Mitigation of PQ Disturbances and Provision of Differentiated PQ

Deliverable 5.5

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Executive summary

This report documents the work that has been carried out from June 2018 to December 2019 by MIGRATE WP5 (Power Quality in Transmission Networks with high PE Penetration) under task 5.5. The report constitutes the deliverable D5.5 – "Mitigation of power-quality disturbances and provision of differentiated PQ", in fulfilment of the requirements defined by the grant agreement N0 691800.

In line with the European Electricity market policy, more and more renewable sources are being connected to the grid, including on high voltage transmission levels. The renewables are often connected to the grid by the means of power electronic (PE) instead of synchronous machines. This trend is expected to grow in the future, increasing penetration of PE devices, or alternatively, system non-synchronous penetration (SNSP). When SNSP increases, power quality is expected to deteriorate.

The WP5 of MIGRATE project is focusing on research regarding the power-quality issues with the increase of SNSP. In previous tasks, critical aspects of power quality were evaluated and presented in the deliverable D5.1. As the report suggests, the main concerns arising from the increasing SNSP are in the areas of harmonic distortion and power fluctuations causing voltage and frequency variations in the grid. Those two aspects were further analysed in the following tasks of the MIGRATE WP5. The power quality analysis was based on three steps. First step was to develop adequate models of PE devices in order to investigate their impact on future transmission grid. Several PE devices were included in the study, among them HVDC systems, static compensator, static-var compensators, wind-turbine generators solar photovoltaics and battery storage. For each device, three types of models with different level of detail and complexity have been developed: the electromagnetic transient (EMT) model, the average RMS model and the harmonic load-flow model. The EMT model is used for detailed representation of device behaviour and is then further simplified to average RMS model to be used in time-domain studies of power fluctuations and harmonic load flow model to be used in harmonic emission propagation studies. This research is described in deliverable D5.2.

In deliverable D5.3 research about methodologies for PQ studies is presented. Two methodologies were developed – one for frequency and voltage fluctuations studies and the other for harmonic propagation studies. Those methodologies were tested and proved on the test networks and were then in deliverable D5.4 applied to the modified model of Irish network. The actual Irish grid model was modified in order to simulate the penetration of PE devices up to 90%. With this study, future levels of power quality without any mitigation measures were investigated. As the report mention, the standard deviation of the system frequency increased by 145% for a case with 90% PE penetration compared to reference case of 60% PE penetration. Furthermore, the amount of balancing energy relative to the installed capacity of remaining synchronous generators increases by 200% for the same scenarios. On the other hand, no significant issues with voltage variations were detected due to the fact that PE devices, connected to transmission level feature voltage control. The same study also focused on harmonic distortion using the same modified Irish grid models with the PE penetration from 60% to 90%. For 90% PE penetration, 4% of 110 kV network busses suffered
total harmonic distortion above 3% while on the other busses THD was largely increased, however still below the 3% limit.

In the deliverable D5.5, the research of frequency variation and harmonic distortion mitigation measures is presented.

Mitigation of Frequency variations

The unsteadiness and intermittent nature of renewable power sources lead to higher fluctuations of the generated power. In power systems with a high share of renewable energy sources (RES), fluctuating power feed-ins have a strong effect on the system frequency resulting in significant frequency deviations from the nominal value. At the same time, the replacement of the directly coupled synchronous machines by the PE-interfaced generation could further increase the frequency variations due to the reduced system inertia. Therefore, frequency variations might limit the expansion of PE penetration in transmission grids.

Within MIGRATE WPS, wind turbine advanced power command synthesizer for mitigation of frequency variations was developed. The mitigation method is realised by modifying the active power control design of the generator side converter in order to utilise the kinetic energy stored in the rotor of the wind energy conversion system (WECS). In the case of under-frequency, kinetic energy is released, and vice versa. All stability limits of the wind turbines are considered in order to achieve the safe operation.

The developed power control algorithm was added to wind turbines included in the case study of the modified Irish grid with PE penetration of 90% in order to evaluate the mitigation measure efficiency. The results of the study revealed, that a standard deviation $\sigma$ was 46.2 mHz in the case of normal maximum power point tracking (MPPT) operation of wind turbines and 15.4 mHz when the proposed method for the mitigation of frequency variations was activated. This corresponds to a 66.67% reduction in the standard deviation with the proposed method. At the same time, the variation of the power generation of the wind turbines was significantly decreased – this corresponds to the fact, that the wind turbines themselves are the major cause for frequency variations. Moreover, the energy loss due to non-MPPT operation of the wind turbines was only 0.01%.

Mitigation of Harmonic Distortion

Harmonic distortion is an important aspect of PQ phenomena. It is usually defined as a sinusoidal voltage or current waveform with frequencies that are integer multiples of the fundamental frequencies. The main causes of harmonics distortion are non-linear loads and devices supplied with switch-mode power supplies, and more recently from power electronic (PE) interfaced generators. It is also worth mentioning that "traditional devices" like power transformers are also contributing to harmonic distortions in the network, though to a lesser extent than power electronics interfaced
generators, loads, HVDC lines and FACTS devices. The combination of all of these devices is certainly contributing to growing concerns about harmonic distortion in power transmission networks.

The mitigation of harmonic distortion can be approached from two directions – first approach is to decrease the harmonic emission level of the devices themselves and the second approach is focused on system-wise mitigation by installing filters or other mitigation devices at the appropriate places in the network. MIGRATE WP5 evaluated both approaches.

In order to evaluate the possible improvement of the PE devices regarding the emission of harmonics a detailed study was performed based on the EMT models of the PE devices. The following improvements were evaluated: With Statcom device, the self-compensation harmonic mitigation solution has been implemented. Several harmonic control loops have been added and the harmonics emission has decreased significantly. With PV/battery-generation units, complex second-order or even third-order (LCL-filter) filter was added to achieve significant improvements, however for slightly higher cost compared to software solution for Statcom device. For Static Var Compensator (SVC), case-by-case approach is recommended. Special care should be taken to deal with introduction of several resonant points due to connection of additional passive filters.

For the system-wise approach, the methodology of harmonic propagation study, presented in deliverables D5.3 and D5.4 was used. However, the methodology was extended by adding the optimisation algorithm to decrease the harmonic distortion. The optimisation algorithm detects the most effective locations in the network for installing the passive filters and tries to add different solutions from a pre-defined pool of compensation devices (e.g. passive filters or PE device mitigation), until the optimal solution is achieved. The optimisation can be performed globally or zonally, i.e. with different total harmonic distortion limits in different zones of the network. Using the optimisation algorithm, network-based mitigation (e.g. passive filters) was proven to be more effective compared to mitigation approach using PE devices improvement to lower the emissions of harmonics.

Additionally, economical aspect of harmonic distortion mitigation was added into the research in a form of a new techno-economical harmonic mitigation methodology. In the methodology, the financial consequences of harmonic mainly include three aspects: energy/power losses, losses due to premature ageing and losses due to equipment malfunction. On the opposite side there is the cost of investment and maintenance of harmonic mitigation solution. The results of techno-economical optimisation show the advantage of the network based mitigation, which is able to bring harmonic performance well under the specified thresholds and greatly reduce the potential economic losses resulting from the presence of the high level of harmonics. It should be noted though that the parameters used in optimisation could greatly affect the final results and a special attention should be given to selecting appropriate technical and economic parameters used in the optimisation.
Final recommendations

With the extensive research within the MIGRATE WP5, we can make the following recommendations in order to keep the desired levels of power quality at higher penetration of power electronic devices in transmission networks:

1. We propose to use probabilistic approach to harmonics mitigation since taking into account the uncertainty of harmonic emission as well as future scenarios enables more future-proof solutions. The operating point clustering can significantly decrease calculation effort and thus enable the optimization algorithm to effectively find an optimum solution for harmonic mitigation of the large transmission networks.

2. Further research work is recommended to identify in a holistic manner the most robust and cost-effective global harmonic mitigation approach for transmission systems. This should take into account a wide set of scenarios including ancillary aspects such as regulatory, cost recovery mechanisms, risk assessment, responsibility/accountability for data accuracy, as well as additional system impacts associated with multiple filter deployment. For robust results of such research a careful identification and full engagement of stakeholders will be required.

3. We propose the use of new wind turbines control algorithm, which significantly reduces the frequency variations, is easy to implement in (existing) wind turbines and only minimally reduces total energy output.

4. We propose to create new or modify the existing balancing service, focusing on frequency variations mitigation using wind turbines in order to significantly reduce the stress on existing primary and secondary regulation sources by greatly reducing the frequency variations.

5. It is recommended to develop a common power quality legislation between neighbouring countries/systems. This will enable balanced allocation of power quality headroom for different customers, minimize possible future costs related to power quality mitigation and guarantee optimal system development.
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1 Introduction

With the increasing trend towards renewable energy sources (RES), the penetration of power generation from RES is continually rising in the European transmission systems [1]. This goes along with an increased number of power electronic (PE) conversion devices connected to the grid. At the same time, many types of flexible AC transmission system (FACTS) devices and an increasing share of controllable loads comprise power electronics [2].

The increasing penetration of PE-interfaced generators and devices is expected to pose challenges to the development and operation of the European transmission systems in the future [3]. One of the major concerns from the proliferation of PE-interfaced generators and devices is the degradation of power quality (PQ). When it comes to power quality, most important factors to maintain are frequency constancy, voltage constancy and reliability of the power supply [4]. These factors are strongly affected by the intermittent nature of renewable energy sources (RES). More specifically, the fluctuating power feed-in from distributed RES, like wind and photovoltaic power plants, lead to frequency variations in the system [5, 6]. These frequency variations are further aggravated by the decreased system inertia as more and more traditional synchronous generators are being replaced by PE-interfaced generators [7]. Since the synchronous generators are also used for voltage control in power systems, their replacement necessitates voltage support from PE devices for maintaining system voltages within their acceptable limits [8].

Another main concern, from the proliferation of PE devices, is the harmonic emissions that are generated from the nonlinear switching converter based elements and are affected by the critical network impedances. The harmonic phenomena may result in thermal stress of insulation, interferences to communication infrastructure, increased power losses, and mal-function of switchgears and devices [3]. Furthermore, the harmonic phenomena may propagate to other parts of the network, or develop into more severe resonance conditions. With the increased and widely distributed harmonic injection sources, regulatory bodies have acknowledged the importance of harmonic performance improvement, and a number of standards have specified the required harmonic performance, e.g., IEEE 519 [9]. On the other hand, deteriorated PQ can also considerably effect the life-time expectancy of the PE devices and their efficiency during operation [9].

Since the route to adequately improving the PQ begins with identifying the source of the issues, a comprehensive study considering the influence of PQ disturbances on operation of PE rich power networks was done in Deliverable D5.4 [9]. The work in [9] concluded that it is necessary to mitigate the PQ disturbances expected in future transmission networks. In the present deliverable, methods for mitigating the foreseen PQ disturbances of the future transmission systems are provided. The introduced mitigation methods are targeted towards two major aspects of PQ, namely the frequency variations and the harmonic distortion.
To address the issue of frequency variations, a mitigation method is realized through wind energy conversion system (WECS). The developed mitigation method utilises the kinetic energy stored in WECS to significantly mitigate the frequency variations in a power system. With regards to harmonic distortion, a variety of harmonic mitigation strategies including device-based harmonic mitigation and central harmonic mitigation are provided. The various mitigation approaches are investigated in an optimisation and a probabilistic framework to find the optimal mitigation solution zonally and globally taking into account both technical and economic aspects. The mitigation methods will be assessed through simulations and studies to rate their ability in keeping the investigated PQ parameters within expected or technically required levels.

Beside the aforementioned mitigation methods, this document will shed light on the current practices performed by the European transmission system operators (TSOs) for managing the PQ in the transmission system as well as the current PQ legislation in Europe. Based on the prior data, recommendations will be issued for future PQ management.

The document is organized as follows. Following this Introduction, Section 2 will present the contribution on the mitigation of frequency variations. Mitigation of harmonic distortions is addressed in the subsequent Sections 3 and 4. The device based mitigation of harmonic emissions is discussed in Section 3 while the system-wise approaches for mitigating the harmonic distortions are elaborated in Section 4. In Section 5, the European practice on power quality management is presented and recommendations for power quality management are offered as well. In Section 6, conclusions are given.
2 Mitigation of Frequency Variations

2.1 Motivation

The unsteadiness and intermittent nature of renewable power sources lead to higher fluctuations of the generated power. In power systems with a high share of renewable energy sources (RES), fluctuating power feed-ins have a strong effect on the system frequency resulting in significant frequency deviations from the nominal value [9]. At the same time, the replacement of the directly coupled synchronous machines by the PE-interfaced generation could further increase the frequency variations due to the reduced system inertia. Therefore, frequency variations might limit the expansion of PE penetration in transmission grids.

It is still possible, however, to mitigate such frequency variations by introducing new developments into power converters control of the PE-interfaced generation. Since the penetration of wind energy is continually increasing in the European power systems [10], wind power plants should be involved in mitigation of frequency variations in the future. Besides, wind power plants in particular are characterised by a fluctuating power feed-in, causing the frequency variations themselves.

The objective of this work is to model a method for controlling wind energy conversion systems (WECS) to mitigate the frequency variations and thereby enable system operation for high share of PE interfaced generation. The mitigation method will be assessed through simulations to rate its ability in keeping the frequency variations within the admissible limits.

Following this Motivation, Section 2.2 will present the literature review. A wind farm model in the simulation software PowerFactory DiGSIILENT is developed in Section 2.3. The development and implementation of the proposed mitigation method is explained in Section 2.4. The grid model which is based on the transmission system of Ireland is given in Section 2.5. In Section 2.6, the operating points of the validation setup are specified to enable studies for validation of the effectiveness of the mitigation method. Results of the studies are presented and discussed in Section 2.7. In Section 2.8, conclusions are given.

2.2 Literature Review

In order to enable system operation for a high share of PE-interfaced generation, mitigating the frequency variations is necessary. Frequency variations primarily depend on active power variations. Since wind energy conversion systems (WECS) are characterized by their fluctuating power feed-in, the work in [11-22] focused on smoothing WECS output power to mitigate the frequency variations.

In the aforementioned literature, two approaches for power smoothing of WECS are considered. In the first approach, energy storage system (ESS) devices such as batteries or flywheels are utilized to mitigate the wind power fluctuations [11-13]. Although the utilization of ESS could smoothen the
power from wind without influencing WECS control, equipping WECS with ESS involves additional investments [11].

The second approach achieves smoothened power by modifying the control of WECS. An advanced pitch control method for wind power smoothing is presented in [14]. A main demerit of the pitch control is the decreased power production of the turbine when operating below the rated wind speed. Other power smoothing schemes utilize the kinetic energy stored in the rotating mass of a WECS [15-22]. More specifically, the mitigation of the output power variations is achieved by storing and releasing kinetic energy in the rotating mass of a WECS via rotor speed acceleration or deceleration. When compared with other power smoothing methods, this method is considered to be promising since it does not require power curtailment or supplementary devices [15]. The amount of kinetic energy that can be extracted, however, is constrained by the turbine’s rotational speed and torque limits. Exceeding these limits might lead to instable operation of the WECS. This will cause the turbine to stall [16].

In [16], a strategy to control a wind turbine to deliver averaged power output by means of a moving average filter and thereby alleviating the fluctuating power component is discussed. The method requires reliable real-time wind speed measurement to estimate the optimal rotor speed command and thereby ensure the stable operation of the wind turbine.

For absorbing the faster fluctuations of wind speed and acquiring a smoother power output, a low-pass filter is implemented on the rotor speed measurement in [17] [18], and on the maximum power point command in [19]. Yet, an inappropriate selection of the filter time constant will increase the wind power losses due to the worsened MPPT performance and might also lead to instability of the closed-loop speed control or the closed-loop power control.

In order to smoothen the power output, literature [20] and [21] proposed to integrate a supplementary control loop based on frequency deviations into existing converter power control loop. The supplementary control loop is inspired from primary control structures and its effectiveness to mitigate frequency variations remains limited without a power reserve through the de-loaded control.

In [22], wind turbine is controlled to deliver constant power output corresponding to the average wind speed and thereby omitting the effect of the fast wind speed variations. This strategy is difficult since it requires reliable wind speed prediction, whereas inaccurate forecast could lead to instability of control. The proposed method for the mitigation of frequency variations does not require wind speed prediction nor does it require wind speed measurements. The proposed method can be implemented without the need of additional storage devices.

### 2.3 Wind Farm Modelling

In this section, a wind farm model in the simulation software PowerFactory DgSILENT is developed. The simulation software is chosen based on the grid model provided by the Irish transmission system
operator (TSO) EirGrid. Each wind farm comprises a number of type-4 wind turbines. The full converter wind turbine employs a permanent magnet synchronous generator (PMSG). This design is chosen since it is gaining popularity, particularly in offshore applications [23]. The frequency converter consists of the generator-side converter and ac-grid side converter, both coupled via dc-link. Under normal operation, the PMSG and the ac-grid can only exchange active power and not reactive power through the DC-link. Therefore, the control of active power output of wind energy conversion system (WECS) usually occurs at the generator-side converter for the suggested configuration. On the other hand, the control of reactive power in-feed and voltage occurs at the grid-side converter.

For the scope of this work, in investigating the frequency variations, it was shown in MIGRATE Deliverable D5.2 that the effects of high-frequency electromagnetic transients and harmonics may be neglected in the system modeling [24]. Hence, neglecting the switching effects of the converter and the DC-link transients is valid for this work. In the model, a wind farm is interfaced to the grid through a single grid-side converter.

In the following section, the modeling of the generator-side of the WECS covering turbine, PMSG, and generator-side power electronic converter is described at first. Then, the coupling of the WECS to the grid through a model of a voltage sourced converter is explained.

2.3.1 Generator-Side Model of Wind Power Conversion

The block diagram description of the generator-side model of the considered WECS is given in Figure 2-1. The model is developed for PowerFactory simulations and is used to represent the turbine, PMSG, and generator-side power converter together with their controls. The wind speed velocity \( V_w \), acting on the turbine in the drive-train model, generates a mechanical accelerating torque on the shaft. The electromagnetic torque \( T_e \) coming from the PMSG will try to counterbalance the latter by creating a decelerating effect on the shaft as the PMSG delivers electric power \( P_e \) to the converter. The delivered power \( P_e \) is compared with the power reference \( P_{\text{ref}} \), issued by the power command synthesizer, at the input of the power controller. The power controller provides the electrical torque reference to the inner-loop current control, which in turn regulates the electromagnetic torque \( T_e \) of the PMSG. The configuration is decomposed into three functional stages: 1) current controller and electromagnetic stage; 2) drive-train model; and 3) power -controller, power -synthesizer and the calculation of the maximum electric power that can be transferred over the air-gap of the PMSG. The air-gap of the PMSG is the distance between the outside diameter of the rotor and the inside diameter of the stator. In the following three subsections, the functional stages are explained.
2.3.1.1 Current Controller and Electromagnetic Stage

By considering existing literature knowledge, the current controller together with the electromagnetic stage is approximated with first order element which is characterized by the time constant $\tau_i$ of the current control loop [2] [25] as shown in Figure 2-2. The electromagnetic stage comprises the PMSG dynamics as well as the generator-side power converter dynamics. Figure 2-3 shows the simplified compact form of the current control loop together with the electromagnetic stage as implemented in the PowerFactory model. This compacted form holds the dynamic of the current controller while neglecting the algebraic conversions from torque to current and vice versa since these conversions do not produce any time delays. The design parameter $\tau_i$ is usually specified in the range of 0.5-5 ms [2].

\[
T_{\text{e,ref}} \xrightarrow{\frac{1}{1 + ST_i}} T_e
\]

Figure 2-2: Block diagram of the compacted current controller and electromagnetic stage.

\[
\frac{1}{1 + ST_i}
\]

Figure 2-3: Compacted current controller and electromagnetic stage implementation in PowerFactory DlgSILENT.

2.3.1.2 Drive-Train Model

For representing the turbine-generator interaction process in the PowerFactory WECS model, a single mass drive-train model is implemented. The interaction between the turbine and the generator for a single mass drive-train model is described by (2.1):

\[
\int \frac{2 \, d\omega_e}{p} = T_{\text{tur}} - T_e - T_d
\]  

(2.1)
where $J$ is the turbine inertia, $p$ is the number of poles of the permanent magnet synchronous generator (PMSG), $\omega_e$ is the electrical angular velocity of the rotor, $T_{\text{tur}}$ is the aerodynamic torque, and $T_d$ is the turbine damping coefficient.

The damping torque due to friction is

$$T_d = D \frac{2}{p} \omega_e$$

(2.2)

The aerodynamic torque $T_{\text{tur}}$ of the wind turbine is given by (2.3):

$$T_{\text{tur}} = \frac{1}{2} \pi \rho r^3 V_w^2 C_T(\lambda)$$

(2.3)

with the tip speed ratio

$$\lambda = \frac{2 \omega_e r}{p V_w}$$

(2.4)

where $\rho$ is the air density, $r$ is blade length and $C_T(\lambda)$ is the torque coefficient.

Figure 2-4 shows a typical torque coefficient $C_T(\lambda)$ curve and power coefficient $C_P(\lambda)$ curve for the investigated wind turbine model. The two coefficients are related by $C_T(\lambda) = C_P(\lambda)/\lambda$. The optimal tip-speed-ratio $\lambda_{\text{opt}}$ for a given wind turbine is considered constant and can be found at the maximum of the $C_P$ curve. For the tip speed ratio $\lambda$, there is a value below which the torque coefficient $C_T(\lambda)$ increases for increasing $\lambda$. This region is found for $dC_T(\lambda)/d\lambda > 0$. Operating in that region could lead to instability issues [25]. In contrast, the region of stability is located at the falling slope of the torque coefficient $C_T(\lambda)$ where a positive change of the rotor speed $\lambda$ leads to negative change in $C_T(\lambda)$. Therefore, operating points are preferred in the region of $dC_T(\lambda)/d\lambda < 0$.

