrective

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\textsuperscript{55} Commission Regulation ... establishing a network code on requirements for grid connection of generators (draft), ENTSO E, January 2015
\textsuperscript{56} Scottish system operators require a slower threshold of 5 seconds.
action from steady state voltage control is slower than the usual LOM detection mechanisms. From that perspective, it is unlikely that the introduction of steady state voltage control deteriorates the effectiveness of common anti-islanding concepts.

- **Transient voltage control and dynamic voltage support**
  Intentionally, transient voltage control responds faster. The GB Grid Code specifies a settling time of 2 seconds after an observed step change. Similarly, dynamic voltage support and reactive power injection in case of voltage depression (fault ride through) is expected to be activated in about hundred milliseconds or less. This immediate response results in a complex interaction of power flows in the affected circuits. Modelling and simulation studies with the realistic set of parameter for characterising the involved elements and devices are a precondition for reliably predicting the behaviour of the system of interest.

The reasoning above is highly qualitative and conditional. Still, much of the knowledge required for a thorough assessment of the interaction between system stability and effective LOM detection is lacking. While touching major questions of the subjects considered in this study, a comprehensive analysis of these aspects exceeds the scope. Further research is extremely valuable for elaborating future grid code requirements covering all system levels consistently.

### 6.5 Retrofit programmes in Germany – characteristics and experiences

**Ancillary Services Directive – SDL Wind V**
The ancillary services directive for WECs (Systemdienstleistungsverordnung Wind SDLWindV) was initially issued by the Ministry for the Environment, Natural Resources and Nuclear Safety in 2009. The purpose of the directive was to stimulate the improvement of technical capabilities of WECs to increase system stability in networks with further growing shares of wind generation. Essentially, the directive focused on three aspects:
- Provision of frequency support by wind farms
- Contribution to voltage control and reactive power management
- Voltage support and fault ride through capabilities in the event of network faults.

Respective capabilities have already been required by the Grid Codes of the 4 German TSOs since 2001. However, with very few exceptions, all WECs were connected to distribution networks. DSO codes required immediate disconnection in the case of transient voltage or frequency excursions. For new connections the MV Code of the German Electricity Networks Association (BDEW) applicable from 2009 removed the existing contradictions between transmission and distribution codes at this voltage level. However, about 25 GW of wind power had been installed until 2009, of which more than 10 GW had been installed after 2001. These existing plants potentially compromised system security until 2025 and beyond.

The technical requirements of the SDLWindV were similar to the MV code, but the ordinance applied to existing plants. Thus, SDLWindV helped to overcome the adverse effects of old and outdated connection requirements by reducing the affected capacity by up to 10 GW. Participation was voluntary and costs for the retrofit were covered by a bonus payment on the Feed-In-Tariff.
Curtailment – Renewable Energy Act 2012
Curtailment has been an explicit part of the Renewable Energy Act since 2004. At that time, mainly wind farms in MV distribution networks were subject to curtailment. Especially when the network capacity cannot evacuate all power under all conditions, temporary curtailment is used as an instrument to guarantee connection of RES-E. With the growth of DG capacity congestion of distribution networks occurred more frequently. Loading of MV distribution networks was influenced increasingly by DG operation at lower voltage levels, e.g. PV installations in rural areas. In 2013 about 1% of the total RES-E generation in Germany was curtailed. At that time it was already obvious that improved control of the DG fleet was essential for managing system balance, in particular in the case of contingencies and / or system restoration.
The renewable Energy Act of 2012 specified that all DG plants above 100 kW, regardless the technology, had to be equipped with facilities allowing bi-directional communication and remote control. I.e. the network operator had to be able to access operational data in real time and to curtail power output by an online signal. Plants in the power range of 30 to 100 kW also had to be equipped with technical interfaces for remote control. Feedback of online data to the network operator, however, was not mandatory. PV plants below 30 kW were free to choose between remote control and permanent curtailment at 70% of the peak capacity of the PV modules. The additional bi- or unidirectional communication and control interfaces had to be installed by the plant operators at their own costs. The requirements applied also to existing plants above 100 kW and to plants in the range from 30 to 100 kW if they were installed after the end of 2008.

System Stability Directive – SysStabV (I)
The VDE V 0126-1-1 product standard for (PV) inverters introduced a major change of grid code requirements applicable to this particular technology. PV plants connected to LV networks had to cease generation at any network frequency above 50.2 Hz. Compared to the previous setting of up to 51.0 Hz this was a substantial reduction of the operational range. At the time these new settings became obligatory, about 1.7 GW of PV capacity existed. When the Medium Voltage Code was pre-published in mid-2008, about 5 GW of PV installations were operating in Germany. More than 80% of this capacity was small-scale and connected to LV networks. More than 2.5 GW of PV generation had been installed under the regulations of the product standard and would immediately disconnect from the system at a moderate frequency excursion of +0.2 Hz. Starting from 2012 the application note VDE-AR-N4105 formally adjusted the settings to 51.5 Hz for all future plants. By then the PV capacity with 50.2 Hz protection settings had grown to more than 17 GW.
The existing plants represented a permanent risk for secure operation of the ENTSO-E system. Similar corrective measures for this '50.2 Hz issue' were inevitable and have been regulated by the System

57 Similar concerns applied to other EU countries with significant PV capacities and same protection settings, e.g. Italy, Belgium and the Czech Republic. Italy started a retrofit programme at about the same time as Germany. In this country, however, the PV market is dominated by a limited number of large PV plants. This made it easier to execute the retrofit and, accordingly, the activities were completed within about one year.
Stability Directive (Systemstabilitätsverordnung SysStabV) issued in 2012. The objective of the Directive was to substantially reduce the affected capacity in an ambitious timeframe. In order to avoid unnecessary costs, the directive applies only to PV plants with a rated converter capacity of 10 kW or more (cumulative over all inverters in one plant). For technical reasons, adjustment of some types and models was impossible. Still, more than a million PV inverters had to be updated with new protection settings in the course of the retrofit programme. In most cases, adjustment required active support by the manufacturer. DSO’s were responsible for managing execution of the programme in their supply area and the cost were socialised via the DSO’s network charges.

From a technical perspective, this programme is similar to an adjustment of RoCoF settings in the GB system as long as such an exercise would be restricted to PV.


Already in an early stage of assessing the impact of the ‘50.2 Hz issue’, it became clear that also under-frequency settings of DG in Germany could pose a problem. The distribution codes required all DG technologies including CHP to cease feeding in power when system frequency dropped below 49.5 Hz. The affected capacities are even higher than in the case of PV. Currently in Germany, more than 25 GW are installed with this setting, of which about 10 GW each of wind power and CHP, will disconnect at 49.5 Hz. Obviously such an instant loss of generation, in particular in case of generation deficit, would be fatal for system stability.

In March 2015 the German Ministry of Economics and Energy enacted an extension of the SysStabV. The target is to reduce the capacity with critical settings to maximum 1 GW. All stakeholders acknowledge that this is an extremely ambitious target. The retrofit campaign will address slightly more than 20,000 generators with a nameplate capacity of 100 kW or higher.

In most cases, simple adjustment of the settings of the frequency protection relay will be sufficient to remove the risk of undesired loss of generation. In a number of cases however, more complex adaptations of the plant might be required. There will even be cases were an adjustment to the target value of 47.5 Hz at reasonable cost is impossible because of technology restrictions. Even after extensive stakeholder consultations, it is difficult to estimate the total volume and the specific restrictions related to those more complicated cases in advance. Hence, for an unknown number of plants, an individual assessment of retrofit options and suitable protection settings will be required. This is one of the most challenging aspects of this campaign.

From a technical perspective, this programme is closest to a potential adjustment of RoCoF settings for all non-PV technologies.

**Similarities of and differences between the retrofit programmes**

The programmes had very different technical backgrounds and financial implications. Accordingly, the processes and regulative arrangements varied. Some aspects are briefly discussed below.

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58 Already earlier, the frequency protection settings of more than 12 GW of wind power, participating in the SDL WindV, were adjusted to appropriate values.

59 Similar concerns apply to other EU countries with significant DG capacities and similar protection settings, e.g. Austria, the Czech Republic, France, Greece, Switzerland and Portugal. In most of these countries activities still have to be started.
All programmes were legally regulated by the federal government. The programmes implied duties for various stakeholders as well as reimbursement and socialisation of costs. In order to create a consistent and reliable framework for execution, the government issued legally binding ordinances and laws, defining timeframes, allocating responsibilities and costs.

Most programmes have been obligatory. Only SDL WindV was voluntary and was stimulated by a bonus payment. In case of the other programmes plant operators were legally forced to collaborate. Lack of collaboration would result in penalties, the most common being suspension of the Feed-In-Tariff payments.

Responsibility for programme execution differed. As a voluntary programme, SDL WindV left the responsibility for planning and managing the retrofit with the plant owner. Plant owners were also responsible for purchasing and installing the equipment for curtailment on time. They had to report successful implementation to the DSOs. In the case of SysStabV, the situation is more complex. Maintaining secure system operation is the statutory task of the TSOs. However, the first point of contact for DG operators is the DSO. For this reason, in the case of SysStabV (I), the Ministry appointed the DSOs as being responsible for managing and executing the retrofit process. The TSOs monitored progress based on the data provided by the DSOs. The DSOs in turn had to hire and compensate third parties (installers) to perform the actual work. This multi-level communication and management structure proved to be complicated and subject to inefficiencies. In the case of SysStabV(II), process responsibility will be allocated to the TSOs. However the DSOs will still actively participate in programme execution because they are the contractual partner of the plant owners and operators.