Figure 2-5 shows the implementation of the drive-train model in the PowerFactory DIgSILENT. The torque coefficient $C_T(\lambda)$ values are based on the $C_T(\lambda)$ curve of Figure 2-4, and have been stored into a lookup-table for fast online access.
2.3.1.3 Power Controller and Synthesizer

In what follows, the PowerFactory models of the power-controller, power-synthesizer as well as the calculation of the air-gap power are presented. The design of the aforementioned models aims at maximising the energy capture for a given wind speed profile while also ensuring a stable operation of the WECS.

**Power controller**

The power controller design, shown in Figure 2-6, is adopted from [25]. The author suggests an integral plus a lead-lag controller to compensate the turbine-rotor dynamics of WECS through pole zero cancellation. These dynamics are represented by lagging behavior seen between step in torque and change in rotor acceleration and a leading behavior of a change in electrical power as response to a change in the electrical torque. Figure 2-7 shows a block diagram of the power controller as
implemented in PowerFactory DIgSILENT. The controller parameters are calculated as a function of WECS parameters and the operating point [25].

\[ P_{e,\text{ref}} = \frac{K}{s} \left( 1 + \frac{s \tau_m}{1 + s \tau_z} \right), \]

Figure 2-6: Block diagram of the power controller.

\[ P_{e,\text{ref}} \]
\[ P_e \]

\[ \frac{K}{s} \]
\[ 1 + \frac{s \tau_m}{1 + s \tau_z} \]

\[ T_{e,\text{ref}} \]

Figure 2-7: Power controller implementation in PowerFactory DIgSILENT.

**Power command synthesizer**
The power-command synthesizer issues the power reference which defines the operating point \( P_{e,\text{ref}} \) of the WECS model. In order to increase efficiency, the power reference should be set to equal the maximum power that can be extracted from the wind \( P_{\text{MPP}} \).

\[ P_{e,\text{ref}} = P_{\text{MPP}} \quad (2.5) \]

The maximum extractable power from the wind is dependent on the wind speed \( \nu_w \) and maximum power coefficient \( C_p(\lambda_{\text{opt}}) \)

\[ P_{\text{MPP}} = \frac{1}{2} \pi \rho r^2 \nu_w^3 C_p(\lambda_{\text{opt}}) \quad (2.6) \]

where \( \lambda_{\text{opt}} \) is the optimal tip speed ratio.

With (2.4), equation (2.6) is expressed at \( \lambda_{\text{opt}} \) as the optimal regime curve:

\[ P_{\text{MPP}} = \frac{4}{3} \pi \rho r^2 \frac{C_p(\lambda_{\text{opt}})}{\lambda_{\text{opt}}^3} \omega_e^2 \quad (2.7) \]

Hence, the maximum power point tracking is enabled based on the electrical angular velocity \( \omega_e \) measurements as shown in Figure 2-8. Furthermore, the operation in the preferred region of \( dc_T(\lambda)/d\lambda < 0 \) is ensured with the power command synthesizer, since the maximum power point lies within the preferred region.
Calculation of air-gap power
To close the power loop, the air-gap power $P_e$ as depicted in Figure 2-1 is calculated and fed back to the controller. The air-gap power is the maximum electric power that can be transferred over the air-gap of the PMSG. When neglecting electrical power losses, the air-gap power becomes equal to the power delivered over the terminal of the PMSG. The air-gap power $P_e$ is given by the multiplication of torque and speed [25]. The former is fed from the current controller and electromagnetic stage while the latter is obtained from the drive-train model.

$$P_e = \frac{2}{p} T_e \omega_e$$  \hspace{1cm} (2.8)

Since the switching operation of the converter and DC-link transients are excluded in the PowerFactory model, it is safe to assume that all air-gap power of the PMSG, $P_e$, is fed to the grid side converter when neglecting the power losses.

2.3.2 Grid-Side Converter Model of Wind Farm
So far the generator-side model of the investigated WECS model is derived. The model aimed at maximizing the wind energy capture. In order to exchange the captured power with the grid, the WECS model derived in Section 2.3.1 should be connected to the PowerFactory grid model. To connect all WECS models in the wind farm to the grid, one voltage sourced converter model (VSC) is used. More specifically, it is assumed that the PMSGs of the wind turbines are all connected in parallel to the bus at which they feed power into the grid. This assumption is valid when neglecting the power losses, switching effects and time delays of the generator-side and the grid-side power converters, what is possible for frequency variations modelling, as stated before.

An overview of the VSC configuration, as implemented in PowerFactory, is shown in Figure 2-10. The VSC is represented by an ideal average model. The VSC is connected to the grid model through resistive and inductive elements. The VSC model synchronizes to the grid through a phase locked
loop (PLL) and operates with conventional decoupled PI current controllers. The latter regulates the terminal voltage of the ideal sources connected to the grid. The control scheme of the VSC average model was covered in MIGRATE D5.2 [24] and will not be described here. However, the coupling of wind turbine driven generators with the grid is clarified in the following.

The active and reactive power references of the wind farm, $P_{WF,ref}$ and $Q_{WF,ref}$, serve as the input signal for the power output of the VSC model. As mentioned before the PMSG and the AC grid can only exchange real power and not reactive power in normal operation. When neglecting the power losses, the active power reference $P_{WF,ref}$ is obtained by the summing the air-gap power of all PMSG units in a wind farm as follows:

$$P_{WF,ref} = \sum_{i=1}^{n} P_{e_i}$$  

(2.9)

where $n$ is the number of wind turbines in a wind farm and $P_{e_i}$ is the air-gap power of the $i$th wind turbine.

Wind farms connected at voltage levels of 110 kV or above employ voltage control at point of common coupling (PCC). The voltage control is achieved by implementing an AC voltage controller into the VSC control as shown in Figure 2-10. The AC voltage controller, described in [24], defines the reactive power output $Q_{WF,ref}$ of the VSC to support the grid voltage. The reactive power output $Q_{WF,ref}$ is set to zero for wind farms connected at voltage levels below 110 kV in the PowerFactory grid model.

![Figure 2-10: Overview of the configuration and control structure of the voltage sourced converter.](image-url)
2.4 Extended Power Command Synthesizer for Mitigation of Frequency Variations

The control design presented in 2.3.1 ensures WECS efficiency and stability. The design of integral and lead-lag elements compensates the power control loop for dynamic behavior. The power command synthesizer tracks the maximum power point (MPP) while maintaining WECS stability. However, the control design still needs to deal with the frequency variations, what will be covered in this section.

Since the active power fluctuations are the main cause of the frequency variations, the mitigation method is realized by modifying the active power control design of the generator side converter. More specifically, the power command synthesizer is extended to mitigate the frequency variations by utilizing the kinetic energy stored in the rotor of the WECS. In the case of under-frequency, kinetic energy is released to support the grid. For over-frequency, the WECS feeds less power into the grid and stores kinetic energy. The block diagram description of the generator-side model with the extended power command synthesizer for the mitigation of frequency variations is given in Figure 2-11. The additional input signal, \( \omega_{PLL} \), is fed from the phased locked loop of the grid-side converter model and corresponds to the grid angular frequency. To mitigate the frequency variations, the power reference \( P_{e,ref} \) of the original power command synthesizer, given in (2.5), is modified to include a frequency-supportive power signal \( \Delta P_{kin} \). The frequency-supportive power signal \( \Delta P_{kin} \) is determined based on the system frequency variations. The latter depends on the deviation of the grid angular frequency \( \omega_{PLL} \) from the nominal angular frequency of the grid. Accordingly, the power reference \( P_{e,ref} \) of the extended power command synthesizer for the mitigation of frequency variations is given as follows:

\[
P_{e,ref} = P_{MPP} + \Delta P_{kin}
\]  

(2.10)  

As the maximum power point \( P_{MPP} \) fluctuates with the available wind, the frequency-deviation-dependent signal \( \Delta P_{kin} \) tries to counteract the effect of \( P_{MPP} \) on the system frequency by smoothing the reference power signal \( P_{e,ref} \). With the power reference design of (2.10), the frequency variations around the nominal system frequency are mitigated through \( \Delta P_{kin} \) while proceeding with maximum power point tracking. However, the additional power signal \( \Delta P_{kin} \) causes the power reference to deviate slightly from the maximum power point. Such deviations from the maximum power point cause wider variations in turbine rotational speed and generator torque around the optimal operating point. If \( \Delta P_{kin} \) is selected positive, the WECS releases kinetic energy to support the grid and the rotor speed \( \omega_e \) decelerates. Respectively, the WECS stores kinetic energy to support the grid and the rotor speed \( \omega_e \) accelerates if \( \Delta P_{kin} \) is negative. This effect can be quantified and is implemented based on the equation of motion given by

\[
\frac{4}{p^2} \omega_e \frac{d\omega_e}{dt} = -\Delta P_{kin}
\]  

(2.11)
Nonetheless to ensure the stable operation of WECS, the magnitude of $\Delta P_{\text{kin}}$ has to consider the rotor speed limits. In the case of positive $\Delta P_{\text{kin}}$, a decreasing rotor speed $\omega_e$ will lead to a decreasing tip speed ratio $\lambda$ as given by the relation in (2.4). As the tip speed ratio decreases, the operating point may lie outside the preferred region of operation described in 2.3.1.2. In order to remain operating within the preferred region, the magnitude of $P_{e,\text{ref}}$ is adapted by reducing its value below $P_{\text{MPP}}$ when the tip speed ratio approaches the boundaries of the preferred region. When reducing the power reference $P_{e,\text{ref}}$ below $P_{\text{MPP}}$, $\Delta P_{\text{kin}}$ becomes positive and kinetic energy is captured. If $\Delta P_{\text{kin}}$ is positive, the rotor accelerates and the tip speed ratio is increased, as determined by equations (2.11) and (2.4).

Figure 2-11: Overview of WECS configuration with the extended power command synthesizer for the mitigation of frequency variations.

2.5 Grid Modeling

The grid model is a nonlinear dynamic system model based on the transmission system of Ireland shown in Figure 2-12. The grid model is provided by the Irish transmission system operator (TSO) EirGrid and implemented in the simulation software PowerFactory DIgSILENT. The grid model had been adjusted to the specifications of the future scenario in MIGRATE Deliverable D5.4 and is referred to as “2040 Baseline Model” [9]. The “2040 Baseline Model” contains 6840 nodes with voltage levels of 110 kV, 220 kV, and 400 kV. The grid element models comprise loads, synchronous generators, and non-synchronous power generation units. The non-synchronous power generation considered in the grid model are: onshore wind farms, offshore wind farms, wave and tidal power plants and battery storage units.

For representing the behavior of offshore and onshore wind farms, 1786 WECS model are integrated into the grid model considering individual wind speed profiles. The wind speed profiles are modelled as described in MIGRATE D5.3 [26]. The type of WECS model is assumed to be the same for all WECS units and represents a nonlinear model with a type 4 wind turbine that is described in Section 2.3.1. The wind turbines are grouped into 35 onshore wind farms and 4 offshore wind farms of different sizes. Onshore wind farms are connected at a voltage level of 38 kV or 110 kV, while offshore wind farms are connected at 220 kV. Each wind farm is interfaced into grid model by a voltage sourced converter (VSC) as explained in Section 2.3.2. The control scheme of the VSC is based on [2].
The modelling of loads, synchronous generators and non-synchronous power generation units that include battery storage units, wave-, and tidal-power plants was covered in MIGRATE Deliverable D5.4 [9].

![Irish Grid](image_url)

Figure 2-12: Irish Grid [27].

### 2.6 Validation Setup

The effect of PE penetration on frequency variations was studied in MIGRATE Deliverable D5.4 with the help of several study cases [9]. The PE penetration level was defined in alignment with MIGRATE WP1 as the system non-synchronous penetration (SNSP), expressed in percent [28].

\[
SNSP = \frac{P_{PE} + P_{DC,import}}{P_{load} + P_{loss} + P_{DC,export}} \cdot 100\% \quad (2.12)
\]

where, \(P_{PE}\) is the PE-interfaced generation and comprises the aggregated active power feed-in by wind farms, battery storage, wave and tidal power plants, and photovoltaic power plants. The total active power demand is represented by \(P_{load}\), while \(P_{DC,import}\) and \(P_{DC,export}\) stand for aggregated active power import and export to external grids via DC lines, respectively. The aggregated transmission power losses is signified by \(P_{loss}\).

In this section, the operating points of the validation setup are specified to enable studies for validation of the effectiveness of mitigating frequency variations. In the study case, the PowerFactory grid model, defined in the previous section, is assumed to be operating with an SNSP level of 90\%, thus offering a challenging context in terms of frequency variations. This is the highest level of SNSP
that was studied in MIGRATE Deliverable D5.4 [9]. The operating points of the 2040 Baseline Model with an SNSP level of 90% are defined in Table 2-1. The aggregated active power demand $P_{\text{load}}$ of 5.9 GW represents a winter peak situation. The power input $P_{\text{pv}}$ by photovoltaic power plants is set to zero since the winter peak demand in Ireland usually occurs after sunset [29]. The operating points of the aggregated active power feed-in by wind farms, $P_{\text{wind}}$, wave and tidal power plants, $P_{\text{ocean}}$, and battery storage units, $P_{\text{battery}}$, are set to 4549 MW, 40 MW, and 200 MW, respectively. The power exchange with external grids via DC lines $P_{\text{DCimport}}$ and $P_{\text{DCexport}}$ are set to 800 MW and 0 MW, respectively. The power infeed from synchronous machines, $P_{\text{SG}}$, is set to 621 MW and the installed capacity of synchronous generators in operation, $S_{\text{SG}}$, is 1466 MVA. The equivalent system inertia constant, $H_{eq}$, is calculated to be 1.03 s and the inverse of the equivalent governor speed droop, $1/R_{eq}$, is 677 MW/Hz.

For the simulations of the study case, all wind turbines within a wind farm are assumed in operation. The parameters of all WECS are similar and summarized in Table 2-2.

### Table 2-1: Operating points for test case of 90% SNSP level.

<table>
<thead>
<tr>
<th>SNSP [%]</th>
<th>$P_{\text{load}}$ [MW]</th>
<th>$P_{\text{losses}}$ [MW]</th>
<th>$P_{\text{pv}}$ [MW]</th>
<th>$P_{\text{ocean}}$ [MW]</th>
<th>$P_{\text{battery}}$ [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>90</td>
<td>5894</td>
<td>315</td>
<td>0</td>
<td>40</td>
<td>200</td>
</tr>
<tr>
<td>$P_{\text{DCimport}}$ [MW]</td>
<td>$P_{\text{DCexport}}$ [MW]</td>
<td>$P_{\text{wind}}$ [MW]</td>
<td>$P_{\text{SG}}$ [MW]</td>
<td>$S_{\text{SG}}$ [MVA]</td>
<td>$H_{eq}$ [s]</td>
</tr>
<tr>
<td>800</td>
<td>0</td>
<td>4549</td>
<td>621</td>
<td>1466</td>
<td>1.03</td>
</tr>
</tbody>
</table>

### Table 2-2: WECS parameters.

<table>
<thead>
<tr>
<th>Wind Turbine and PMSG Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated power $P_{\text{tur}} = 3$ MW</td>
</tr>
<tr>
<td>Rated rotor speed $n = 18$ rpm</td>
</tr>
<tr>
<td>Rated wind speed $V_{\text{n}} = 12$ m/s</td>
</tr>
<tr>
<td>Maximum power coefficient $C_P(\lambda_{\text{opt}}) = 0.445$</td>
</tr>
<tr>
<td>$r = 45$ m</td>
</tr>
<tr>
<td>$\rho = 1.255$ kg/m$^3$</td>
</tr>
<tr>
<td>$\lambda_{\text{opt}} = 7$</td>
</tr>
<tr>
<td>$J = 8.44 \times 10^6$ kg/m$^2$</td>
</tr>
<tr>
<td>$D = 0$ N.m/(rad/s)</td>
</tr>
<tr>
<td>$p = 160$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Current and Power Control Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\tau_i = 2$ ms</td>
</tr>
<tr>
<td>$\tau_{\omega} = 11.4$ s</td>
</tr>
<tr>
<td>$\tau_z = 80$ s</td>
</tr>
<tr>
<td>$K = 10$</td>
</tr>
</tbody>
</table>

### 2.7 Results

In this section, the results of the simulations are presented for the study case based on the validation setup described in the previous Section 2.6. The performance of the proposed method for the mitigation of frequency variations is assessed by comparing the simulation results of two scenarios.

In the first scenario, all wind turbines within a wind farm are assumed to operate in maximum power point tracking (MPPT) mode. For this scenario, the power output of the WECS is maximised based on the incoming wind by employing power command synthesizer which is described in Section 2.3.1.3.
The results with MPPT operation are expected to describe a situation with high frequency variations caused by wind farms since the WECS are not participating in the mitigation of the frequency variations.

In the second scenario, the proposed method for the mitigation of frequency variations is implemented by replacing the power command synthesizer with the extended power command synthesizer in Section 2.4. This will allow the WECS to mitigate the frequency variations. In the results, MPPT operation stands for the first scenario while proposed method refers to the second scenario.

In the following, the focus of the analysis is set on frequency and active power variations as indicators for the performance of the developed proposed method for the mitigation of frequency variations. For ease of comparison, simulation figures of the two scenarios are presented side by side.

**Frequency**

Figure 2-13 and Figure 2-14 show the system frequency in case of an MPPT operation and the proposed method for the mitigation of frequency variations, respectively. The frequency is measured by a phase locked loop at the point of common coupling of a grid connected WECS. In case of only MPPT operation without the proposed method, the frequency deviations are comparatively large and almost approach the frequency operation limits of ± 0.2 Hz. The frequency deviations are to be expected since the grid is operating with an SNSP level of 90% and the real power produced by the WECS model is allowed to fluctuate with the available wind. In case of further potential disturbances, it might be difficult to keep the system frequency within the admissible limits. Thanks to the proposed method for the mitigation of frequency variations, the frequency variations are damped significantly as seen in Figure 2-14. The maximum and minimum frequency deviations from the nominal are reduced by almost 70%.

The frequency distribution with a normalised histogram as well as the empirical distribution function of the frequency values are presented in Figure 2-15 and Figure 2-16. The distribution reveals a standard deviation $\sigma$ of 46.2 mHz in MPPT operation and 15.4 mHz in the proposed method for the mitigation of frequency variations. This corresponds to a 66.67% reduction in the standard deviation.
Active power

Figure 2-17 and Figure 2-18 illustrates the aggregated active power feed-in of wind farms. The proposed method for the mitigation of frequency variations causes the delivered active power by the wind farms to become much smoother as shown in Figure 2-18. This happens because the fluctuating feed-in of active power by wind farms is the primary cause of the frequency variations. The average active power over the 10-min horizon in Figure 2-17 and Figure 2-18 is 4584.94 MW and 4584.49 MW respectively. On that account, the average active power is 0.01 % less when employing the proposed method for the mitigation of frequency variations as to when operating in MPPT only. Although there is slight reduction in the energy extraction efficiency, the use of the proposed method for the mitigation of frequency variations dampened the frequency variations significantly.
2.8 Conclusions

A method to mitigate power system frequency variations by controlling the output power of wind energy conversion system (WECS) was developed. The proposed method addressed the frequency variations arising from the high shares of power electronic interfaced generation, particularly wind power plants. Through the utilisation of the kinetic energy stored in the rotating mass of WECS, the proposed method allowed the WECS to release kinetic energy during under-frequency and store kinetic energy during over-frequency. The mitigation method does not require any additional hardware, as it is implemented by slight modification of the WECS control. Furthermore, supplementary control loops for frequency support, such as inertial control loop, can be operated in conjunction with the proposed method.

The proposed method for the mitigation of frequency variations was validated on a model based on the Irish transmission system which was adapted according to a future energy scenario of 2040. For representing the behavior of offshore and onshore wind farms, 1786 WECS model were implemented considering individual wind speed profiles. The performance of the proposed method in mitigating the frequency variations was assessed through comparison with the MPPT operation. It was shown that the proposed method had significantly mitigated the frequency variations, with minimal power losses. Those power losses are caused by the slight deviation from the maximum power point. Moreover, the proposed method for the mitigation of frequency variations significantly smoothened the active power feed-in of wind farms. This implies that less balancing energy is needed to keep the power balance in the system. Consequently, the balancing energy from primary control participation of the fossil fuel power plants is expected to decrease.
3 Device Based Mitigation of Harmonic Emissions

3.1 Motivation

Nowadays, the share of wind, PV generation and other distributed energy sources is increasing, the high-voltage DC current transmission is becoming an increasingly viable alternative for power transmission over large distances and in order to achieve stable and reliable operation of the power system under fluctuating energy generation, compensation devices, such as StatCom or Static VAR Compensator, are becoming an inevitable part of the modern power systems. All his devices are connected to the network with power electronic interfaces (AC/DC converters) that may worsen the power quality levels in transmission system.

To limit the adverse effects of the PE-based devices on the power quality, regulators have developed strict rules and requirements for the operation of such devices and defined rigorous limits for the allowable influence on the power quality. Among others, allowable influence on the harmonic distortion that is also one of the power quality parameters is strictly defined.

The harmonic contributions (emissions) of several PE-devices have been thoroughly investigated and reported in Deliverable D5.2 of the MIGRATE project [24]. As it has been shown in the deliverable, the operation of PE-devices and their emissions depends on the topology and control algorithms. Controllers define overall dynamics of the device including response to changes of the operating points or to distortions of any kind. Proper design and tuning of controllers is the main challenge of the developers of the PE based devices, and the strict rules for the operation increase the complexity of the designs [24].

To address the challenges, in this section, different device-based harmonic mitigation solutions will be investigated, using EMT simulation models of PE-devices that have been developed within D5.2. Based on the level of estimated emerging PQ issues and by using the numerical simulation, device-based mitigating solutions will be proposed.

3.2 Literature Review

Modern compensation devices play a key role in providing adequate parameters of power quality. In this section, an overview of the literature on passive and active harmonic filtering approaches is presented, which will form the basis for later derivations of mitigation techniques with individual PE-devices.

3.2.1 Passive Filters

The most-often solution for harmonic filtering in power system is conventional filtering device. Because of the passive elements that consist these filters ($R$, $L$, and $C$), we also call them passive filters. Before installing such a device in the power system, it is important to carry out a thorough
analysis of the impact that the device will have on the network. Namely, even though filters do not
generate harmonics, they can greatly affect the level of harmonic distortion in the system. Each
network containing capacitance and inductance has one or more natural frequencies, and when one
of these frequencies is matched by a harmonic, present in the network, the harmonic components
of current and voltage can be strongly (resonantly) amplified. The main disadvantage of these filters
is therefore the danger of resonance between the filter and the network, which can be particularly
problematic for larger devices.

This is more or less successfully prevented by the correct selection of the filter elements (by tuning
it), but nevertheless we can only speak of a reduced probability of the onset of resonance and not
of complete elimination. The positive features of these devices are their robustness, high power
levels (few MVAR), and almost maintenance-free operation. In addition to the aforementioned
resonance between the compensator and the network, their inflexibility and physical size are also
cited as weaknesses in the literature [33-35]. Passive compensators achieve the highest electrical
dimensions when used with HVDC systems [36].

Figure 3-1 shows the most basic implementations of passive filters, which form the basis for deriving
designs that are more complex. Any combination of passive elements (R, L and C) when used in the
frequency space is called a passive filter. In power engineering, filters are used primarily in the field
of filtering harmonic current components. They are divided according to how they behave in the
frequency space:

- low-pass filter,
- high-pass filter,
- band-pass filter.

According to the principle of operation of passive filters in the field of power electrical engineering,
we distinguish between series and parallel filter. Series filters are not very often in practical
applications due to higher losses. The parallel filters are tuned to represent a sink (low impedance)
for certain harmonics. They are usually composed of several units, with each of them tuned to a
specific harmonic. They are installed close to the sources of harmonic currents, thus preventing their
flow through the network and the associated adverse effects [37].

![Figure 3-1: Basic variations of passive filters.](image-url)
3.2.2 Active Filtering Techniques

With the development of semiconductor switches, active filters (AcF, or active compensators or static compensators - StatComs) are becoming increasingly important as switching losses of inverters are becoming smaller and the designs of increasing rated power are available [38, 39]. A very simplified scheme of the active filter is shown in Figure 3-2. With the proper implementation of the power converter control algorithm, active filters are able to cope with numerous tasks in the field of electricity quality provision. Of course, better performance also requires a higher price, and this is a key reason that there is still a dilemma in deciding whether to use a passive or active filter [40].

The central part of these devices is a power converter (voltage or current), which is controlled so that the device improves the selected parameters of power quality. Today, the most problematic parameters are in particular power outages, voltage fluctuations, flicker, harmonics, voltage asymmetry – which can be effectively limited by active filters.

In addition, active filters are also used to filter harmonics, with a distinct advantage over passive filters in that they do not cause resonance with the system. They also have the capability to operate independently of the impedance characteristic of the system, so they can be used in demanding conditions where the use of passive filters is not possible due to the resonance problem. The active compensator can, in contrast to passive, track changes in the filtered harmonic flow of the selected nonlinear load. They operate by constantly monitoring the harmonic content in voltage and / or current and injecting the corresponding currents, with the amplitude equal to the filtered currents, but phase shifted so that filtering is obtained.

The main disadvantages of active filters are [41]:

1. the construction of large and fast power converters is very demanding,
2. the investment and operating costs of active filters are high.

Figure 3-2: Active filter.
The AcF can be operated in such a way that it operates as (more than one) passive filter, in other words it mimics operation of passive filters, without negative effects between the filter and the network. Besides harmonics compensation, these compensators can be used to compensate for reactive power, where the active element generates a capacitive fundamental frequency current such that the network current has a power factor close to one [42]. Often the two functions, the compensation of the base component of the reactive current and the filtering of harmonics, are combined in one device. Such compensators are used quite frequently, and several commercial installations are also available [43, 44].

Because typically the electrical dimensions of these compensators are quite large, topologies composed of several converter units appear in the literature [45-48]. By putting several smaller units together, the required large dimensions and wide filter ranges are achieved.

3.2.2.1 Basic Control Algorithms Principles

Many different algorithms for controlling active filters for reactive power compensation and/or harmonic filtering have been discussed in the literature, and most algorithms operate in a similar manner. Namely, the influence of active filters on a network can be illustrated by the proper equivalent diagram of passive elements, whereby the parameters of the circuit elements are dynamically adjustable according to the conditions in the network [49]. They operate on the principle of frequency selectivity. Some basic operating modes are presented below.

Also, control algorithms can be divided into narrowband and broadband. Broadband algorithms operate over a wider frequency range and typically filter multiple harmonics simultaneously, while narrowband regulators operate at individual harmonic frequencies. In the past, authors have mainly studied broadband algorithms, but with the development it has emerged that in some configurations the stability between transient phenomena in these regulators is not satisfactory [50]. In recent years, therefore, there has been a particular focus on narrowband regulators, which will also be used in this work.

3.2.2.1.1 Resistance Mimicking

Often, active filters are used only to suppress the resonant states between the passive compensator and the network [51-55]. Passive compensators intended for filtering harmonics are often designed with a high quality factor Q. With such filters, harmful interaction with the network is of even greater risk since, due to a lack of damping, parallel resonance with the network can result in very high impedance values. To prevent dangerous resonances, an active compensator is used (added to the passive compensator), which acts as an ohmic resistor at harmonic frequencies. The active filter thus does not cause additional losses of electricity at the fundamental frequency that would the use of an actual damping resistor. It is a broadband controller as it operates over a wider frequency range. The inverter generates a voltage that is proportional to the network harmonic current and is therefore basically a proportional feedback controller.
In Figure 3-3 (a), this mode of operation is shown schematically. A passive filter typically consists of several tuned units with a high quality factor to achieve good filter properties. The active part acts as an ohm impedance at harmonic frequencies for the mains current, thus increasing the total impedance of the network, further converting the load harmonic currents into the filter. Equivalent resistance simultaneously suppresses the resonant states between the compensator and the network. At the fundamental frequency, the active part represents a short circuit and therefore does not affect the basic component.

3.2.2.1.2 Inductance Mimicking

When the passive filter is not correctly tuned or detuned by the change in the topology or parameters of the network elements, an active filter can be used that is connected in series with the passive part, as shown in Figure 3-3 (b). The active part operates in such a way that it represents the inductance (positive or negative) at a certain harmonic frequency. In such operation, the control algorithm determines the appropriate inductance value for the filter to effectively filter a particular harmonic. This mode of operation is shown schematically in Figure 3-3 (b). The active part thus increases or decreases the existing coupling inductance to achieve the best filtering. Since such a regulator only works for a specific harmonic, it is considered to be a narrowband regulator.

3.2.2.1.3 Capacity Mimicking

Capacitance is equivalent to negative inductance when viewed at a given frequency. In the previous section, we described control algorithms that mimic positive or negative inductance. The case where the controller operates as negative inductance is equal to mimicking the capacitance at a given frequency. Explicit capacitance mimicking usually occurs with series compensation devices [56].
3.2.2.1.4 Other Control Algorithms

Some regulators can emulate more than one passive element. An example is a parallel passive filter, which is simultaneously used to compensate for the basic reactive power component and to filter harmonics. Such a compensator operates as a capacitor at fundamental frequency (for reactive power compensation) and as a high-pass passive filter for filtering harmonics. Higher-order feedback controllers (PI and PD) can also be presented with an equivalent passive structure. A PI-controlled broadband filter is presented in [50]. Author shows that the proportional constant of the controller is equivalent to the additional network inductance, and the integral constant represents the additional network resistance at harmonic frequencies. Similarly, we can represent other more complex higher order regulators.

3.2.2.2 Conventional PI Regulator

The most widely and commonly used controller in many applications where the reference does not change over time (dc value) or these changes are relatively slow is the proportional-integral (PI) controller. To use this controller for ac signals, such as phase currents on the ac side of the inverter, requires some other signal adjustments. Alternating signals can be converted to dc signals using e.g. Park Transform. Thus, PI regulators can also control alternating signals without error, but two controllers are required, separately for the d and q components. Various ways of implementing PI regulators in the Park space can be found in the literature. The most common approach will be presented below.
The conventional PI controller provides a transfer function:

\[ H_{PI}(s) = k_p + \frac{k_i}{s}, \]  

(3.1)

where \( k_p \) and \( k_i \) are the proportional and integral constants of the controller. The controller given by the equation above, when used in power engineering, where the signals are mostly alternating, is typically implemented in a dq-coordinate system. In order to properly separate the individual harmonic components by filtering, the dq-coordinate system must be synchronized to the harmonic frequency \( h \times \omega_1 \), with \( h \) being the harmonic order. By selecting the appropriate \( k_{ph} \) and \( k_{ih} \) constants, the controller can be applied to several individual harmonics \( h \).

\[ H_{PH}(s) = k_{ph} + \frac{k_{ih}}{s}, \]  

(3.2)

The schematic of the PI controller in the dq-coordinate system is shown in Figure 3-4, where the ref indices indicate that these are the reference values of the variables. The angular velocity \( h \times \omega_1 \) is determined by synchronization with the angular system voltage velocity.

![Figure 3-4: Single line diagram of a PI controller.](image)

3.3 General Approaches of Harmonic Mitigation in Wind Turbines and Farms

There are primarily two methods utilised for the mitigation of harmonics: the first one is to use auxiliary devices, and the second one is to reduce the harmonic injection from the main power sources [57]. Since it has been recognized that the PE devices are the main source of harmonic distortions, the robust design of electronic interfaced convertors is one of the most effective methods to reduce harmonic injections contributed by DGs. In what follows, these mitigation methods are discussed further.

3.3.1 Active damping of Harmonics in Wind Turbines

3.3.1.1 Typical Designs of Wind Turbines

There are four main types of wind turbines (WTs) in the present wind power industry [58], namely fixed speed induction generator, wound rotor induction generator, double-fed induction generator
(DFIG) and full converter connected (FCC) generator. These four types of wind turbine are shown in Figure 3-5 (a-d). As can be seen from Figure 3-5, in the case of the fixed speed induction generator and the wound rotor induction generator, the induction generator is directly coupled to the main grid, and the operation of WTs is significantly limited by system frequency. While in the design of the DFIG and the FCC, a back-to-back converter is installed next to the induction generator so that it can be decoupled from the main grid, enabling variable speed operation of the wind turbines, thus allowing maximum power output while maintaining low stress on the system. The converter coupling allows the generators to both absorb and deliver power to the grid. The disadvantage of DFIG and FCC generators is that they do not provide inertia for the system because the PE configuration makes the rotors electrically decoupled from the grid. However, by implementing additional control mechanisms, similar responses can be emulated.

The fixed speed induction generator and wound rotor induction generator are more traditional designs and may provide some inertia. Capacitors are commonly used to maintain voltage. However, without the controllability offered by power electronics, these two types of generator become inferior to other types.

Compared with FCC generators, the relatively low rating requirements (25-30% of generator rating) make the DFIG a more economical and competitive choice in modern power systems. FCC generators can further improve the operational flexibility of the WTs since the full-scale converters completely decouple the induction generators from the main grid. However, since the converter must be fully
rated to the turbine power output, it is quite expensive. The following discussions mainly concentrate on harmonic mitigation methodologies applied in the case of DFIG and FCC generators, as prevalent in modern power networks.

3.3.1.2 Active Damping of Harmonics in DFIG Wind Turbine

Generally, the converter closest to the grid is named as the Grid Side Converter (GSC), while the converter closest to the generator is called the Rotor Side Converter (RSC). The main function of the GSC is to supply a stable/constant DC voltage to the RSC such that the RSC can properly adjust the active power and reactive power injected into the main grid from the induction generator [59]. In order to reduce the total harmonic distortion (THD) at the Point of Common Coupling (PCC), a novel control algorithm, which enables a Wind Energy Conversion System (WECS) to partially operate as an active Filter, is proposed in [60]. The control is defined in an equivalent reference frame obtained by applying the Park Transformation to the three-phase quantities. The zero-sequence component is included in the control system. This feature enables the compensation of zero-sequence harmonics.

The basic idea is to generate harmonic current from the GSC with the same magnitude but opposite phase angle as that generated by the other harmonic sources at the PCC. The proposed harmonic mitigation solution has been validated by simulation of a test system with high THD and the results are summarised in Table 3-1. It can be seen that the main advantage of GSC compensation is the significant improvement of both voltage and current THD measured at the PCC. However, the proposed control scheme could also result in some operational issues. For example, the injection of harmonic currents from the GSC enlarges the power losses of DFIG windings and converters, which requires DFIG de-rating and increases the operation cost of wind turbines. Moreover, the harmonic currents generated by the GSC can lead to the voltage distortion of DFIG windings, as well as the increase of peak voltage across the DFIG stator and rotor [60].

Table 3-1: Voltage and current distortion without/with GSC modulation [60].

<table>
<thead>
<tr>
<th>Quantities</th>
<th>THD (%) without Modulation</th>
<th>THD (%) with Modulation</th>
<th>Percentage Reduction (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage</td>
<td>25</td>
<td>7.5</td>
<td>70</td>
</tr>
<tr>
<td>Current</td>
<td>11</td>
<td>5.5</td>
<td>50</td>
</tr>
</tbody>
</table>

For the purpose of reducing the power loss of DFIG windings and the harmonic distortions at the PCC, the control algorithm of the GSC is improved in [61], so that the GSC can operate as an active filter. Similar to [60], the harmonic currents injected by the other harmonic sources at the PCC are adopted as the current reference, based on which the GSC generates compensation current following the triangular carrier methods [61]. Through case studies, the current THD at the PCC can be reduced by 7.54% (from 9.27% to 1.73%). The proposed control scheme can also reduce the computational cost of the controller, thus making the algorithm much simpler. In addition, with the new developed control scheme, the copper and iron losses of DFIG can be reduced.
The main disadvantage of the mitigation solutions mentioned above is that the whole algorithm requires measurements of load voltage and current at the PCC in order to generate the corresponding compensation current in the GSC, which results in complex and high computational costs. Additionally, the active filter can only mitigate the overall harmonic distortion but has very limited ability to mitigate harmonic distortion of a certain order or a certain frequency.

Consequently, in order to improve the performance and efficiency of the GSC, the coordination between active filter and harmonic insulator is studied in [62]. In this new algorithm, the harmonic insulator only measures the load current at the PCC and the harmonic current of a specific order can be blocked in a selective filtering scheme. The harmonic current of one (or more) orders is realized as the reference current of the active filter to mitigate harmonic distortion at the order(s). The updated active filter control method can reduce the current THD at the PCC from 13.23% to less than 4% with full harmonic compensation (mitigation of harmonic distortion at all harmonic orders). When the selective filter is set to extract only the 5th and 7th harmonic orders, it can be observed that the current THD measured at the PCC decreases by 7.73% (from 13.23% to 5.5%). Furthermore, the impacts of harmonic pollution on the effectiveness of the proposed GSC is discussed as well. With the increasing of harmonic pollution at the PCC, the original current THD (without any modulation) at the PCC varies from 8.07% to 13.23%, in the meantime, the current THD at the PCC after full harmonic compensation varies from 3.22% to 3.95%. After the deployment of the selective filter, the current THD at the PCC varies from 4.18% to 5.5% [62].

The primary advantage of updated control strategy for WECS with a GSC based active filtering capacity and harmonic insulator is that it reduces the measurement burden and improves the ability of harmonic mitigation for certain orders and frequencies. However, the deployment of harmonic insulators requires more electronic components, which increase the investment of WECS.

Likewise, the authors of [63] redesigned the GSC controller. Based on the robust design of both inner-loop control and outer-loop control, the current THD at the PCC has been significantly improved in a simulation environment (from 27.56% to 3.65%). In order to prove the feasibility of the proposed methodology in a practical application, a small-scale DFIG system rated at 2kW with the same modelling and control parameters as in the simulation environment, is built and tested. In the actual test system, the current THD at the PCC decreases from 27.9% to 17.2%. The difference between the results obtained from the simulation environment and the real-world experiment is mainly due to the deviation of sensors, switches and measurement devices. Moreover, the experiment results are also highly affected by the physical limitations regarding hardware implementation, the slow response of devices and the software looping time [63]. The main disadvantage of this design is the variable switching frequency, which may deteriorate the benefits of the design in harmonic mitigation.

Other optimization approaches could also be implemented to achieve harmonic mitigation. The Bacterial Foraging Optimization Algorithm (BFOA), which has been widely adopted for global
optimization, is utilized in [64] to improve system power quality. The development of the BFOA is inspired by the foraging behaviour of bacteria. It has been shown in [64] that the implementation of the BFOA can improve system power quality by reducing the THD of the PCC through optimizing the proportional and integral gains of the WECS controller.

In summary, in the case of the DFIG, in order to reduce harmonics, the improvement and new design of electronic interfaced converters in WECS mainly focus on the GSC. Its function is not only to provide constant DC voltage to the RSC, but also to support system operation through several ancillary services. For example, the reactive power compensation can improve the fault ride-through ability of wind turbines, while the active filtering capacity can mitigate harmonic distortion at the PCC [65]. Even though the operation of the GSC as an active filter cannot reduce the harmonic injection contributed by WTs, the compensation current generated by the GSC is able to cancel the harmonic current injected by the other harmonic sources (typically non-linear loads), thus improving the harmonic performance at the PCC.

3.3.1.3 Active Damping of Harmonics in FCC Wind Turbine

Since the operation of wind turbines with the FCC requires the converters to operate in full capacity, the cost of converters implied in this type of wind turbine is much more expensive than that in the DFIG design. Therefore, the FCC type of wind turbine is less attractive and has not been as widely applied in modern wind industries, even though it provides more operational flexibility than the other types of WT. However, with the rapid development of technology, the price of electronic components has been reducing in recent years, which makes it possible for FCC wind turbines to become the mainstream choice in the future.

Two mitigation solutions are proposed in [66] regarding the improvement of electronic interfaced converters. In the first solution, as shown in Figure 3-6, it is recommended to use a single-switch three-phase boost rectifier instead of a conventional three-phase RSC (AC-DC converter), because it generates less harmonic current and results in lower THD value. In addition, due to its simple structure, the proposed single-switch three-phase boost rectifier is easier to control and consumes lower construction costs. However, the implementation of the proposed rectifier could increase the power losses in the RSC and additional input capacitors are required for its normal operation.

In terms of the second solution, the three-phase boost type Pulse Width Modulation (PWM) rectifier, as depicted in Figure 3-7, is proposed to overcome the shortcomings of single-switch three-phase boost rectifier owing to its low harmonic injection at all operation points [66]. Nevertheless, the requirement for more active components increases the cost and complexity of the corresponding control scheme. It has been illustrated in [66] that these two recommended RSC designs can reduce the harmonic current feeding in to the grid system.
Figure 3-6: Single-switch three-phase boost rectifier applied in WECS [66].

In [67], a single-switch three-phase boost rectifier is proposed and studied to replace the traditional rectifier. Moreover, an improved Maximum Power Point Tracking (MPPT) is developed to control the switch in a single-switch three-phase boost rectifier to simultaneously achieve both maximum power tracking and harmonic mitigation. By applying such modified control strategy, the current THD value at the PCC is reduced from 11% to 2.57%. Since the operation of the proposed MPPT rectifier does not depend on anemometers or mechanical sensors, the construction of the rectifier is cheaper, and its implementation is much simpler. The function of harmonic mitigation is controlled by the MPPT. Consequently, the efficiency of such a mitigation solution is easily affected by the wind speed profile, which is considered to be the main disadvantage of the proposed control algorithm.

Figure 3-7: Three-phase boost PWM rectifier applied in WECS [66].

A simple and robust fuzzy logic with the application of Adaptive linear Neuron (Adaline) controller is adopted in [68] to mitigate harmonics in the FCC to supply power to the main grid. To be more specific, the fuzzy logic control is applied in the RSC to maintain constant DC voltage while the Adaline controller is applied in the GSC to provide both reactive power compensation and harmonic current cancellation. The simulation results in MATLAB verify the feasibility of the proposed control algorithm. When the grid is assumed to be ideal (no harmonic distortion in the main grid), the THD value at the PCC drops from 2.03% to 0.07% by implementing this control strategy. When the external main grid is assumed to be non-ideal, the control strategy brings about a 3.16% reduction (from 7.03% to 3.87%) of the THD value at the PCC [68].
More recently, a harmonic mitigation method covering both harmonic instability and resonance has been developed in [69]. In the optimization design process, the induction generator is considered as a multi-input multi-output (MIMO) model in frequency domain, such that the resonance frequencies can be obtained easily. According to the matrix based mathematical calculation, the redesigned GSC parameters can reduce the number of resonances while ensuring harmonic stability. The result shows that the optimized controller parameters reduce current THD and voltage THD from 4.87% and 7.23% to 0.87% and 1.02% respectively under the resonant condition [69].

From the above discussion, it can be seen that the improvement of the electronic interfaced converters based on the FCC wind turbine can be conducted in both grid side and rotor side. In order to mitigate harmonic distortion in power systems, a robust design of rectifier (single-switch three-phase boost rectifier and three-phase boost PWM rectifier) and an enhanced control algorithm (fuzzy logic) are proposed. In addition to updating and improving the operational profiles of power converters, the installation of filters alongside wind turbines or at the point of WF connection can also be considered as one of the most effective ways to improve harmonic problems and subsequently improve the overall power quality.

3.3.2 Harmonic Mitigation by Reconfiguration of Wind Farm

The configuration/layout of wind farms refer to how individual wind turbines are inter-connected in a wind farm and how power is collected by the power collector. In terms of different wind farm configurations, the total power output, power losses and harmonic generation of WFs change significantly. Furthermore, different configurations also influence the equivalent impedance seen from the PCC and the resonant frequencies of the WF. Therefore, wind farm reconfiguration could be an effective way to mitigate harmonic distortion.