Equipment manufacturers (WECs, PV inverters, etc.) actively supported the respective programmes but had no formal responsibility. In fact, the way how they contributed to the retrofit activities was not subject to regulation.

Cost of most programmes have been at least partially socialised. This was a pragmatic policy choice in order to support acceptance of the required activities at the side of the affected stakeholders. Socialisation is obvious for a voluntary, bonus driven programme like the SDL WindV. In this case a per kWh bonus – on top of the feed-in tariff – covered investments. The annual cost in the order of magnitude of 100 million Euro became part of the renewables levy and, hence, are paid by the electricity users. The cost for adjusting the frequency protection settings of PV inverters under the SysStabV I have been covered more or less completely and included in the DSO’s network charges. The total programme will cause costs of some 100 million Euro. The cost for adjusting protection settings of the other technologies (SysStabV II) remain with plant owner. The specific costs, however will be capped at a maximum of 7.50 € per kW nameplate capacity. Costs to be socialised will probably be significantly lower than for the programmes mentioned above.

Purchase and installation of the equipment for curtailment was completely left up to the plant operators and costs were not reimbursed.

The issues to be tackled were and are urgent and, consequently, planning was ambitious.
The period for executing most of the programmes was about 2 years. Only the time frame for SDLWindV was longer and was extended to 5 years in order to allow more wind farms to be modified under the programme.

Coverage of the programmes varied.

Apparently all relevant plants formally comply with the requirements for allowing curtailment. The retrofit of PV inverters under SysStabV (I) covered more than 80% of the originally anticipated population. In a number of cases, manufacturers’ analyses during the ongoing retrofit revealed that modification of some models is impossible. Consequently, the capacity with the original 50.2 Hz settings in the end will be slightly higher than anticipated. Similar issues will certainly appear when retrofitting the other DG technologies with respect to under-frequency protection settings under SysStabV (II). At this moment it is nearly impossible to provide a qualified guess regarding the share of the addressed capacity which in the end will not be retrofitted due to technology restrictions.

Participation in SDL WindV depended on the outcome of a cost benefit analysis by the individual plant owner. Depending on the manufacturer and model, the investment for the additional equipment varied. On the other hand, the benefit depended on the remaining technical life and the site specific yield. Finally, participation was also limited by contingencies at the side of manufacturers and certifying bodies. The share of upgraded capacity is at about 60% to 70% of the technical potential.

The achieved improvement of compliance is not completely clear.

In the course of the SDL WindV-retrofit results have been verified by certification. Compliance with the specified capabilities had to be confirmed by independent assessments on a type test level (individual WECs) and by modelling calculations (wind farm level). This approach guarantees that the desired results indeed were achieved. The cost of this approach were substantial but reasonable compared to the total investment per WEC. Additionally, the specialist resources required for certification determined the total period required for the SDL WindV process.

Because of urgency and differing cost structure such an extensive quality control process has not been included in SysStabV(I). Also compliance of the control equipment for curtailment has not been verified on a plant-by-plant basis. DNO’s individually decided on the structure and depth of quality checks. Reported samples indicate that the intended improvement is not always achieved. Individual stakeholders estimate the rate of incorrectly performed adjustments at about 10% to 20%.

The vital importance of successful execution of the programmes for power system security has been acknowledged. For that reason, ex post quality checks will be an integral part of the requirements formulated in the extension of SysStabV (II). Methodologies, selection and evaluation criteria still have to be defined by the network operators.

All retrofit actions represented a compromise.

For obvious reasons the programmes focused on selected, highly important characteristics. They consciously accepted that not all technology features could be updated to the state-of-the-art. As one example, while adjusting frequency protection, the required active power droop in case of overfrequency has not been retrofitted in the individual units because of excessive costs. Instead, at system level a similar behaviour has been emulated by
distributing cut off frequencies within the complete population evenly in the range between 50.3 Hz and 51.5 Hz. All programmes also accepted that part of the plant population would not be updated at all.

From a LOM perspective this approach offers a potential advantage. In small network sections or electrical islands frequency response becomes disruptive because units switch off successively at discrete frequency values. This behaviour by nature disturbs power balances and, hence, is less stable. The original 'compromise' might be worth considering even for future overfrequency requirements.