The most commonly used wind farm configurations are the parallel (radial) configuration, the star (starburst) configuration and the T (central) configuration [70], shown in Figure 3-8 (a-c) respectively. The parallel configuration is comprised of several strings of WTs connected to the PCC bus. The T configuration collects power from all WTs together and transmits it to the collector bus. In the star configuration, each single turbine is linked with a central turbine and connected to the collector bus.
Harmonic distortion assessments of different WF configurations are performed in [70], where the skin effects of cables and transformers, and the wake effect of wind turbines are considered and modelled. In order to implement probabilistic approach, it is assumed that the outputs of WTs follow Weibull distribution, and the harmonic injections of each WT are generated randomly within a predefined range. The simulation results show that the star configuration results in the lowest THD at the PCC bus compared with the other two configurations. The parallel and T configurations are more economical and easier to control. However, when a fault occurs at an upstream WT, the whole string would be out of service, making it unreliable. The star configuration is more reliable at transmitting power but is more costly given the extra length of cables and switchgears. Therefore, there is a trade-off between capital investment in WF design and the potential cost of power quality mitigation.

As an extension of the studies conducted in [70], researchers in [71] investigated not only the harmonic distortion at the PCC bus, but also the resonance frequency of the entire wind farm. The voltage THD values of different WF configurations and different short-circuit fault levels of the external grid are shown in Figure 3-9. When the short-circuit fault level is higher than 1300 MVA,
the THD values of the PCC bus will decrease with the increase of short-circuit fault levels. When the short-circuit fault level is around 1300 MVA to 2000 MVA, the parallel configuration of WF results in the highest harmonic distortion among the three configurations, while the star and T configurations have very similar THD values at the PCC bus. When the short-circuit fault level increases to above 2200 MVA, the T configuration results in higher THD values at the PCC bus, which indicates the worst harmonic distortion. Therefore, the effect of different WF configurations on harmonic mitigation depends on the electrical strength of the external grid.

![THD curves with different short-circuit fault levels of different configurations](image)

Figure 3-9: THD curves with different short-circuit fault levels of different configurations [71].

Moreover, it can be noticed that when the short-circuit fault level is lower than 1300 MVA, some ripples, or peaks appear in THD curves, which is the consequence of resonance. Harmonic resonance occurs at different short-circuit fault levels with different WF configurations. Table 3-2 summarises the short-circuit fault levels when resonance occurs, the corresponding resonant harmonic orders and the THD values at the PCC bus.

The wind farm reconfiguration can decrease the THD at the PCC bus within certain short-circuit fault levels and move the resonance point to avoid a high THD. So this method can be considered as an effective solution to change or mitigate harmonic distortion at the PCC bus, however these effects are affected by the electrical strength of the external grid, which is usually quantified by short-circuit fault levels. Additionally, since the wind farm reconfiguration changes the equivalent impedance of the entire wind farm, resonance may occur in different situations. Therefore, the reconfiguration of the WF for harmonic mitigation should be implemented carefully with the consideration of the harmonic resonant point, short-circuit fault levels of external grid and the capital cost of the wind farm. This of course, should be considered at the design stage of the WF rather than a solution to be adopted once the WF is commissioned.
Table 3-2: Short-circuit fault level, THD and resonant harmonic order [71].

<table>
<thead>
<tr>
<th>Configuration</th>
<th>Short-Circuit Fault Level</th>
<th>Resonant Harmonic Order</th>
<th>THD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parallel</td>
<td>400 MVA</td>
<td>17</td>
<td>2.11%</td>
</tr>
<tr>
<td></td>
<td>1300 MVA</td>
<td>19</td>
<td>1.48%</td>
</tr>
<tr>
<td>Star</td>
<td>300 MVA</td>
<td>17</td>
<td>2.27%</td>
</tr>
<tr>
<td></td>
<td>1000 MVA</td>
<td>19</td>
<td>1.66%</td>
</tr>
<tr>
<td>T</td>
<td>120 MVA</td>
<td>19</td>
<td>3.34%</td>
</tr>
<tr>
<td></td>
<td>1000 MVA</td>
<td>23</td>
<td>1.37%</td>
</tr>
</tbody>
</table>

3.3.3 Harmonic Mitigation by the Converter’s Output Filter

By applying the Fast Fourier Transform (FFT) theory, a distorted sinusoidal waveform can be segmented into several ideal sinusoidal waveforms of different frequency. Therefore, the electronic filters are widely applied in modern power systems to improve power quality through eliminating signals with undesired frequencies and thus improving the shape of the aggregated sinusoidal waveform.

Filters are designed to select a frequency or frequency range out of a mix of various frequencies. According to the functionality of the different filters, they can be divided into four categories, namely low-pass, high-pass, band-pass and notch filters. As the name implies, the low-pass filter can prevent the propagation of signals with frequencies higher than a pre-defined value, while the high-pass filter can cut off the propagation of signals with frequencies lower than a certain value. For the band-pass filter, only signals within a certain range of frequency are allowed to pass through. The notch filter is mainly utilized to exclude signals within a certain range of frequency from the original infeed signals.

Eliminating such waveforms with harmonic frequencies contributes to harmonic mitigation and the improvement of the overall system power quality. Harmonic distortion is harmful for power systems because it can lead to a significant increase in voltage/current peak values and Root Mean Squared (RMS) values, resulting in an increase in dielectric and insulation stress (due to peak values) and power losses (due to RMS values). Therefore, harmonic filters are usually installed next to, or very close to, the harmonic sources to minimize the detrimental effect of harmonic distortion. As far as the wind turbines are concerned, since the harmonic distortion is mainly generated by the periodic switching of semiconductor switches within WECS converters, the harmonic filters are usually applied alongside the WECS or at the point of connection of a wind farm.

In [72], a Variable Frequency Active Power Filter (VF-APF) is applied in an FCC type of wind turbine to improve harmonic current mitigation and extend the induction generator life span. It consists of
a conventional fixed frequency three-phase shunt Active Power Filter (APF) and a Phase Lock Loop (PLL). The system configuration is shown in Figure 3-10.

![Figure 3-10: FCC based wind turbine system with VF-APF configuration [72].](image)

In the proposed system, the mitigation of harmonic current is achieved by an APF installed next to the rectifier (RSC) based on the Zero Average Current Error (ZACE) theory [73]. The APF produces a compensation current according to the current signal calculated by the ZACE, and the normal operation of the APF under different wind speeds/frequencies is achieved by using the PLL. In order to test the performance of this filter system, a 20 kW FCC based wind turbine (36 poles) system and a 10 kHz switching frequency APF are built in the PSIM® environment [72]. Table 3-3 summarises the current THD values in the induction generator at different wind speeds, from which it can be seen that the proposed VF-APF in quite effective in harmonic mitigation.

Likewise, a new modulation technique is proposed in [74] to reduce the harmonic distortion in the output current of the WECS. The modified modulation is applied to shunt the APF in the WECS based on Variable Index PWM (VIPWM). It has been tested together with the conventional modulation technique (i.e., sinusoidal PWM) in an FCC based wind turbine system rated at 20 kW. The THD of the WECS output current decreases from 11.42% to 2.84% and from 11.42% to 1.86% in the case of sinusoidal PWM and proposed VIPWM, respectively [74]. Thus, the superior performance of this shunt APF and modulation technique is proved.

Table 3-3: Current THD values in induction generator without/with VF-APF at different wind speeds [72].

<table>
<thead>
<tr>
<th>Wind Speed</th>
<th>THD without VF-APF</th>
<th>THD with VF-APF</th>
</tr>
</thead>
<tbody>
<tr>
<td>5 m/s</td>
<td>35.5%</td>
<td>4.9%</td>
</tr>
<tr>
<td>8 m/s</td>
<td>21.0%</td>
<td>0.6%</td>
</tr>
<tr>
<td>11 m/s</td>
<td>16.0%</td>
<td>1.6%</td>
</tr>
</tbody>
</table>
In addition to the APF, the implementation of the Passive Power Filter (PPF) is also one of the most important solutions for classical power electronic problems. Unlike the APF, the PPF consists of passive electronic elements R (resistor), L (inductor) and C (capacitor). The PPF can be further divided into shunt filter and series filter in terms of different connection topologies. A study is conducted in [75] to investigate the impacts of the PPF on harmonic mitigation in large wind farms. Several PPF designs and corresponding optimization methods are proposed, including the LCL filter, the LCL filter with damping resistors, second order high pass filter, third order high pass filter, switching frequency trap filter, C-type filter and the C-type with switching frequency trap filter. The mitigation performance of all the above PPFs quantified by voltage THD values and current THD values at the PCC is shown in Table 3-4. It should be noted that all modelling parameters of the PPF are optimized in order to maximize the mitigation effect of the filters. As can be seen from Table 3-4, the C-type with switching frequency trap filter is the most effective PPF design since it results in the lowest voltage and current THD values.

Table 3-4: Voltage THD values and current THD values at PCC with different types of PPF [75].

<table>
<thead>
<tr>
<th>Filter Type</th>
<th>Voltage THD (%)</th>
<th>Current THD (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Without Filter</td>
<td>10.4</td>
<td>5.6</td>
</tr>
<tr>
<td>LCL filter</td>
<td>4.57</td>
<td>3.6</td>
</tr>
<tr>
<td>LCL filter with damping resistors</td>
<td>2.74</td>
<td>3.49</td>
</tr>
<tr>
<td>Second order high pass filter</td>
<td>2.8</td>
<td>3.6</td>
</tr>
<tr>
<td>Third order high pass filter</td>
<td>3</td>
<td>4.02</td>
</tr>
<tr>
<td>Switching frequency trap filter</td>
<td>2.67</td>
<td>3.83</td>
</tr>
<tr>
<td>C-type filter</td>
<td>2.9</td>
<td>4.6</td>
</tr>
<tr>
<td>C-type with switching frequency trap</td>
<td>1.1</td>
<td>2.45</td>
</tr>
</tbody>
</table>

By comparing the APF and the PPF implemented in the power system, Table 3-5 [76] summarises the differences between these two harmonic mitigation technologies in terms of several indices. Due to the simpler design and economic advantages, the PPF is a mature solution for harmonic mitigation of wind farms. It can be considered in the early stage of wind farm design and construction to adjust harmonic distortion within predefined ranges. However, since the PPF only contains passive elements (R, L and C), the functions provided by the PPF are less than those of the APF. The values of R, L and C have to be calculated and tuned carefully in order to make the PPF work properly. In contrast, the APF adopts active electronic elements to provide both harmonic mitigation and reactive power compensation to the system. A typical PPF applied in transmission level at the point of WF connection contains detuned C-type filters and double-tuned filters, etc. Typical APF applied at the connection point of WF contains shunt connected FACTS devices and an HVDC link, etc. [76]. The main barriers to APF implementation are the relatively shorter life span and the higher costs compared with the PPF due to an additional control circuit and expensive electronic components.
From the above discussion, it can be seen that the improvement and robust design of WECS converters mainly enable the GSC or the RSC to operate as the APF such that the compensation currents can be generated to cancel harmonic currents injected by the other harmonic sources at the PCC. Moreover, the implementation of harmonic filters is another effective method improving system harmonic issues. They are usually applied in an early stage of wind farm design and construction. Due to their low cost and easy control strategy, harmonic filters have been widely used.

Table 3-5: Comparison between PPF and APF in terms of several indices [76].

<table>
<thead>
<tr>
<th>Indices</th>
<th>PPF</th>
<th>APF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technology</td>
<td>Mature</td>
<td>Improving</td>
</tr>
<tr>
<td>Reliability</td>
<td>High</td>
<td>Medium</td>
</tr>
<tr>
<td>Effectiveness</td>
<td>Medium</td>
<td>Good</td>
</tr>
<tr>
<td>Life Span</td>
<td>Large</td>
<td>Medium</td>
</tr>
<tr>
<td>Power Electronics</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Energy Storage</td>
<td>Large</td>
<td>Small</td>
</tr>
<tr>
<td>Control Circuit</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Voltage Regulation</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Dynamic Response</td>
<td>Slow</td>
<td>Fast</td>
</tr>
<tr>
<td>Cost</td>
<td>Low</td>
<td>High</td>
</tr>
</tbody>
</table>

Table 3-6 roughly compares the effectiveness of different harmonic mitigation strategies discussed above. Note that the values are estimated as there are several items (such as harmonic distortion rate before mitigation, the filter’s size, modulation technique, VF-APF control strategy, etc.) that need to be taken into consideration to extract accurate comparison. Furthermore, only harmonic distortion of the mitigation point (before and after the implementation of the mitigation strategy) was considered to calculate the percentage of harmonic reduction. From Table 3-6 it can be concluded that the reconfiguration of wind farms is the least effective, while the deployment of VF-APF is the most effective in harmonic reduction.
Table 3-6: Effectiveness of different types of harmonic mitigation strategies.

<table>
<thead>
<tr>
<th>Mitigation strategy</th>
<th>Percentage of harmonic reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Converter's output filter</td>
<td>55%-75% (THD of Voltage)</td>
</tr>
<tr>
<td>VF-APF</td>
<td>85%-95% (THD of Voltage)</td>
</tr>
<tr>
<td>Reconfiguration of wind farm</td>
<td>5%-35% (THD of Voltage)</td>
</tr>
<tr>
<td>Modulation</td>
<td>50%-80% (THD of Current)</td>
</tr>
<tr>
<td>Passive filters</td>
<td>40%-95% (THD of Voltage)</td>
</tr>
</tbody>
</table>

3.4 Harmonic Mitigation Control Methods

In this section, harmonic mitigation methods for individual devices will be presented. Regarding the harmonic sources in the power network, we will focus on the following three:

- nonlinear operation of PE-devices;
- switching harmonics (harmonics near switching frequency);
- control algorithms of PE-devices.

These three categories of harmonics sources are also among the main contributors of harmonics emissions in the power system [37]. Thus, in developing the mitigation methods we will focus on these three main sources of harmonic emissions.

3.4.1 Harmonic Mitigation with Statcom

In transmission systems, the Statcom is primarily used to increase the transmission capacity and enhance voltage stability, whereas the application in distribution systems is focused on voltage regulation. At the same time, Statcom also can be a source of unwanted harmonic current emissions that are caused by the nonlinear characteristic of the device itself, by the control actions of the device and by the switching actions of the semiconductor switches.

Since Statcom is an active device that is capable of tracking (measuring) harmonics currents (also its own) in real-time and injecting appropriate harmonics currents in the network that cancel out the harmonics, this principle (also known as self-compensation) should be investigated and if it proves effective, it should be more often implemented in Statcom applications. The basic principle is shown in Figure 3-11. As it can be seen from the figure, the Statcom operates as a pure sinusoidal source, even though the network voltage and current is distorted.
The self-compensation algorithm, explained below, will be implemented on a MMC Statcom model that has been developed within Deliverable D5.2 of the MIGRATE project [24]. However, the existing fundamental frequency (decoupled vector) controller, depicted in Figure 3-12, was upgraded with the harmonic frequencies controllers, what is presented in this section. A scheme of the StatCom converter topology as it has been modelled, is shown in Figure 3-13.
a) Figure 3-13: Scheme of the STATCOM converter topology a) and detailed model of an individual converter leg b).

The proposed vector controller design for harmonics (in Figure 3-14) is based on the fundamental harmonic controller topology (PI control law), described in Section 3.2. Control of each individual harmonic component adds an additional controller tuned to the frequency of the selected harmonic. The number of individual harmonic control loops is arbitrary and it depends on the specific case.

Note that the input current into the controller is Statcom’s current ($i_{act}$), which results in compensation of those currents. The algorithm can be described as self-compensation controller, because it filters directly only harmonics in its output current. As a results, the harmonic emissions of the device are reduced substantially, what will be demonstrated in the results section.

b) Figure 3-14: Single line diagram of a harmonic controller for Statcom.
3.4.2 Harmonic Mitigation with PV Generators

PV systems are connected to the network with or without battery storage via a power converter in 2- or 3-level topology. A 2-level IGBT converter is shown in Figure 3-15.

![Figure 3-15: 2-level IGBT converter.](image)

For high power PV plants, the connection to the grid is usually done with a three-phase inverter to connect to the grid using a transformer (Figure 3-16).

![Figure 3-16: PV system and the grid.](image)

The inverter shown in Figure 3-15 causes harmonic distortion of the voltage and current on the alternating side during its operation, which is the result of switching of the inverter switches. Distortion can be reduced, but not completely eliminated, by different connection of the inverter and the proper design of the coupling impedance (or coupling filter). In this section, we will focus the later, i.e. on the design considerations of the coupling impedance in order to reduce emissions of harmonics from PVs as much as possible.

Different coupling impedances will be analysed and their effect on the reduction of harmonics emission will be shown later in the results section. The proposed solutions will be implemented on the PV/battery model that has been developed within D5.2 [24] and is represented by the Figure 3-17.
3.4.2.1 Coupling Impedance and its Effect on Harmonic Emissions Reduction

Converters are connected to the network via different coupling impedances, also commonly referred to as output filters. They have the function of filtering the high harmonic components resulting from the switching of the switching elements, as well as some protective functions. The coupling impedance variants can be roughly divided into the first-order inductive filters (L), second-order filters (LC), third-order filters (LCL) and high-pass filters. Since the LC filter is just a special case of the LCL filter, assuming that the influence of the second inductance is negligible, then only the L, LCL and high-pass filters will be considered below.

3.4.2.1.1 First-order Inductive Filter

The use of the L filter is shown in Figure 3-18, which shows a simplified single-phase scheme of a voltage converter with an output filter. It is worth noting that such a filter is often used in other applications, such as inverters for powering motor drives. The inductance $L_{af}$ and the resistivity $R_{af}$ are the filter inductance and the equivalent series resistance. The $u_{af}$ voltage is the filter output voltage and the $u_{PCC}$ voltage is the voltage at the filter connection point. It should be noted that the output of the inverter filter model is not affected (i.e. its filtering characteristics) by other elements connected to the device in parallel (e.g. non-linear load) or in series with the network.

Low-pass filter in Figure 3-18 can be mathematically represented with the transfer function equation:

$$H_L(s) = \frac{l_{af}(s)}{u_{af}(s)} = \frac{1}{sL_{af} + R_{af}}, \quad (3.2)$$

Figure 3-20 shows the Bode diagram of the transfer function $H_L(s)$. It can be seen that the amplitude characteristic is almost linear at higher frequencies, and the damping increases with increasing frequency - thus it is a low-pass filter.
Other characteristics of the first-order inductive filters can be summarized as follows:
- simple and cost effective;
- individual loads;
- typical impedance values: 2 %, 3 %, 5 %, 7.5 %.

![First-order inductive filter](image)

**Figure 3-18:** First-order inductive filter.

### 3.4.2.1.2 Second-order LC filters and third-order LCL filters

Recently, LCL filters have been increasingly used for harmonic filtering due to switching, primarily because of better filtering characteristics. Such a filter is shown in Figure 3-19, \( L_{af1} \) and \( R_{af1} \) are the inductance and the equivalent series resistance on the filter side, and \( L_{af2} \) and \( R_{af2} \) are the inductance and the equivalent series resistance on the converter side. \( C_{af} \) and \( R_c \) are filter capacitance and resistance, which is also a damping resistance that is sometimes added to dampen resonant states. \( i_{af1} \) and \( i_{af2} \) are the currents on the network and inverter side.

![Third-order LCL filter](image)

**Figure 3-19:** Third-order LCL filter.

The relationships between the voltages and current in Figure 3-19 can be mathematically described with the following two admittances:

\[
Y_{af1}(s) = \frac{i_{af1}(s)}{u_c(s) - u_{PCC}(s)} = \frac{1}{sL_{af1} + R_{af1}},
\]

\[
Y_{af2}(s) = \frac{i_{af2}(s)}{u_{af}(s) - u_c(s)} = \frac{1}{sL_{af2} + R_{af2}},
\]

The advantages of an LCL filter as compared to a simple L filter can be summarized as follows:
- A faster decrease in amplification at frequencies above the tuning frequency \( f_{res} \), which is the result of a higher order (third order) transfer function. As a result, the LCL filter better filters
the harmonics that result from the switching of semiconductor switches. This can be seen from Figure 3-20, which shows the Bode diagrams of the two filters.

- The smaller dimensions of the elements to achieve the same filtering characteristics, which follows directly from the previous point.

The main disadvantages of LCL filter compared to L filter are:

- A more complex structure. There have been many articles in the professional literature on the many issues of designing LCL output filters.
- Resonance phenomenon at \( f_{\text{res}} \), which can lead to unstable operation of the device or large harmonic distortion of the output values, if not properly designed. Resonance can be damped by a properly sized \( R_c \) resistor, but this causes additional energy losses.
- Due to variations in the parameters of the filter elements and the network, the tuning frequency of the filter can vary significantly over the years. Also, the resonance frequency changes, which can lead to unwanted harmonic resonance amplifications.

![Bode diagram of L- and LCL-filters](image)

*Figure 3-20: Bode diagram of L- and LCL-filters.*
3.4.2.1.3 High-Pass Filters

The topology in Figure 3-21 is often used to filter load current harmonics, for large variety of applications. The filter represents a high-pass parallel filter that is tuned so that the serial resonance between the choke and the capacitor represents a low impedance at broad spectrum of harmonics above the tuned frequency. Due to the low impedance, the harmonic currents are redirecting into the filter.

This type of a filter is not a typical solution for a coupling impedance, mainly due to the higher losses at fundamental frequency and also due to the higher price, however we shall consider it as an option because of the (generally known) good filtering characteristics.

![Figure 3-21: A simplified representation of a high-pass output filter.](image)

3.4.3 Harmonic Mitigation with SVC

The SVC (Figure 3-22) is connected in parallel to the network. It is intended to regulate the voltage profile and reactive power in the network. Active power flows can only be indirectly affected by the voltage regulation. In the analysis of the harmonic mitigation methods for SVC, we will focus on the passive filters of the SVC device that are primarily added to provide the capacitive reactive power, however their second purpose is to filter harmonic produced by the thyristors controlled reactor (TCR) of the SVC.

We will propose a new filter design that will present an optimal design in terms of the impedance-resonance characteristics and harmonics reductions. Namely, with each new installation of an SVC device, thorough analysis of the impedance characteristics is required, since characteristics can be completely different from one side to the other and no general approach in the designing of the passive filters is possible.

The proposed filter design will be implemented on the SVC model that has been developed within D5.2 [24] and is represented in Figure 3-22. As it can be seen, the already developed model consists of two banks of filters, with tuning frequencies 141 Hz and 190 Hz. As we will show bellow, a different filter design is more appropriate in this particular case.
Figure 3-22: Scheme of the harmonic filters and TCR model in PSCAD.

The harmonic content of the TCR current for different firing angles is shown in Figure 3-23. As it can be seen from the figure, TCR produces only odd harmonics and their amplitude heavily depends on the firing angle of the thyristors.

Figure 3-23: The harmonic content of the TCR current at different firing angles [77].

Figure 3-24 and 3-25 show impedance-frequency characteristics at the point of common coupling (PCC) and harmonic current emissions are shown for two cases: upper figure for passive filters tuned to the 3rd and 4th harmonic component (initial case) and lower figure for filters tuned to 5th and 7th
harmonic component with an additional HPF added as a third passive filter. The tuning frequencies were determined with analysis of the impedance-frequency characteristics. From Figure 3-24 one can see that with this passive filters arrangement there is a 5\textsuperscript{th} harmonic component in the SVC current that reaches high values due to the high impedance value at this component. The 5\textsuperscript{th} harmonic current is generated by the TCR element. Thus, we propose the lowest tuning frequency to be close to the 5\textsuperscript{th} harmonic.

The same applies also for the 7\textsuperscript{th} harmonic. It is generated by the TCR element and amplified by the impedance characteristics. Tuning second filter close to the 7\textsuperscript{th} harmonic reduces its level. Higher harmonics can be reduced with a high-pass filter (HPF). As it can be seen by comparing Figures 3-24 and 3-25, HPF filter reduces impedance values over a wider range of higher harmonics.

A simplified single line diagram of the proposed SVC design is shown in Figure 3-26. Compared to the initial set-up in Figure 3-22, one can note that there is one additional passive filter added and tuning frequencies are modified. TCR device stays unchanged in both cases.

Figure 3-24: The impedance-frequency characteristics from the SVC PCC, initial (generic) case.

Figure 3-25: The impedance-frequency characteristics from the SVC PCC, proposed design.
3.5 Simulation Models of Harmonic Mitigation Control Methods

EMT simulation models have been presented in details in D5.2 [24] and some of them have been further upgraded and used within this section to demonstrate device-based mitigation solutions (self-compensation, passive filtering, coupling impedance/filters), described in the previous section. Models have been analysed using frequency scanning method that gives results as Norton equivalents, i.e. frequency-dependent admittance and current source of the Norton equivalent (see Figure 3-27). All results that will be shown in the following section were obtained with simulation of EMT models under steady-state conditions.

In modelling of the individual devices, focus was on exact modelling of the main converter elements and harmonic mitigation solutions, modelling of main control algorithms functionalities and detailed model of harmonic filtering controls and representation of harmonic emissions based on:

- nonlinear operation;
- switching harmonics (harmonics near switching freq.);
- control algorithms.

![Figure 3-26: The impedance-frequency characteristics from the SVC PCC, proposed design.](image)

![Figure 3-27: The frequency-dependent Norton equivalent.](image)
3.5.1.1 Statcom Simulation Model

Main Statcom model data:
- \( U_{\text{rms}} = 380 \) kV
- \( I_{\text{rms}} = 75.96 \) A
- Time instant of results capture \( t = 3.2 \) s

Table 3-7: Main data of the Statcom model

<table>
<thead>
<tr>
<th>Statcom</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Topology</td>
<td>MMC; 10 modules per leg (same for both cases - with and without self-compensation)</td>
</tr>
<tr>
<td>Nominal power</td>
<td>85 MVAr</td>
</tr>
<tr>
<td>Nominal voltage</td>
<td>20 kV</td>
</tr>
</tbody>
</table>

Main active controls of the Statcom
- Reactive power reference control | Enabled |
- Self-compensation | Enabled |
- Simple grid model | |

| Grid voltage | 400 kV |
| Short-circuit power of the 400 kV grid | 20000 MVA |
| Step-up transformer | 400 kV / 20 kV |

3.5.1.2 PV Generators Simulation Model

Main PV-generators data:
- \( U_{\text{rms}} = 35 \) kV
- \( I_{\text{rms}} = 6.69 \) A
- \( t = 3.5 \) s

Table 3-8: Main data of the PV model

<table>
<thead>
<tr>
<th>PV-units</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Topology 1</td>
<td>2-level converter (L output filter)</td>
</tr>
<tr>
<td>Topology 2</td>
<td>2-level converter, (LCL output filter)</td>
</tr>
<tr>
<td>Nominal power</td>
<td>250 kVA</td>
</tr>
<tr>
<td>Nominal voltage</td>
<td>35 kV</td>
</tr>
</tbody>
</table>

Main active controls of the PV
- Self-compensation | Disabled |
- Simple grid model | |

| Grid voltage | 35 kV |
| Short-circuit power of the 400 kV grid | 2000 MVA |
| Step-up transformer | 35 kV / 0.69 kV |
3.5.1.3 SVC Simulation Model

Static VAR compensator enables regulation of network parameters, such as voltage, frequency, etc. with exchange of inductive or capacitive current with the network. It is connected in parallel and enables operation in two different modes; variable reference reactive power at constant PCC voltage and constant firing angle of TCR during PCC voltage variation.

In order to perform analysis of the PCC voltage influence on the current harmonics case with the constant firing angle at different network voltages was simulated. Filter capacitors and the controllable element of the SVC, TCR, are connected to the 20 kV network level. The device is connected to the high voltage level 400 kV with the step-up transformer.

SVC has two filter capacitors beside TCR. First, the filters were tuned to the resonant frequency around 3rd and 4th harmonic component in order to compensate the harmonics, produced by the TCR. Second, the filters were tuned to the resonant frequency around 5th and 7th harmonic component in order to self-compensate and also partially compensate network harmonics or better said, the resonant interactions between SVC and the network.

<table>
<thead>
<tr>
<th>Table 3-9: Main data of the SVC model</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SVC</strong></td>
</tr>
<tr>
<td>SVC topology 1</td>
</tr>
<tr>
<td>SVC topology 2</td>
</tr>
<tr>
<td>Nominal power</td>
</tr>
<tr>
<td>Nominal voltage</td>
</tr>
<tr>
<td><strong>Main active controls of the SVC/TCR</strong></td>
</tr>
<tr>
<td>Reactive power reference control</td>
</tr>
<tr>
<td>Simple grid model</td>
</tr>
<tr>
<td>Grid voltage</td>
</tr>
<tr>
<td>Short-circuit power of the 400 kV grid</td>
</tr>
<tr>
<td>Step-up transformer</td>
</tr>
</tbody>
</table>
3.6 Simulation Results

In the following subchapters, simulation results for individual PE-devices are shown in the following order: stead-state operation without device-based mitigation method, stead-state operation with device based mitigation methods and frequency impedance scanning results. All results are presented for different operating point. Some simulation results, namely harmonic reduction factors for each PE-device, can be found in the Appendix A.

3.6.1 Statcom Simulation Results

In this section, the emission of the harmonics is verified at constant output power and different network voltage levels (from 0.9 p.u. to 1.1 p.u.). Constant output power means also constant current harmonic injections that are produced by the controller and switching actions.

3.6.1.1 Steady-state operation at different network voltage levels and constant reactive power - results without self-compensation

In Table 3-10, result for voltages, currents and power during steady-state operation at different network voltage levels, without self-compensation mitigation method are shown. As it can be seen, the distortion levels of current are very low with the investigated StatCom MMC topology. In Table 3-11, individual output current harmonics (harmonic emission) during steady-state operation at different network voltage levels, without self-compensation are presented. It should be noted that 7th harmonic is reaching the highest value.

Table 3-10: Voltages, currents and power during steady-state operation at different network voltage levels (without self-compensation).

<table>
<thead>
<tr>
<th>U</th>
<th>U_{RMS}</th>
<th>U_{THD}</th>
<th>U_1</th>
<th>I_{RMS}</th>
<th>I_{THD}</th>
<th>I_1</th>
<th>P</th>
<th>Q</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>[kV]</td>
<td>[%]</td>
<td>[%]</td>
<td>[A]</td>
<td>[%]</td>
<td>[A]</td>
<td>[MW]</td>
<td>[MVAr]</td>
</tr>
<tr>
<td>U = 0.9</td>
<td>342,00</td>
<td>0,001</td>
<td>90,00</td>
<td>67,52</td>
<td>0,020</td>
<td>88,89</td>
<td>-0,03</td>
<td>40,02</td>
</tr>
<tr>
<td>U = 0.95</td>
<td>361,00</td>
<td>0,001</td>
<td>95,00</td>
<td>63,93</td>
<td>0,016</td>
<td>84,16</td>
<td>-0,03</td>
<td>40,01</td>
</tr>
<tr>
<td>U = 1.0</td>
<td>379,96</td>
<td>0,001</td>
<td>99,99</td>
<td>60,75</td>
<td>0,018</td>
<td>79,98</td>
<td>-0,05</td>
<td>40,01</td>
</tr>
<tr>
<td>U = 1.05</td>
<td>399,00</td>
<td>0,001</td>
<td>105,00</td>
<td>57,89</td>
<td>0,017</td>
<td>76,21</td>
<td>-0,08</td>
<td>40,00</td>
</tr>
<tr>
<td>U = 1.1</td>
<td>418,00</td>
<td>0,001</td>
<td>110,00</td>
<td>55,28</td>
<td>0,026</td>
<td>72,78</td>
<td>-0,06</td>
<td>39,98</td>
</tr>
</tbody>
</table>
Table 3-11: Output current harmonics during steady-state operation at different network voltage levels (without self-compensation).

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>Harmonic current</th>
<th>U=0.9</th>
<th>U=0.95</th>
<th>U=1.0</th>
<th>U=1.05</th>
<th>U=1.1</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2.</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td></td>
<td>3.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>4.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
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<td>5.</td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>7.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
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<td>9.</td>
<td></td>
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<td></td>
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<td></td>
</tr>
<tr>
<td></td>
<td>11.</td>
<td></td>
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<td></td>
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<td></td>
</tr>
<tr>
<td></td>
<td>13.</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>15.</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td></td>
<td>17.</td>
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<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>19.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>21.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>23.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>25.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

3.6.1.2 Steady-State Operation at Different Network Voltage Levels and Constant Reactive Power - Results with Self-Compensation

In Table 3-12, result for voltages, currents and power during steady-state operation at different network voltage levels, with self-compensation mitigation method are shown. As it can be seen, the distortion levels of current are reduced by a factor of 2-5-times, depending on the operating point, compared to the simulation results in Table 3-10 (without self-compensation). In Table 3-13, individual output current harmonics (harmonic emission) during steady-state operation at different network voltage levels, with self-compensation are presented. It should be noted that 7th harmonic reduced significantly compared to the results Table 3-11.

Comparing results with and without self-compensation mitigation solution, one can conclude that reduction of harmonic values is significant (e.g. on average eight times lower values for 7th harmonic) and that such mitigation is justified.
Table 3-12: Voltages, currents and power during steady-state operation at different network voltage levels (with self-compensation).

<table>
<thead>
<tr>
<th>Voltage level (pu)</th>
<th>U_{RMS} [kV]</th>
<th>U_{THD} [%]</th>
<th>U_1 [A]</th>
<th>I_{RMS} [A]</th>
<th>I_{THD} [%]</th>
<th>I_1 [%]</th>
<th>P [MW]</th>
<th>Q [MVAr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>U = 0.9</td>
<td>341.96</td>
<td>0,001</td>
<td>89.99</td>
<td>67.54</td>
<td>0,011</td>
<td>88,91</td>
<td>0,10</td>
<td>40,00</td>
</tr>
<tr>
<td>U = 0.95</td>
<td>361.00</td>
<td>0,001</td>
<td>95.00</td>
<td>63.97</td>
<td>0,008</td>
<td>84,21</td>
<td>0,04</td>
<td>40,00</td>
</tr>
<tr>
<td>U = 1.0</td>
<td>379.96</td>
<td>0,001</td>
<td>99.99</td>
<td>60.84</td>
<td>0,005</td>
<td>80,09</td>
<td>-0,04</td>
<td>39,99</td>
</tr>
<tr>
<td>U = 1.05</td>
<td>399.00</td>
<td>0,001</td>
<td>105.00</td>
<td>57.88</td>
<td>0,009</td>
<td>76,20</td>
<td>-0,06</td>
<td>39,99</td>
</tr>
<tr>
<td>U = 1.1</td>
<td>418.00</td>
<td>0,001</td>
<td>110.00</td>
<td>55.26</td>
<td>0,009</td>
<td>72,75</td>
<td>-0,10</td>
<td>40,00</td>
</tr>
</tbody>
</table>

Table 3-13: Output current harmonics during steady-state operation at different network voltage levels (with self-compensation).

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>Harmonic current</th>
<th>Harmonic current</th>
<th>Harmonic current</th>
<th>Harmonic current</th>
<th>Harmonic current</th>
<th>Harmonic current</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>U=0.9</td>
<td>U=0.95</td>
<td>U=1.0</td>
<td>U=1.05</td>
<td>U=1.1</td>
<td></td>
</tr>
<tr>
<td>1.</td>
<td>l_1 [%]</td>
<td>88.91</td>
<td>84.21</td>
<td>80.09</td>
<td>76.20</td>
<td>72.75</td>
</tr>
<tr>
<td>2.</td>
<td>0.08</td>
<td>0.04</td>
<td>0.03</td>
<td>0.06</td>
<td>0.05</td>
<td></td>
</tr>
<tr>
<td>3.</td>
<td>0.18</td>
<td>0.07</td>
<td>0.06</td>
<td>0.09</td>
<td>0.08</td>
<td></td>
</tr>
<tr>
<td>4.</td>
<td>0.21</td>
<td>0.18</td>
<td>0.10</td>
<td>0.09</td>
<td>0.05</td>
<td></td>
</tr>
<tr>
<td>5.</td>
<td>0.50</td>
<td>0.15</td>
<td>0.07</td>
<td>0.15</td>
<td>0.01</td>
<td></td>
</tr>
<tr>
<td>7.</td>
<td>0.08</td>
<td>0.11</td>
<td>0.01</td>
<td>0.13</td>
<td>0.13</td>
<td></td>
</tr>
<tr>
<td>9.</td>
<td>0.09</td>
<td>0.06</td>
<td>0.02</td>
<td>0.06</td>
<td>0.31</td>
<td></td>
</tr>
<tr>
<td>11.</td>
<td>0.32</td>
<td>0.18</td>
<td>0.06</td>
<td>0.19</td>
<td>0.29</td>
<td></td>
</tr>
<tr>
<td>13.</td>
<td>0.10</td>
<td>0.19</td>
<td>0.07</td>
<td>0.10</td>
<td>0.17</td>
<td></td>
</tr>
<tr>
<td>15.</td>
<td>0.04</td>
<td>0.05</td>
<td>0.03</td>
<td>0.06</td>
<td>0.16</td>
<td></td>
</tr>
<tr>
<td>17.</td>
<td>0.07</td>
<td>0.14</td>
<td>0.02</td>
<td>0.14</td>
<td>0.06</td>
<td></td>
</tr>
<tr>
<td>19.</td>
<td>0.17</td>
<td>0.14</td>
<td>0.02</td>
<td>0.03</td>
<td>0.18</td>
<td></td>
</tr>
<tr>
<td>21.</td>
<td>0.07</td>
<td>0.07</td>
<td>0.02</td>
<td>0.03</td>
<td>0.05</td>
<td></td>
</tr>
<tr>
<td>23.</td>
<td>0.04</td>
<td>0.06</td>
<td>0.05</td>
<td>0.18</td>
<td>0.23</td>
<td></td>
</tr>
<tr>
<td>25.</td>
<td>0.14</td>
<td>0.51</td>
<td>0.23</td>
<td>0.53</td>
<td>0.27</td>
<td></td>
</tr>
</tbody>
</table>

3.6.1.3 Frequency Impedance Scanning – Statcom

Frequency impedance scanning was performed for different operating points – at constant output power and different network voltage levels (from 0.9 pu to 1.1 pu). First, the Statcom was scanned without self-compensation. Later on, the self-compensation solution was added to the controller of the Statcom. Figures 3-28 and 3-29 show characteristics of Norton equivalent circuit for positive (red) and negative (blue) sequence. The same characteristic is marked with the same colour for all operating points. The impedance of the Norton equivalent describes the influence of the Statcom controller on the impedance values. Individual harmonic control loops can be observed as narrow spikes in the characteristic at corresponding harmonic components. The lower the spikes the more...
effective filtering is. Again, as already seen in tables Table 3-10 – Table 3-13, the harmonic current emissions are reduced significantly with the self-compensation mitigation method.

Figure 3-28: Statcom Norton equivalent – Frequency-dependent impedance (amplitude) and current source (amplitude) for operating without self-compensation and variable network voltage (0.9 pu to 1.1 pu).

Figure 3-29: Statcom Norton equivalent – Frequency-dependent impedance (amplitude) and current source (amplitude) for operating with self-compensation and variable network voltage (0.9 pu to 1.1 pu).
3.6.2 PV Generators Simulation Results

In this section, the emission of the harmonics is verified at constant output active power 1 p.u. and different network voltage levels (from 0.9 p.u. to 1.1 p.u.). Constant output power means constant current harmonic injections. The PV-generator model is implemented with different coupling impedances, as presented in Section 3.4.2.

3.6.2.1 Steady-State Operation at Different Network Voltage Levels and Constant Active/Reactive Power - Results without Inductance only

In Table 3-14, result for voltages, currents and power during steady-state operation at different network voltage levels, with inductance as a coupling impedance are shown. Fundamental component voltage and current values for individual operating points are presented, and harmonic voltage and current distortions (THD values) are given. In Table 3-15, individual harmonic components values are given. The lower harmonics are reaching the highest values, which is mainly due to the topology of the converter.

Table 3-14: Voltages, currents and power during steady-state operation at different network voltage levels (with inductance only).

<table>
<thead>
<tr>
<th>U</th>
<th>U_RMS [kV]</th>
<th>U_THD [%]</th>
<th>U_1 [%]</th>
<th>I_RMS [A]</th>
<th>I_THD [%]</th>
<th>I_1 [%]</th>
<th>P [MW]</th>
<th>Q [MVAr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.9</td>
<td>31.50</td>
<td>0.001</td>
<td>90.00</td>
<td>7.44</td>
<td>0.027</td>
<td>111.21</td>
<td>0.39</td>
<td>0.04</td>
</tr>
<tr>
<td>0.95</td>
<td>33.25</td>
<td>0.001</td>
<td>95.01</td>
<td>7.04</td>
<td>0.029</td>
<td>105.23</td>
<td>0.39</td>
<td>0.04</td>
</tr>
<tr>
<td>1.0</td>
<td>35.01</td>
<td>0.001</td>
<td>100.03</td>
<td>6.68</td>
<td>0.023</td>
<td>99.88</td>
<td>0.39</td>
<td>0.03</td>
</tr>
<tr>
<td>1.05</td>
<td>36.74</td>
<td>0.001</td>
<td>104.98</td>
<td>6.34</td>
<td>0.038</td>
<td>94.76</td>
<td>0.39</td>
<td>0.03</td>
</tr>
<tr>
<td>1.1</td>
<td>38.51</td>
<td>0.001</td>
<td>110.02</td>
<td>5.97</td>
<td>0.029</td>
<td>89.17</td>
<td>0.39</td>
<td>0.04</td>
</tr>
</tbody>
</table>
### Table 3-15: Output current harmonics during steady-state operation at different network voltage levels (with inductance only).

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>Harmonic current</th>
<th>U=0.9</th>
<th>U=0.95</th>
<th>U=1.0</th>
<th>U=1.05</th>
<th>U=1.1</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Iₜₜ [%]</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.</td>
<td>111.21</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>89.17</td>
</tr>
<tr>
<td>2.</td>
<td>1.99</td>
<td>0.84</td>
<td>1.57</td>
<td>3.05</td>
<td>2.29</td>
<td></td>
</tr>
<tr>
<td>3.</td>
<td>1.37</td>
<td>2.67</td>
<td>0.71</td>
<td>1.97</td>
<td>0.92</td>
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</tr>
<tr>
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<td>0.89</td>
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<td>1.21</td>
<td>0.95</td>
<td>0.96</td>
<td></td>
</tr>
<tr>
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<td>0.54</td>
<td>0.42</td>
<td>1.27</td>
<td>0.85</td>
<td></td>
</tr>
<tr>
<td>6.</td>
<td>0.17</td>
<td>0.09</td>
<td>0.29</td>
<td>0.17</td>
<td>0.23</td>
<td></td>
</tr>
<tr>
<td>7.</td>
<td>0.11</td>
<td>0.26</td>
<td>0.23</td>
<td>0.03</td>
<td>0.21</td>
<td></td>
</tr>
<tr>
<td>8.</td>
<td>0.08</td>
<td>0.16</td>
<td>0.07</td>
<td>0.13</td>
<td>0.08</td>
<td></td>
</tr>
<tr>
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<td>0.03</td>
<td>0.02</td>
<td>0.04</td>
<td>0.05</td>
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<td>0.05</td>
<td>0.03</td>
<td>0.04</td>
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</tr>
<tr>
<td>11.</td>
<td>0.05</td>
<td>0.03</td>
<td>0.04</td>
<td>0.05</td>
<td>0.02</td>
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<td>0.03</td>
<td>0.01</td>
<td>0.01</td>
<td></td>
</tr>
<tr>
<td>13.</td>
<td>0.02</td>
<td>0.02</td>
<td>0.03</td>
<td>0.02</td>
<td>0.01</td>
<td></td>
</tr>
<tr>
<td>14.</td>
<td>0.01</td>
<td>0.03</td>
<td>0.02</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>15.</td>
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<td>0.01</td>
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<td>0.02</td>
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</tr>
<tr>
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<td>0.02</td>
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<td>0.02</td>
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<td>0.02</td>
<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
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<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>19.</td>
<td>0.01</td>
<td>0.02</td>
<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>20.</td>
<td>0.01</td>
<td>0.02</td>
<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>21.</td>
<td>0.01</td>
<td>0.02</td>
<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>22.</td>
<td>0.01</td>
<td>0.02</td>
<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>23.</td>
<td>0.01</td>
<td>0.02</td>
<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>24.</td>
<td>0.01</td>
<td>0.02</td>
<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
<tr>
<td>25.</td>
<td>0.01</td>
<td>0.02</td>
<td>0.01</td>
<td>0.02</td>
<td>0.02</td>
<td></td>
</tr>
</tbody>
</table>

### 3.6.2.2 Steady-State Operation at Different Network Voltage Levels and Constant Active/Reactive Power - Results with LCL Coupling Filters

In Table 3-16 and Table 3-17 simulation results are presented with an LCL filter as a coupling impedance. As it is clear from the tables, all harmonics values are reduced substantially, including the lower harmonics that reached highest values in the previous case, with only L filter as a coupling impedance. Such result is in line with the expectations, since LCL filter is superior in damping performance.

### Table 3-16: Voltages, currents and power during steady-state operation at different network voltage levels (with LCL coupling filters).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>U = 0.9</td>
<td>31.49</td>
<td>0.001</td>
<td>89.99</td>
<td>7.44</td>
<td>0.005</td>
<td>111.24</td>
</tr>
<tr>
<td>U = 0.95</td>
<td>33.29</td>
<td>0.001</td>
<td>95.11</td>
<td>7.06</td>
<td>0.002</td>
<td>105.48</td>
</tr>
<tr>
<td>U = 1.0</td>
<td>34.99</td>
<td>0.001</td>
<td>99.99</td>
<td>6.71</td>
<td>0.006</td>
<td>100.36</td>
</tr>
<tr>
<td>U = 1.05</td>
<td>36.75</td>
<td>0.001</td>
<td>105.01</td>
<td>6.36</td>
<td>0.007</td>
<td>95.09</td>
</tr>
<tr>
<td>U = 1.1</td>
<td>38.49</td>
<td>0.001</td>
<td>109.98</td>
<td>6.07</td>
<td>0.003</td>
<td>90.77</td>
</tr>
</tbody>
</table>
Table 3-17: Output current harmonics during steady-state operation at different network voltage levels (with LCL coupling filters).

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>Harmonic current</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>U=0.9</td>
</tr>
<tr>
<td></td>
<td>I_h [%]</td>
</tr>
<tr>
<td>1.</td>
<td>111.24</td>
</tr>
<tr>
<td>2.</td>
<td>0.16</td>
</tr>
<tr>
<td>3.</td>
<td>0.37</td>
</tr>
<tr>
<td>4.</td>
<td>0.09</td>
</tr>
<tr>
<td>5.</td>
<td>0.15</td>
</tr>
<tr>
<td>7.</td>
<td>0.06</td>
</tr>
<tr>
<td>9.</td>
<td>0.03</td>
</tr>
<tr>
<td>11.</td>
<td>0.03</td>
</tr>
<tr>
<td>13.</td>
<td>0.01</td>
</tr>
<tr>
<td>15.</td>
<td>0.02</td>
</tr>
<tr>
<td>17.</td>
<td>0.02</td>
</tr>
<tr>
<td>19.</td>
<td>0.02</td>
</tr>
<tr>
<td>21.</td>
<td>0.01</td>
</tr>
<tr>
<td>23.</td>
<td>0.00</td>
</tr>
<tr>
<td>25.</td>
<td>0.01</td>
</tr>
</tbody>
</table>

3.6.2.3 Steady-State Operation at Different Network Voltage Levels and Constant Active/Reactive Power - Results with High-Pass Coupling Filter

In Table 3-18 and Table 3-19 simulation results are presented for high-pass filter used as a coupling impedance. As expected, the results have again imposed, compared to the L and LCL filters. The results of all three coupling impedance types are compared in Figure 3-30.

Table 3-18: Voltages, currents and power during steady-state operation at different network voltage levels (with High-Pass filter).

<table>
<thead>
<tr>
<th></th>
<th>U_rms [kV]</th>
<th>U_THD [%]</th>
<th>U_1 [A]</th>
<th>I_rms [%]</th>
<th>I_THD [%]</th>
<th>I_1 [%]</th>
<th>P [MW]</th>
<th>Q [MVAr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>U = 0.9</td>
<td>31.54</td>
<td>&lt;0.001</td>
<td>90.11</td>
<td>7.45</td>
<td>0.004</td>
<td>111.32</td>
<td>0.39</td>
<td>0.03</td>
</tr>
<tr>
<td>U = 0.95</td>
<td>33.21</td>
<td>&lt;0.001</td>
<td>94.89</td>
<td>7.05</td>
<td>0.005</td>
<td>105.38</td>
<td>0.39</td>
<td>0.03</td>
</tr>
<tr>
<td>U = 1.0</td>
<td>35.01</td>
<td>&lt;0.001</td>
<td>100.03</td>
<td>6.70</td>
<td>0.007</td>
<td>100.09</td>
<td>0.39</td>
<td>0.03</td>
</tr>
<tr>
<td>U = 1.05</td>
<td>36.79</td>
<td>&lt;0.001</td>
<td>105.13</td>
<td>6.37</td>
<td>0.010</td>
<td>95.28</td>
<td>0.39</td>
<td>0.03</td>
</tr>
<tr>
<td>U = 1.1</td>
<td>38.49</td>
<td>&lt;0.001</td>
<td>109.98</td>
<td>6.10</td>
<td>0.014</td>
<td>91.18</td>
<td>0.40</td>
<td>0.04</td>
</tr>
</tbody>
</table>
Table 3-19: Output current harmonics during steady-state operation at different network voltage levels (with High-Pass filter).

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>Harmonic current</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>U=0.9</td>
</tr>
<tr>
<td>I&lt;sub&gt;h&lt;/sub&gt; [%]</td>
<td></td>
</tr>
<tr>
<td>1.</td>
<td>111,32</td>
</tr>
<tr>
<td>2.</td>
<td>0,07</td>
</tr>
<tr>
<td>3.</td>
<td>0,29</td>
</tr>
<tr>
<td>4.</td>
<td>0,11</td>
</tr>
<tr>
<td>5.</td>
<td>0,12</td>
</tr>
<tr>
<td>6.</td>
<td>0,06</td>
</tr>
<tr>
<td>7.</td>
<td>0,04</td>
</tr>
<tr>
<td>8.</td>
<td>0,03</td>
</tr>
<tr>
<td>9.</td>
<td>0,01</td>
</tr>
<tr>
<td>10.</td>
<td>0,00</td>
</tr>
<tr>
<td>11.</td>
<td>0,00</td>
</tr>
<tr>
<td>12.</td>
<td>0,00</td>
</tr>
<tr>
<td>13.</td>
<td>0,00</td>
</tr>
<tr>
<td>14.</td>
<td>0,00</td>
</tr>
<tr>
<td>15.</td>
<td>0,00</td>
</tr>
<tr>
<td>16.</td>
<td>0,00</td>
</tr>
<tr>
<td>17.</td>
<td>0,00</td>
</tr>
<tr>
<td>18.</td>
<td>0,00</td>
</tr>
<tr>
<td>19.</td>
<td>0,00</td>
</tr>
<tr>
<td>20.</td>
<td>0,00</td>
</tr>
<tr>
<td>21.</td>
<td>0,00</td>
</tr>
<tr>
<td>22.</td>
<td>0,00</td>
</tr>
<tr>
<td>23.</td>
<td>0,00</td>
</tr>
<tr>
<td>24.</td>
<td>0,00</td>
</tr>
<tr>
<td>25.</td>
<td>0,00</td>
</tr>
</tbody>
</table>

Figure 3-30: Comparison of current emissions during steady-state operation at 1 p.u. voltage, for different coupling impedances.
3.6.2.4 Frequency Impedance Scanning – PV Generators

Frequency Impedance scanning was performed for different operating points – at constant output power and different network voltage levels (from 0.9 pu to 1.1 pu). First, the L filter was scanned, followed by the LCL- and high-pass filters.

Figures show characteristics of Norton equivalent circuit for positive (red) and negative (blue) sequence. The same characteristic is marked with the same colour for all operating points. As it is clear from comparison of results in Figure 3-31 and Figures 3-32 and 3-33, the impedance of the Norton equivalent does not change noticeably; however, it does become smoother as the harmonic levels decrease. It is important to note that with the more advanced coupling filter all harmonic components decrease noticeably, which proves that the tuning of the filters has been done correctly. Damping of the output filter increases with higher frequencies.

Figure 3-31: PV-generator Norton equivalent – Frequency-dependent impedance (amplitude) and current source (amplitude) for operating with only inductance as coupling impedance and variable network voltage (0.9 pu to 1.1 pu).
Figure 3-32: PV generator Norton equivalent – Frequency-dependent impedance (amplitude) and current source (amplitude) for operating with LCL coupling impedance and variable network voltage (0.9 pu to 1.1 pu).

Figure 3-33: PV generator Norton equivalent – Frequency-dependent impedance (amplitude) and current source (amplitude) for operating with High-Pass filter as coupling impedance and variable network voltage (0.9 pu to 1.1 pu).

The impedance of the Norton equivalent does not change noticeably; however, it does become smoother as the harmonic levels decrease.
It is important to note that with the more advanced coupling filter all harmonic components decrease noticeably, which proves that the tuning of the filters has been done correctly. Damping of the output filter increases with higher frequencies.

3.6.3 SVC Simulation Results

In this section, the emissions of the harmonics is verified at constant firing angle and different network voltage levels (from 0.9 pu to 1.1 pu). Constant firing angle means constant current harmonic injections. Two different passive filter design options have been simulated, according to the section 3.4.3.

With first passive filter design, in tuning of the filters impedance-frequency characteristic of the network have not been considered, meaning that tuning is not optimal in terms of resonance damping. In the second design case, the frequency characteristic has been analysed and properly considered in tuning the filters.

3.6.3.1 Steady-state – Variation of the Network Voltage with Filters Tuned to Resonant Frequency Around 3\textsuperscript{rd} and 4\textsuperscript{th} Harmonic Component

In Table 3-20 and Table 3-21, voltages, currents and power during steady-state operation at different network voltage levels, with constant firing angle and filters tuned to 3\textsuperscript{rd} and 4\textsuperscript{th} harmonic component are shown. Results are presented separately for total harmonic distortion and for individual harmonics.

As it can be seen from the results, 5\textsuperscript{th} harmonic is in particular problematic, which is due to the parallel resonance of the compensators with the network. This influence will be clearly seen and explained in the following results.

<table>
<thead>
<tr>
<th>U</th>
<th>U\textsubscript{RMS}</th>
<th>U\textsubscript{THD}</th>
<th>U\textsuperscript{1}</th>
<th>I\textsubscript{RMS}</th>
<th>I\textsubscript{THD}</th>
<th>I\textsuperscript{1}</th>
<th>P</th>
<th>Q</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.9</td>
<td>359.56</td>
<td>0.001</td>
<td>89.89</td>
<td>53.29</td>
<td>0.011</td>
<td>52.74</td>
<td>1.12</td>
<td>49.00</td>
</tr>
<tr>
<td>0.95</td>
<td>379.68</td>
<td>0.001</td>
<td>94.92</td>
<td>56.25</td>
<td>0.011</td>
<td>55.67</td>
<td>1.26</td>
<td>54.57</td>
</tr>
<tr>
<td>1.0</td>
<td>400.72</td>
<td>0.001</td>
<td>100.18</td>
<td>59.19</td>
<td>0.011</td>
<td>58.59</td>
<td>1.26</td>
<td>60.28</td>
</tr>
<tr>
<td>1.05</td>
<td>420.72</td>
<td>0.001</td>
<td>105.18</td>
<td>62.27</td>
<td>0.011</td>
<td>61.63</td>
<td>1.54</td>
<td>66.42</td>
</tr>
<tr>
<td>1.1</td>
<td>439.72</td>
<td>0.001</td>
<td>109.93</td>
<td>65.13</td>
<td>0.011</td>
<td>64.46</td>
<td>1.75</td>
<td>73.14</td>
</tr>
</tbody>
</table>
Table 3-21: Output current harmonics during steady-state operation at different network voltage levels (constant firing angle, filters tuned to 3\textsuperscript{rd} and 4\textsuperscript{th} harmonic component).

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>Harmonic current</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>U=0.9</td>
</tr>
<tr>
<td>1</td>
<td>$I_h$ [%]</td>
</tr>
<tr>
<td>2</td>
<td>52.74</td>
</tr>
<tr>
<td>3</td>
<td>0.00</td>
</tr>
<tr>
<td>4</td>
<td>0.00</td>
</tr>
<tr>
<td>5</td>
<td>10.26</td>
</tr>
<tr>
<td>6</td>
<td>3.57</td>
</tr>
<tr>
<td>7</td>
<td>0.00</td>
</tr>
<tr>
<td>8</td>
<td>2.16</td>
</tr>
<tr>
<td>9</td>
<td>1.97</td>
</tr>
<tr>
<td>10</td>
<td>0.00</td>
</tr>
<tr>
<td>11</td>
<td>0.01</td>
</tr>
<tr>
<td>12</td>
<td>0.63</td>
</tr>
<tr>
<td>13</td>
<td>0.00</td>
</tr>
<tr>
<td>14</td>
<td>0.51</td>
</tr>
<tr>
<td>15</td>
<td>0.09</td>
</tr>
</tbody>
</table>

3.6.3.2 Steady-state – Variation of the Network Voltage with Filters Tuned to Resonant Frequency Around 5\textsuperscript{th} and 7\textsuperscript{th} Harmonic Component

In Table 3-22 and Table 3-23, voltages, currents and power during steady-state operation at different network voltage levels, with constant firing angle and filters tuned to 5\textsuperscript{th} and 7\textsuperscript{th} harmonic component are shown. Results are presented separately for total harmonic distortion and for individual harmonics. It can be seen that in particular 5\textsuperscript{th} harmonic is now reduced substantially. Most other components values are also reduced.

Table 3-22: Voltages, currents and power during steady-state operation at different network voltage levels (constant firing angle, filters tuned to 5\textsuperscript{th} and 7\textsuperscript{th} harmonic component).

<table>
<thead>
<tr>
<th>$U_{RMS}$ [kV]</th>
<th>$U_{THD}$ [%]</th>
<th>$U_1$ [A]</th>
<th>$I_{RMS}$ [A]</th>
<th>$I_{THD}$ [%]</th>
<th>$I_1$ [A]</th>
<th>$P$ [MW]</th>
<th>$Q$ [MVAr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>$U = 0.9$</td>
<td>359.56</td>
<td>0.001</td>
<td>89.89</td>
<td>58.15</td>
<td>0.003</td>
<td>57.55</td>
<td>1.05</td>
</tr>
<tr>
<td>$U = 0.95$</td>
<td>379.52</td>
<td>0.001</td>
<td>94.88</td>
<td>61.38</td>
<td>0.003</td>
<td>60.75</td>
<td>1.17</td>
</tr>
<tr>
<td>$U = 1.0$</td>
<td>400.72</td>
<td>0.001</td>
<td>100.18</td>
<td>64.62</td>
<td>0.003</td>
<td>63.95</td>
<td>1.33</td>
</tr>
<tr>
<td>$U = 1.05$</td>
<td>419.72</td>
<td>0.001</td>
<td>104.93</td>
<td>67.85</td>
<td>0.003</td>
<td>67.15</td>
<td>1.47</td>
</tr>
<tr>
<td>$U = 1.1$</td>
<td>439.96</td>
<td>0.001</td>
<td>109.99</td>
<td>71.07</td>
<td>0.003</td>
<td>70.34</td>
<td>1.57</td>
</tr>
</tbody>
</table>
Table 3-23: Output current harmonics during steady-state operation at different network voltage levels (constant firing angle, filters tuned to 5th and 7th harmonic component).

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>Harmonic current</th>
<th>U=0.9 [%]</th>
<th>U=0.95 [%]</th>
<th>U=1.0 [%]</th>
<th>U=1.05 [%]</th>
<th>U=1.1 [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td></td>
<td>57.55</td>
<td>60.75</td>
<td>63.95</td>
<td>67.15</td>
<td>70.34</td>
</tr>
<tr>
<td>2.</td>
<td></td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>3.</td>
<td></td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>4.</td>
<td></td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>5.</td>
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<td>2.66</td>
<td>2.67</td>
<td>2.67</td>
<td>2.68</td>
</tr>
<tr>
<td>7.</td>
<td></td>
<td>0.47</td>
<td>0.48</td>
<td>0.48</td>
<td>0.49</td>
<td>0.49</td>
</tr>
<tr>
<td>9.</td>
<td></td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>11.</td>
<td></td>
<td>0.54</td>
<td>0.54</td>
<td>0.55</td>
<td>0.55</td>
<td>0.56</td>
</tr>
<tr>
<td>13.</td>
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<td>0.58</td>
<td>0.58</td>
<td>0.58</td>
<td>0.59</td>
<td>0.59</td>
</tr>
<tr>
<td>15.</td>
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<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>17.</td>
<td></td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>19.</td>
<td></td>
<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
<td>0.24</td>
<td>0.25</td>
</tr>
<tr>
<td>21.</td>
<td></td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>23.</td>
<td></td>
<td>0.18</td>
<td>0.18</td>
<td>0.19</td>
<td>0.19</td>
<td>0.20</td>
</tr>
<tr>
<td>25.</td>
<td></td>
<td>0.03</td>
<td>0.03</td>
<td>0.03</td>
<td>0.04</td>
<td>0.04</td>
</tr>
</tbody>
</table>

3.6.3.3 Frequency Impedance Scanning – SVC

Frequency Impedance scanning was performed for different operating points – at constant firing angle (110°) and different network voltage levels (from 0.9 pu to 1.1 pu). First, the passive filters were tuned to 3rd and 4th harmonic components to provide self-compensation of the device. Later on, the passive filters were tuned to 5th and 7th harmonic components to provide self-compensations and in part also compensation of network harmonics.

Figure 3-34 and Figure 3-35 show characteristics of Norton equivalent circuit for positive (red) and negative (blue) sequence. The same characteristic is marked with the same colour for all operating points.

The impedance of the Norton equivalent describes the influence of the variable impedance of the TCR influencing the characteristic below resonances of the first harmonic filter, while in range of higher frequencies, the impedance is mostly defined by the two passive harmonic filters. Resonant frequency at which passive filters are tuned therefore impact the harmonic current injections of the SVC. As can be observed from figures, the harmonic currents are higher if passive filters are tuned to 3rd and 4th harmonics because 5th and 7th harmonic components are high. With the right tuning of the filters, better performance in conjunction with harmonics can be provided.
Figure 3-34: SVC Norton equivalent – Frequency-dependent impedance (amplitude) and current source (amplitude) for operating points at constant firing angle (110°) and variable network voltage (0.9 pu to 1.1 pu), passive filters tuned to 3\textsuperscript{rd} and 4\textsuperscript{th} harmonic components.

Figure 3-35: SVC Norton equivalent – Frequency-dependent impedance (amplitude) and current source (amplitude) for operating points at constant firing angle (110°) and variable network voltage (0.9 pu to 1.1 pu), passive filters tuned to 5\textsuperscript{th} and 7\textsuperscript{th} harmonic components.
3.7 Conclusions

Section 3 of the deliverable D5.5 presents a detailed description of the most appropriate device-based mitigation solutions, to be implemented with modern PE-based devices. These devices are connected to transmission networks and can worsen the power quality at high-voltage levels, if not properly addressed.

The Section focuses on the problem of harmonic emissions from modern PE-devices. Three types of harmonic are considered –harmonic due to the nonlinear characteristic of the PE-device, harmonic due to the controller operation of the PE-device and switching harmonics that are produced by the switching of the semiconductor switches. For each type of harmonic, specific mitigation approach is presented.

The proposed mitigation solutions have been implemented on the EMT models that have been developed within DP 5.5. The existing models have been upgraded with the following enhancements: With Statcom device, the self-compensation harmonic mitigation solution has been implemented. Several harmonic control loops have been added to the existing fundamental component vector controller. As it has been shown in this section, with this added functionality Statcom’s current harmonics emission have decreased significantly. Because self-compensation functionality is a software solution, it should cause almost no increase in investment costs in practical applications. Considering all this, we recommend self-compensation functionality in Statcom applications.

With PV/battery-generation units it has been shown in this section, how different coupling impedances affect the switching harmonics emission of the device. Typically, PV-units are connected to the network through a simple first-order inductive filter (L-filter) that represents very low investment costs. The filtering performance of such a filter are limited and in many practical applications unsatisfactory. With a more complex second-order or even third-order (LCL-filter) filter much better filtering characteristics are achieved, however designing such a filter is more demanding and also more expensive. In the section, design approach for a LCL-filter has been shown and results compared with L-filter and high-pass filter. It can be concluded that the price/performance ratio is best, when PV-units are interfaced to the network with LCL-filters.

Static Var Compensator (SVC) or more precisely its TCR device is a major source of harmonic emissions, thus designing proper passive filters in SVC is of great importance for proper operation of the device. In this section, procedure for selection of proper tuning frequencies of passive filters has been explained. We have noted that SVC design is always case-by-case problem. Very important task in this design is impedance-frequency analysis at the PCC. Namely, connection of passive filters to the network introduces several resonant points, and it is very important to ensure that the resonant point do not align with the harmonics present in the network. As it has been shown in the section, proper passive filter design can substantially reduce harmonic emissions of a SVC.
Finally, it can be concluded that with device-based mitigation solutions presented in this chapter important reductions of harmonic current emissions levels of several PE-device types can be achieved, however the effect differs largely between different devices and also the cost associated with the implementation of some methods in practical applications could be high and thus not feasible. Implementation of mitigation methods for some devices require a case-by-case approach and thus no generic recommendations can be given in these cases. However, study show that for some devices (e.g. self-compensation with active converters) improvements are possible and can be implemented with reasonable additional costs.
4 System-Wise Mitigation of Harmonic Distortion

4.1 Motivation

With the progressive decommissioning of fossil fuels based synchronous power plants and the ever-growing demands for power systems, the implementation and integration of renewable generations has attracted more and more attention during the past decades. These renewable energy sources, on the one hand, have stimulated and promoted the development of economic and environmentally friendly power systems significantly. However, on the other hand, due to the stochastic and intermittent nature of renewable generation and the power quality (PQ) issues introduced by electronic interfaced devices, the rapid integration of renewable generation could also endanger the stability and security of system operation. In addition, with the rapid improvement to residential living quality and the acceleration of the electrification process, the emergence of new types of household appliance has put forward higher requirements for power quality. Therefore, the potential economic losses caused by power quality issues make the mitigation of power quality problems in renewable generation become one of the most important and popular topics in the field of electrical engineering and academic research.

Harmonic distortion is an important aspect of PQ phenomena. It is usually defined as a sinusoidal voltage or current waveform with frequencies that are integer multiples of the fundamental frequency [78]. The main causes of harmonics distortion are non-linear loads and devices supplied with switch-mode power supplies, and more recently from power electronic (PE) interfaced generators. It is also worth mentioning that “traditional devices” like power transformers are also contributing to harmonic distortions in the network, though to a lesser extent than power electronics interfaced generators, loads, HVDC lines and FACTS devices. The combination of all of these devices is certainly contributing to growing concerns about harmonic distortion in power transmission networks.

With the current trend of applying more renewable energy in power generation, the presence of distributed generation (DG) units is significantly increased in contemporary power systems. DG is mainly based on the advanced technology of power conversion. It introduces harmonic phenomena into the grids. As mentioned earlier in the introduction, the harmonic phenomena may result in thermal stress of insulation, interferences to communication infrastructure, increased power losses, mal-function of switchgears and devices [3], etc. Furthermore, the harmonic phenomena may propagate to other parts of the network or develop into more severe resonance conditions.

The landscape of harmonic phenomena changes as nowadays the harmonics are more widely distributed in the grids, while traditionally the main harmonic injection comes from non-linear loads that are usually related to heavy industries. With increased and widely distributed harmonic injection sources, regulatory bodies have acknowledged the importance of harmonic performance improvement, and a number of standards have specified the required harmonic performance, e.g., IEEE 519 [9]. At the same time, distribution and transmission networks face great challenges in operation and management. They could face heavy penalties if their network sections violate the thresholds specified by the corresponding regulatory body. To prevent avoidable financial losses, network operation should make sure that the harmonic performance in the network is always under the critical, typically standard specified, thresholds.
Apart from pressures from regulatory bodies, utilities may have customers who have equipment that is more sensitive to harmonic phenomena (and/or the resonance conditions caused by the propagation of harmonic phenomena) than others. Some of the customers are even willing to pay more to utilities in order to receive higher harmonic performance than that given by the regulatory body. Considering the fact that the same types of customer usually gather together in a certain area, e.g., residential, commercial and industrial areas, customers' requirement of harmonic performance can and might be needed to be addressed zonally. It may not be necessary to exceed acceptable (by customers) harmonic performance in certain areas where customers do not have a strict requirement of it. In this way, the harmonic performance can be adjusted/tailored to actual need, and the use of extra resources/investment to improve non-required harmonic performance is avoided. The mitigation can be implemented in a way that all customers' requirements are met to certain extents, and the adverse impacts of harmonic phenomena on grids and end-users are minimized. In fact, this concept of having differentiated qualities of electricity supply was initialized in 1989 [28]. It has been addressed for certain customer attributes [24,26] and in some specific areas like reliability options [32]. However, it has not been addressed much in the area of power quality or in harmonic mitigation. With the more challenging harmonic issues faced by current and future transmission networks, proper mitigation approaches are urgently needed to take into account the requirements of harmonic performance from various customers.

4.2 The Costs Associated with Harmonics

4.2.1 The Costs at a Glance

The economic operation of power systems can be deteriorated by harmonic distortion through many aspects, for example, increasing equipment failure rates and extra power losses within the system. Therefore, one of the main benefits of harmonic mitigation is to reduce power losses and thereby reducing operational costs. However, harmonic mitigation solutions usually require the installation of extra components or devices such as filters and line chokes [79], which further increase the investment in power systems. The economic assessment of harmonic mitigation can be summarised as the trade-off between financial savings for improving system performance and additional costs for implementing mitigation solutions.

Different harmonic mitigation methodologies (different filters) have been applied in [80] at various locations, including load centre and secondary side of transformers, etc. It is shown that the power losses can be reduced by 3.6% to 7.6% depending on different mitigation solutions and implementation locations. The costs of various harmonic mitigation solutions are introduced in [81], [82]. In [81], a boost converter-type harmonic elimination circuit with a cost of $1,440 per 60 kW is implemented, and it is proven that the system can claim economic benefits after 3.1 years. The costs of line choke, passive and active filter are estimated and compared in [82]. It has been found that the costs of line choke and passive filter are linearly dependent on the rated power of load, while the cost of active filter is not. If a 20 MVA load is considered, then a 3% line choke, passive filter and active filter would cost about $60,000, $400,000 and $1,400,000, respectively [82]. Clearly, the cost of solution may outweigh the costs associated with the problem that it is trying to solve. Therefore, a careful consideration of all costs associated with the mitigation should be considered.
According to the conclusion of [82], the cost of applying harmonic mitigation solutions near the load demand side increases with the rated load power. Considering the large rated power required by the load demand at the transmission level, the implementation of harmonic mitigation at the load centre may become very expensive, resulting in a long pay-back period for investment. Accordingly, the remaining part of this section concentrates on the harmonic mitigation solutions applied to the generation side.

4.2.2 The Costs in Detail

4.2.2.1 Financial Losses due to Harmonics

Harmonics mainly cause three types of additional costs associated with the operation of the equipment, i.e., utilisation of delivered electrical energy. These costs are separately explained below.

Energy loss: Harmonics may result in an unexpected increase in RMS line currents and consequently lead to additional losses in transmission conductors such as cables and transformers [83].

In the long term, the impacts of voltage and current distortions could lead to:

Abnormal operation: Many electrical loads and equipment units require nearly sinusoidal input voltage for qualified performance. A decrease in efficiency of operation compared with its normal condition and malfunction issues may result from harmonics [84].

Premature aging problems: There is a possibility of harmonics accelerating the aging rate of devices and even causing a failure of equipment [85]. In the long run the replacement of damaged or prematurely aged devices should be taken into consideration [86].

Therefore, financial cost due to harmonics in the power supply system could be calculated as the sum of the costs of three categories:

- Additional energy costs $D_w$
- Premature aging costs $D_a$
- Malfunction costs $D_m$

formulated as:

$$D = D_w + D_a + D_m$$  \hspace{1cm} (4.1)$$

In the following sections, calculation methods of each category are illustrated respectively with reference to [87]–[89]. As for the first two types of cost, either probabilistic or deterministic methods could be used [90]. Deterministic methods would be more appropriate in the case in which appropriate statistical data of system operating conditions and financial-relevant parameters are adequately available, while probabilistic methods are used when the uncertainties of variables are introduced.
4.2.2.2 Deterministic Method to Assess the Costs

4.2.2.2.1 Additional Energy Costs

As for a single electrical component which produces harmonics of voltage or current $G^{h_1}, \ldots, G^{h_{\text{max}}}$ in the time interval $\Delta T$, the corresponding energy loss costs $(D_{w_k})_{\Delta T}$ could be defined as:

$$
(D_{w_k})_{\Delta T} = K_w p_k(G^{h_1}, \ldots, G^{h_{\text{max}}}) \Delta T
$$

(4.2)

where $K_w$ is the unit cost of electrical energy and $P_k(G^{h_1}, \ldots, G^{h_{\text{max}}})$ is the energy loss caused by the harmonics $G^{h_1}, \ldots, G^{h_{\text{max}}}$ of $k$-th component. $h_1, h_2, \ldots, h_{\text{max}}$ are the harmonic orders.

The yearly energy loss cost due to the harmonics of each component $(D_{w_k})_n$ is the sum of costs during every time interval present in the year $n$. Therefore the total loss costs of the entire system in the observed year $(D_w)_n$ could be derived by adding up the yearly cost of all $m$ components.

$$
(D_w)_n = \sum_{k=1}^{m} (D_{w_k})_n
$$

(4.3)

In order to obtain an expected value of energy loss costs over the years of expected life of the electrical power system, it is assumed that the electrical energy unit cost in a generic year $n$ is:

$$
(K_w)_n = (K_w)_1(1 + \beta)^{n-1}
$$

(4.4)

and the present-worth value of the loss costs as:

$$
(D_w)_{n,pw} = \frac{(D_w)_n}{(1 + \alpha)^{n-1}}
$$

(4.5)

where $\beta$ is the variation rate of the unit cost of energy loss and $\alpha$ is the discount rate.

Thus, the present-worth value of the total additional energy loss costs of the whole system during the period of $N_T$ years, is:

$$
D_w = \sum_{n=1}^{N_T} (D_w)_{n,pw} = \sum_{n=1}^{N_T} \frac{(D_w)_n}{(1 + \alpha)^{n-1}}
$$

(4.6)

4.2.2.2.2 Premature Aging Costs

Equation (4.7) shows that the aging costs of $k$-th component $(D_{a_k})_{pw}$ are the difference between investment costs for buying component replacements during the entire period of system life under nonsinusoidal and sinusoidal system conditions.

$$
(D_{a_k})_{pw} = (C_{k,ns})_{pw} - (C_{k,s})_{pw}
$$

(4.7)
\((C_{k,n})_{pv}\) and \((C_{k,s})_{pv}\) could either be measured by the number of replacements during an observation period of the system life or successive fractional losses of life until the component fails. The latter is relevant to mainly electrical and thermal stresses.

Assuming that during a time period \(T_c\), the \(k\) th component experiences \(q\) operating conditions, each of which has corresponding temperature \(\theta_{i,k}\), voltage level \(E_{i,k}\) and duration \(t_{i,k}\). In this case, the total fractional loss of life \((\Delta L_k)_{T_c}\) of the component is the sum of \(q\) fractional loss of life under different circumstances.

\[
(\Delta L_k)_{T_c} = \sum_{i=1}^{q} \left[ \frac{t_{i,k}}{\Lambda(E_{i,k}, \theta_{i,k})} \right]
\]  

(4.8)

In equation ((4.8)), \(\Lambda(E_{i,k}, \theta_{i,k})\) is the useful life of the component when temperature \(\theta_{i,k}\) and voltage level \(E_{i,k}\) are continuously applied. A simple electro-thermal stress model for calculating \(\Lambda\) is recommended by [91]. It is given by:

\[
\Lambda = \Lambda_0 K_p^{-n_p} \exp(-Bc\theta)
\]  

(4.9)

where

\[
K_p = \frac{V_p}{V_{1p}}, c\theta = \frac{1}{\theta_0} - \frac{1}{\theta}
\]  

(4.10)

In equation ((4.9)), \(\Lambda_0\) is the reference life at nominal sinusoidal voltage and reference temperature, \(K_p\) is the peak factor of voltage waveform, \(V_p\) is the peak value of the distorted voltage, \(V_{1p}\) is the peak value of the fundamental voltage, \(n_p\) is the coefficient related to the peak of the distorted voltage waveform, \(B\) is a model parameter proportional to activation energy of the predominant thermal degradation reaction, \(c\theta\) is a parameter to describe the thermal stress, \(\theta_0\) is a reference temperature and \(\theta\) is absolute temperature.

Once the aging costs of a single component are derived using equation ((4.7)), the present-worth value of premature aging costs in the entire system could be computed as follows:

\[
D_a = \sum_{k=1}^{m} (D_{a_k})_{pv}
\]  

(4.11)

4.2.2.3 Probabilistic Method to Assess the Costs

Variables are introduced in voltage or current harmonics when the probabilistic method is used. Consequently, total financial losses due to harmonics \(D\) become a probabilistic quantity and its expected value \(E(D)\) is here calculated by:

\[
E(D) = E(D_w) + E(D_a) + E(D_m)
\]  

(4.12)
4.2.2.3.1 Additional Energy Costs

Starting with the case of a single component subject to a single harmonic \( G^h \) during a period \( \Delta T \). Referring to equation (4.2), the additional energy loss costs of the \( k \)th component \( (D_{WK})_{AT} \) are:

\[
(D_{WK})_{AT} = K_w P_k (G^h) \Delta T
\]  
(4.13)

Since the harmonic \( G^h \) is probabilistic in nature, the expected value of the energy loss of a single component \( E\left[(D_{WK})_{AT}\right] \) would be:

\[
E\left[(D_{WK})_{AT}\right] = K_w \Delta T \int_0^\infty P_k (G^h) f_{G^h} dG^h
\]  
(4.14)

where \( f_{G^h} \) is the Probabilistic Density Function (PDF) of \( G^h \).

Hence, if the component has harmonics \( G^h_1,\ldots,G^h_{\text{max}} \), its corresponding expected value of energy loss costs in the \( j \)th time period of the year \( n \) can be expressed as:

\[
E\left[(D_{WK})_{AT,j,n}\right] = K_w \Delta T_{j,n} \int_0^\infty \int_0^\infty \cdots \int_0^\infty P_k (G^{h_1},\ldots,G^{h_{\text{max}}}) f_{G^{h_1},\ldots,G^{h_{\text{max}}}} dG^{h_1} \cdots dG^{h_{\text{max}}}
\]  
(4.15)

where \( f_{G^{h_1},\ldots,G^{h_{\text{max}}}} \) is the joint PDF of \( G^{h_1},\ldots,G^{h_{\text{max}}} \).

Similar to the deterministic method, by adding up all the expected loss costs subjected to the component in different time intervals during the year \( n \), the yearly loss costs \( E(D_{WK})_n \) of \( k \)th component can be computed. Finally, the expected present-worth value of total energy loss costs arising in the whole system due to harmonics in the period of \( N_T \) years \( E(D_w) \) could therefore be formulated as:

\[
E(D_w) = \sum_{n=1}^{N_T} E(D_{WK})_{n,\text{pw}} = \sum_{n=1}^{N_T} \frac{E(D_w)_n}{(1+\alpha)^{n-1}} = \sum_{n=1}^{N_T} \sum_{k=1}^{m} \frac{E(D_{WK})_n}{(1+\alpha)^{n-1}}
\]  
(4.16)

where \( \beta \) is the variation rate of the unit cost of energy loss and \( \alpha \) is the discount rate.

4.2.2.3.2 Premature Aging Costs

For the \( k \)th component in the system, its expected present-worth value of aging costs can be calculated using equation (4.17), where \( E(C_{WK,\text{pv}}) \) and \( E(C_{WK,\text{pw}}) \) are the expected present-worth values of investment costs for buying components along the period of system life under nonsinusoidal and sinusoidal operating conditions respectively.
So, the expected value of aging costs in the entire system is the sum of $E(D_{a_k})_{pv}$ of each component, expressed as:

$$E(D_{a_k})_{pv} = E(C_{k,ns})_{pv} - E(C_{k,a})_{pv}$$

(4.17)

$$E(D_a) = \sum_{k=1}^{n} E(D_{a_k})_{pv}$$

(4.18)

In order to evaluate $E(C_{k,ns})_{pv}$ and $E(C_{k,a})_{pv}$, the expected value of relative fractional loss of component life should be estimated. Assuming that the useful life of a single component depends on $g$ variables, then the expected value of fractional loss of life $E(\Delta L_{k})_{\Delta T_{jn}}$ during the $j$th time interval in the year $n$ can be formulated as (4.16), where $f^{\Delta T_{jn}}_{x_{1,k},x_{2,k},\ldots,x_{g,k}}$ is the joint probability distribution function (PDF) of the variables in the observation interval.

$$E(\Delta L_{k})_{\Delta T_{jn}} = \Delta T_{jn}^{\ast} \int_{0}^{\Delta T_{jn}} \int_{0}^{\Delta T_{jn}} \ldots \int_{0}^{\Delta T_{jn}} f^{\Delta T_{jn}}_{x_{1,k},x_{2,k},\ldots,x_{g,k}} \prod_{i=1}^{g} dx_{i,k}$$

(4.19)

Using equation (4.10), the electro-thermal life model $\Lambda(K_{p},\theta_{k})$ is applied and equation (4.19) is simplified to be:

$$E(\Delta L_{k})_{\Delta T_{jn}} = \Delta T_{jn}^{\ast} \int_{\theta_{k}}^{\theta_{k}} \int_{D_{\theta}}^{D_{\theta}} f^{\Delta T_{jn}}_{K_{p},\theta_{k}} \Lambda(K_{p},\theta_{k}) dK_{p} d\theta$$

(4.20)

in which $f^{\Delta T_{jn}}_{K_{p},\theta_{k}}$ is the joint PDF of voltage peak factor $K_{p}$ and temperature $\theta$ (i.e. influence factor variables) defined in the time interval $\Delta T_{jn}$, $D_{\theta}$ and $D_{K_{p}}$ are variation domains of the variables.

4.2.2.4 Malfunction Cost

Calculation of a malfunction cost is the most complex subject among the three costs and the one which needs more exploration. The absence of evidence for the cause-effect relations between harmonics and the degradation of device performance, as well as the difficulty of using a single index to evaluate the physical consequences of malfunction, are challenges for researchers [89]. To calculate the financial costs of malfunctions resulting from harmonics, the following must be known [92]:

- Clear classification of levels of performance degradation for different types of equipment
- Corresponding quantitative indices to indicate device performance in different perspectives
- Evaluation of the cost of each detrimental effect
- Methods that can discriminate harmonics from other power quality phenomena while evaluating the loss of performance
Currently there are no common agreements on the way to convert the knowledge above into actual data or parameters for a systematic analysis. In [93], a unified index is defined to compute the cost related to power quality issues and the malfunctions due to harmonics are considered as interruptions when THD of the system is over 20%. The method proposed in [94] is applied to a Weibull distribution probability model to represent the occurrence of malfunctions which are here simply translated as component failures with a trigger condition as 5% of THD of bus voltage at PCC for utilities below 69 kV.

4.2.3 Economic Assessment of Harmonic Mitigation Devices

Harmonic problems are no longer limited in power distribution networks because of the proliferation of energy-sufficient but harmonic-producing power electronics applied in high-voltage networks [95]. The following components can be some of the direct causes of harmonics in transmission networks [96]:

4.2.3.1 Flexible AC Transmission System (FACTS) Devices

FACTS devices such as Static Var Compensator (SVC) use thyristor switched capacitors and thyristor controlled reactors to provide reactive power when needed and absorb it when generated [97]. They are popular options for solving power quality issues but create harmonics in the output signal of the system [98].

Wind power plant: In some of the wind turbine generators, their rotors are connected to the grid via power converters which are nonlinear devices that induce harmonic currents [95].

Variable Frequency Drives (VFD): VFD is typically used to control the speed and torque of an AC motor by varying the frequency and voltage supplied to it [99]. Harmonics induced by VFD relate to the design of the drive system and can be reduced by using external filtering [100].

High Voltage Direct Current (HVDC) links: HVDC systems converters inject harmonics and cause resonance problems at some frequencies [101].

Electric arc furnaces (EAF): The harmonic problems caused by EAF during steel production have always been taken seriously and widely studied [102].

The solutions to harmonic mitigation take on great significance as the financial loss is considerable [103]. Depending on the design of harmonic sources and the requirements on the output signal of the system, there are different harmonic mitigation strategies and techniques.

Some of the harmonics problems could be solved by dedicated design during the planning stage, such as configuring the primary side of the substation transformer into a delta or ungrounded wye connection to help prevent the propagation of zero-sequence harmonics [104], keeping the amount...
of nonlinear loads less than 30% of the maximum transformer’s capacity [96]. Some could be solved using existing equipment such as moving loads between branch circuits or adding additional circuits to isolate sensitive devices from harmonic sources and fixing poor grounding on an individual device or facility as a whole [105].

Another option for removing or reducing harmonic impacts is to install the following devices:

**Line reactors:** A line reactor is a 3-phase series inductance connected to the line side of Variable Speed Drive (VSD), intended to help attenuate harmonics and to prevent VSF from possible tripping on over-voltage via absorbing oscillatory transients [104]. Meanwhile, due to being inductive they also cause a voltage drop, which increases with the frequency [106].

**12-pulse rectifier solution:** A 12-pulse rectifier is one of the high pulse rectifier solutions, consisting of two 6-pulse diode bridges together with a 30° phase shifting transformer [107]. This configuration allows 5th and 7th harmonics from the first converter to cancel those of the second while the 11th harmonic becomes dominant [106]. With a price that is reasonably cheap though a lot more expensive than line reactors, the 12-pulse rectifier solution is able to reduce the total current harmonic distortion (THDi) down to 10% and to provide extra input protection for harmonic source [108].

**Passive filters:** Passive filters are conventionally formed of a passive circuit consisting of an inductor, a capacitor and an electrical resistance [109]. They are state-of-the-art devices that have been widely applied both, in existing electric power systems and during design phase. The uncertainties and risks regarding power quality issues can be covered by them [110]. The use of passive filters however, has some drawbacks such as the bulky size of components due to the low order harmonics to suppress, risk of resonance problems which reduce the system stability and high dependence of filter configuration on power system connected to [111].

**Active filters:** The basic principle of active filters is to use power electronics to cancel out harmonic currents or voltages by producing corresponding (but opposite in phase) current or voltage components [112]. Unlike passive filters, their performance is independent of the system they are connected to and they do not contribute to any resonance problems. More attention is increasingly attracted by active filters since the prices of IGBTs (Insulated gate bipolar transistors) and DSPs (digital signal processors) are currently reduced to a reasonable level making active filters less expensive than they used to be [113]. One major disadvantage is that the capacity of active filters must be no smaller than the nonlinear load to be filtered, which makes it financially unfeasible for some large projects [114].

**K-factor transformers:** K factor rated transformers are sized appropriately to handle the temperature rise induced by current harmonics in transformer windings and the K factor refers to a constant describing the capability of the transformer to supply the nonlinear load, while remaining at operation temperature within limit, as a multiple of the normal eddy current losses [108]. This technique
increases protection for transformer and VSD connected to it from line transients but it neither improves power quality nor increases the energy efficiency of the system.

In [96], [106], [107], [110] comparisons between ways to eliminate harmonics have been conducted as indicative guidelines and the above (section 4.2.3.1) are described as the most common methods for harmonic mitigation in low voltage to medium voltage networks.

A score-based comparison is provided in [115], shown in Table 4-1. It can be seen that the line reactor solution is the simplest and also cheapest way for application; the 12-pulse rectifier solution has the highest energy efficiency but the highest complexity in terms of operation and installation; the Passive filter achieves relatively high scores in every aspect; and the Active filter provides good harmonic mitigation but poor value for money.

Table 4-1: Comparison of harmonic mitigation approaches [115]

<table>
<thead>
<tr>
<th></th>
<th>Line reactor</th>
<th>12-pulse rectifier solution</th>
<th>Passive filter</th>
<th>Active filter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Harmonic mitigation (THDi)</td>
<td>30-48% Rating = 1.0</td>
<td>6-15% * Rating = 3.0</td>
<td>5-16% ** Rating = 4.0</td>
<td>3-20% ** Rating = 5.0</td>
</tr>
<tr>
<td>Energy efficiency</td>
<td>96-97% Rating = 4.0</td>
<td>97-98% Rating = 5.0</td>
<td>95.5-96.5% *** Rating = 4.0</td>
<td>95-96.5% *** Rating = 3.0</td>
</tr>
<tr>
<td>Overall space required</td>
<td>Rating = 5.0 Rating = 3.5</td>
<td>Rating = 3.0</td>
<td>Rating = 2.5</td>
<td></td>
</tr>
<tr>
<td>Overall simplicity</td>
<td>Rating = 5.0 Rating = 2.5</td>
<td>Rating = 4.0</td>
<td>Rating = 2.5</td>
<td></td>
</tr>
<tr>
<td>Overprice performance</td>
<td>Rating = 5.0 Rating = 4.0</td>
<td>Rating = 3.0</td>
<td>Rating = 2.5</td>
<td></td>
</tr>
</tbody>
</table>

* View on the medium voltage side  
** Compensation rate depending on the settings and sizing  
*** Efficiency depending on compensation rate

Hybrid harmonic mitigation techniques are also being studied to coordinate the advantages of both methods [106]. Despite the generic comparison above, actual practice largely depends on the aim of the application and budget of the equipment as some of the main factors for choosing the appropriate solution. To compute the financial cost of harmonic mitigation $C$, the following costs should be taken into account:

- Investment costs of the device $C_F$
- Costs for energy losses of the device $C_E$
- Costs for operation and maintenance $C_M$
which could be formulated as:

\[ C = C_F + C_E + C_M \]  \hspace{1cm} (4.21)

The costs of the harmonic mitigation techniques utilised in electric transmission networks vary largely from project to project due to the particular objective-oriented design and overall complexity of the application. Currently, relevant statistical cost data is lacking in the literature so the economic assessment methods and data for harmonic mitigation techniques in distribution networks are provided for reference.

The investment costs, capital costs \([107]\) or total installation cost \([108]\) all refer to the amount of money spent on manufacturing equipment. Due to the structural simplicity of line reactors and passive filters compared to other harmonic mitigation techniques, their investment costs can be regarded as the sum of the expense of capacitors, resistors and inductors. This straightforward calculation method has been widely used as one of the optimisation objective functions for the design of filter schemes in many papers and by referring to \([101], [106], [109], [110], [111]\), the calculation formula could be summarised as:

\[
C_{F,PF} = \sum_{i=1}^{N} K_C Q_{C,i} + \sum_{i=1}^{N} K_R P_{R,i} + \sum_{i=1}^{N} K_L
\]  \hspace{1cm} (4.22)

where \(K_C (\$/kvar)\), \(K_R (\$/kW)\), \(K_L (\$/kvar)\) are the unit costs of capacitors, resistors and inductors respectively, \(Q_{C,i}\) and \(Q_{L,i}\) represent the amount of capacitance and inductance in kvar of the \(i\)th branch, \(P_{R,i}\) is the total real power of the \(i\)th branch and \(N\) is the number of filter branches of the entire application.

Table 4-2 shows one of the price models of passive filter components and there are some others available in \([121], [122], [123]\). As for other solutions for harmonic mitigation, there are a lot more factors in terms of product configuration that influence the investment costs \([124]\) which means cost is mostly discussed and described using generic indication but not actual numbers \([125]\).

Table 4-3 shows approximate prices of these techniques with various capacities.

As indicated in Table 4-1, energy losses of harmonic mitigation techniques are inevitable. Though configurations of the techniques mentioned above are different, the costs for the energy losses \(C_E\) of each technique can be calculated using equation (4.6) in the first section.

The costs of operation and maintenance include the costs of services for different operation conditions during the lifetime of the equipment. In \([117]\), the continuous maintenance costs of passive filters incurred every year are assumed to be 5% of investment costs. In \([93]\) maintenance costs of various power quality solutions are considered as a whole and are determined as 20% of annual hardware cost.
Table 4-2: Estimated costs of components of passive filters [104].

<table>
<thead>
<tr>
<th>Capacitors</th>
<th>Rated voltage</th>
<th>&lt; 1kV</th>
<th>1 kV to 10 kV</th>
<th>10 kV to 25 kV</th>
<th>25 kV to 50 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost</td>
<td></td>
<td>$15/kvar</td>
<td>$20/kvar</td>
<td>$40/kvar</td>
<td>$65/kvar</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Inductors</th>
<th>Rated voltage</th>
<th>1 kV to 10 kV</th>
<th>10 kV to 25 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated current</td>
<td>&lt; 100A</td>
<td>$1400</td>
<td>$2800</td>
</tr>
<tr>
<td></td>
<td>100A to 500A</td>
<td>$1700</td>
<td>$3400</td>
</tr>
<tr>
<td></td>
<td>500A to 1000A</td>
<td>$1900</td>
<td>$3800</td>
</tr>
</tbody>
</table>

Table 4-3: Approximate cost of different harmonic mitigation techniques [106].

<table>
<thead>
<tr>
<th>Harmonic mitigation techniques</th>
<th>Rated capacity</th>
<th>20HP*</th>
<th>100HP*</th>
<th>400HP*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactor (5%)</td>
<td></td>
<td>$520</td>
<td>$1100</td>
<td>$3800</td>
</tr>
<tr>
<td>K-factor (13) transformer</td>
<td></td>
<td>$5300</td>
<td>$11000</td>
<td>n/a</td>
</tr>
<tr>
<td>Tuned passive filter</td>
<td></td>
<td>$2800</td>
<td>$3900</td>
<td>$7000</td>
</tr>
<tr>
<td>Low pass filter</td>
<td></td>
<td>$2400</td>
<td>$5600</td>
<td>$13000</td>
</tr>
<tr>
<td>Active filter</td>
<td></td>
<td>n/a</td>
<td>$27000</td>
<td>$65000</td>
</tr>
</tbody>
</table>

*HP: horsepower

4.3 Optimisation Based Harmonic Mitigation

Coordinated mitigation of harmonics by means of optimisation methods in transmission systems with a large penetration of Renewable Energy Sources (RES) has not been discussed in previous literature on the general subject of PQ in power systems, i.e., no reference was found on the exact topic. The subject though, has been studied for application to Distribution Networks (DNs), since the spread of RES (wind and PV plants) connected directly to DNs as DG has been occurring more frequently in the past, something that is evidenced by the number of research papers reviewed and collected for this report (from 2009 onwards).

Therefore, the bulk of the references reported in this document deal with the subject as the optimal sizing and location of DG (mainly of the wind and PV RES types) in DNs so that their PQ is kept to
standards. A portion of these approaches consider, in addition, the extra deployment of corrective measures for harmonic mitigation such as filters and FACTS devices. Wind and PV plants belong to the type of Inverter Based DG (IBDG) and the main concern with their spread is the amount of harmonic injection to the DN, however they can also help with the harmonic mitigation if properly planned and installed along with some other corrective measures. Conventional DGs types are also commonly included in these studies, hence normally the reported references deal with the complete mix of DG that can be connected to the DNs, though the main problem with the latter is the variation in the short circuit currents and their impact on the protection of distribution feeders.

The reason behind optimising the location of the DG in the DNs is that their deployment could be planned optimally and in this way it can improve network behaviour. One common focus is the reduction of active losses caused by the spread of DGs close to the final loads, being a common parameter to be minimised in the Objective Functions (OFs) of the proposed optimisation methodologies. Hence, most of the methods have in general two focuses or general optimisation objectives: reduction of losses and assurance of minimum acceptable PQ (reduction of impact on short circuit currents and protection to a lesser degree). With respect to PQ, which is the feature of interest of this report, it is usually quantified/measured mainly by the THD, Individual Harmonic Distortion (IHD) and voltage quality (voltage sag and voltage deviation). These parameters are either included directly in the OFs of the respective optimisation procedures or as constraints.

In general, the OFs are usually a function of the costs associated with the DG equipment to deploy, cost of losses, reduction of PQ related costs, and cost of corrective measures for improvement of PQ, such as Passive Power Filters (PPF), Active Power Filters (APF), FACTS devices (STATCOMs, UPFCs), etc. All these aspects, if occurring more than once in the OF, are included with weighing or penalty factors (or penalty functions), or, in other cases, by separated OFs, resulting in multi-objective optimisation methodologies.

With respect to the method of solving the optimisation problem, it is evidenced that three metaheuristic optimisation techniques are favoured by large, namely Genetic Algorithms, Particle Swarm Optimisation (PSO), and Differential Evolution (DE), in that order, leaving classical or strict optimisation approaches for cases in which a more complete model of the dispatch problem is included in the proposed methodology. Another common feature of the reported references is that authors compare different algorithms for solving the optimisation problems in their proposals, in order to validate that the option chosen was the best. This happens in cases where the option chosen is a metaheuristic approach, which is in the majority of cases. Mostly the advantages of one method with respect to another are not great and the use of the metaheuristic approach chosen is due to the slightly better results obtained for the specific study cases analysed in the papers, in addition to their simplicity.

Most of the references calculate the indicators of PQ with respect to reference values given in the IEEE Standard 519, some others employ the local standards of their respective countries.
The DN test systems used in the papers to demonstrate the validity of their proposals are almost always radial. Hence the improvement in PQ by means of DG installation or corrective measures deployment are “feeder oriented”. However, it is believed that most of the methods could be extended to application to transmission networks. This is particularly the case with the group of references that deal with the problem in a market-based way, since the optimisation procedure includes classic optimal dispatch in a similar manner to that commonly studied in transmission networks.

It remains unknown as to why the deployment of corrective measures for harmonics mitigation has not been studied for application to transmission networks. One reason may be the more extensive computation times that would be associated with larger transmission networks, including the conventional generation dispatch problem, and additional complications if Unit Commitment (UC) is to be considered, making optimisation approaches not efficient for these cases. Further discussion on mitigation options is provided in Appendix B.

4.4 Optimization Framework for Harmonic Mitigation in Transmission Networks

Harmonic mitigation, considered as an optimization problem, can be tackled by following the optimization framework which was proposed under this project as provided in Figure 4-1. Once the critical issues are identified, the objective function to be optimized can be designed to address the concern and optimization purpose. Then the potential solutions can be investigated and included in the solution pool for later optimization. An appropriate optimization methodology can then be used to minimize the objective function by choosing the optimal solutions from the solution pool. The obtained optimal mitigation strategy then will be evaluated to see whether it would cause any other issues in network operation before it is taken as the final optimal solution.

4.4.1 Problem Description and the Definition of Objective Functions

Harmonic performance can be improved globally or zonally across the whole network depending on the purpose of optimization. In literature, THD [126] is widely used for assessing the harmonic distortion. THD is assessed based on 95th percentile value. The harmonic performance at all buses can be aggregated and used as the objective function for optimization. The optimization objective function can be designed in a way to reflect the effect of the mitigation scheme on the harmonic performance and assess how far away the received harmonic performance is from the thresholds set by regulation.
4.4.1.1 Global Harmonic Mitigation

For global harmonic mitigation, one can assume the THD threshold is denoted as $THD_{TH}$. Given the performance index and specified thresholds, the objective function can be defined as the gap between two of them if the harmonic performance received by end users is worse than the constraint/thresholds, as given by the Global Harmonic Gap Index ($GHGI$), which is defined as equation (4.23).

$$GHGI = \sum_{j=1}^{B} |THD_j - THD_{TH}|_{THD_j > THD_{TH}}$$

(4.23)

where $B$ is the total number of buses in the network; and $j$ is the bus index.

4.4.1.2 Differentiated Zonal Harmonic Mitigation

The requirement on harmonic performance could vary from area to area. To provide the services zonally, the zonal harmonic performance requirements should be determined before defining the objective function. The zones can be obtained by the nature of customers connected to the grid, and in general the area can be labelled as residential, commercial or industrial areas. If needed, the grid can even be divided into more detailed/smaller areas depending on the trade-off between mitigation efficiency and the level of area division [127]. Once the zone division is obtained, the corresponding harmonic performance thresholds can be determined by the percentage of customers whose requirements on harmonic performance have been fulfilled. References [127]-[134] provide the detailed approach of a demarcating grid into zones. Figure 4-2 gives the three steps that can be used to obtain the zonal division and zonal harmonic performance thresholds.
Figure 4-2: Flowchart of zone division [127].

With the obtained zones and defined zonal harmonic performance thresholds, the objective function can be defined by aggregating the gaps between the actual THD and zonal thresholds in different areas, and forming the total harmonic performance index, named as Zonal Harmonic Gap Index (ZHGI), as defined in equation (4.24).

\[
ZHGI = \sum_{i=1}^{N} \left( \sum_{j=1}^{B_i} \left| \text{THD}_{ij} - \text{THD}_{TH,i} \right|_{\text{THD}_{ij} > \text{THD}_{TH,i}} \right)
\]  

Differentiated zonal harmonic mitigation can be converted to a global optimization problem by considering the whole grid as one area. The optimization procedures are the same for these two types of problem, except for the number of zones. Between these two problems, zonal mitigation is more complicated as it aims at providing more detailed customer-tailored services.

4.4.2 Determination of Potential Mitigation Schemes

Various mitigation schemes have been explored to provide sufficient/required harmonic performance, from equipment level to network level. As for the equipment/device level, the harmonic injection devices (such as converters etc.) can be improved by re-programming or design such that the harmonic injection by the harmonic sources can be reduced. These can be considered as potential and feasible mitigation approaches due to the flexibility and controllability of the advanced power electronic devices today. Apart from that, passive filters (PF) are usually considered as potential mitigation solutions at transmission level considering both their relatively lower cost than other
devices and the high power rating, which is required in transmission networks. They are widely used for mitigation purposes by industries and utilities, with the benefit of cost-effectiveness. By connecting the PF at critical locations in the grid, the overall harmonic performance at the network level can be improved. As for potential locations for placing the PF, they can be selected globally and zonally based on the analysis of the harmonic performance and sensitivity of the planned filter installation to the mitigation effect. Furthermore, the critical locations connected with at least four power lines are also preliminarily made available for passive filter placement (step 4 in Figure 4-3), as it is believed the filter placed at the branch interaction can stop the propagation of harmonic phenomena from one area to others. After these locations are selected, they can be fed to the optimizer to search for the optimal filter placement.

4.4.2.1 Global PF placement

The buses are ranked based on the severity of harmonic phenomena (THD) in descending order (as given in step 1 in Figure 4-3). For instance, if bus Bi has the highest THD, its rank is 1, RTHD(Bi)=1. Then the location at bus Bi is initialized for PF placement (step 2 in Figure 4-3). When the PF is preliminarily installed at the selected location, the rest of the buses are ranked again based on newly evaluated THDs, and then the bus which has the most severe THD, after placing the previous selected filter, is selected and included in the mitigation strategy (step 3 in Figure 4-3). The aforementioned procedure of ranking and location selection is repeated until reaching the pre-defined maximum number.

4.4.2.2 Zonal filter placement

To make sure the potential PF placement also facilitates the zonal harmonic performance provision, the PF placement should also be selected zonally. The steps used to select the zonal filter placements are the same as that for the global filter placement, except that in such cases the bus ranking is based on zones rather than the whole grid (step 5 in Figure 4-3). In selecting the location for PF placement, the feasibility in terms of geography and transportation should be considered as well.
1) Rank all buses according to THD; obtain $R_{THD}$ for each bus $B_i$

2) $U_G = U_G \cup \{PF \text{ and location of bus having } R_{THD} = 1\}$

3) Place PF then perform steps 1 and 2, repeat this until reaching the pre-defined number of filters

4) $U_G = U_G \cup \{PF \text{ and location of intersections of branches}\}$

5) For each zone $Z_i$, $i = 1, \ldots, N$, set potential zonal device set $U_{z_i} = \emptyset$, perform steps 1-4 with bus ranking performed within zone $Z_i$ only

$U_T = U_G \cup U_{z_1} \cup \ldots \cup U_{z_N}$

$X = U_T$; $\Gamma = \emptyset$

Figure 4-3: Flowchart of selecting potential filter placement.

### 4.4.3 Greedy Based Optimisation

With the potential solutions selected as above, appropriate optimization approaches can be applied to search for the optimal mitigation strategy. Various conventional and artificial intelligence based optimization approaches have been explored for planning problems, such as evolutionary algorithms [128], heuristic techniques [129], [130] and hybrid approaches etc. Greedy algorithms are applied in solving large-scale optimization problems due to the benefit of their simple implementation and relatively low computational costs [131], [132]. A greedy based approach has shown its superiority in finding a device based mitigation strategy [127]. Figure 4-4 provides the greedy algorithm based optimization procedure, in which the problem is divided into a number of consecutive stages, and at each stage the greedy algorithm is applied to select the best solution under the given operating condition.

At the first stage, a pool of potential solutions selected from Section 4.4.2 is denoted as set $U$. This set consists of the solutions that include the types of the solution and the implementing locations. If there are $MD$ potential solutions selected in Section 4.4.2, and for each solution there are $MI$ possible
ratings, in total there will be a pool of MD×MI potential solutions which consist not only of the locations and types, but also the ratings of the filters. These solutions are initially made available for searching the optimization space. The greedy algorithm is adopted to choose the best solution from set U, as shown in Figure 4-4. The solution which has the minimum assessed objective function at each stage (denoted as s) will be included in the pool of final solutions set Γ.

Figure 4-4: Illustration of optimization process.

After the selection, X will be updated while excluding the previously selected solutions. At the next stage, the previously selected solution will be placed in the network before the next selection. The placement of selected solution results in a different operating condition, and the greedy algorithm is used to search for the best solution at this stage while excluding the previously selected solutions. The procedure of greedy selection repeats until the maximum number of solutions is reached, or the requirement of harmonic performance is met. Finally, the last set of Γ is produced as the final optimal mitigation strategy.

4.4.4 Test Network and Operating Conditions

4.4.4.1 Uncertainties of Operating Conditions

In optimization, the harmonic performance varies depending on the operating conditions, including loading, outputs of distributed generation, network parameters and network topologies etc. However, the operating conditions vary throughout the day, week, month and year. This results in great difficulty in constructing realistic operating conditions in order to provide accurate harmonic performance assessment. A study of the literature shows that the integration of a prior-knowledge of the uncertainties of network behaviour can greatly improve the performance in optimization and
network analysis [134]. Therefore, it is important to address network uncertainties in simulation during the optimization process.

Measurements are important sources of information that can be used to model the operating conditions for network simulations. There are mainly two classes of measurement, real meter measurements and Pseudo-measurements. The former provides more accurate information while the latter is usually obtained by estimation and forecasting approaches which provide relatively less accurate information depending on the reliability of the data sources and the estimation approaches themselves. Distributed generation outputs (renewable generation in particular) can be measured and aggregated (or estimated) based on historical data or realistic output data considering the weather [135]. The loading of different types of customer (including commercial, industrial and residential loads) can be extracted from surveys [136]. A wide range of data for power system modelling and uncertainty analysis are given in [137], which provide actual loading, PV and wind profiles in European counties in the past decade. This can be used to model realistic network operation conditions for optimization.

4.4.4.2 Methodology of Addressing Uncertainties

The uncertainties mentioned above can be addressed in simulation settings in order to construct realistic operating conditions. The scenarios that will be included in simulation can be selected depending on the optimization purpose. For instance, for general harmonic performance assessment, all possible operating scenarios can be included in simulation, for example using Monte Carlo approaches [138]. If the purpose of the optimization is to obtain strict constraint management, the study may focus on the worst operating scenarios in order to diminish constraint violation in actual network operation.

However, in solving optimization problems for large scale power networks, there is usually a constraint regarding computation load, as the optimization process usually requires many iterations before reaching the final optimal strategies. Thus, the Monte Carlo approach is not promising for this application due to the large number of possible operation scenarios existing in the actual network operation. Therefore, in this case, representative operating points can be selected and included in the optimization process. The representative operating points can be sampled/selected based on probabilistic approaches which select the most likely operating conditions in actual operation.

In practice, the patterns of operating conditions repeat in season and year, and there is no need to repeat the similar operating conditions in a network assessment. To reduce the repetition of running similar operating conditions in a harmonic performance assessment, representative operating points can be selected and included in the optimization process. The representative operating points can be selected using clustering techniques [127], [139] which cluster the inputs of data based on their similarity, i.e., the distance between the operating points. The inputs to the clustering approaches may include the loading profiles of different loads and profiles of different types of renewable energy generation. A number of clustering approaches have been explored to select the representative
operating points, such as K-means, fuzzy c-means, agglomerative clustering algorithm and Gaussian mixture distribution algorithm. In [127] K-means with the clustering criterions of Calinski-Harabasz is used to select the representative operating points for power quality optimization. The sets of clusters obtained by various clustering techniques can be validated using Silhouette [140], and the best set can be used to generate the representative operating points (i.e., the centres of the obtained clusters) for the simulation.

4.4.5 Test Network and Selection of Representative Operating Conditions

4.4.5.1 Test Network

The modified IEEE 68-bus test network as given in Figure 4-5 represents a realistic complex meshed transmission network and has been used for various power system studies in the past [135]. The network has five distinct areas interconnected with inter-area tie lines, which is suitable for testing the concept of the system area mapping proposed in the paper. Apart from the 10 synchronous machines in the original network, the model is enhanced to integrate renewable energy generations, e.g., 20 DGs consisting of 10 wind farms modelled as DFIGs and 10 PV plants.

4.4.5.2 Selection of Representative Operating Points (OP)

To address the uncertainty of the operating conditions, in total 8784 OPs with varying loading, PV and wind profiles are obtained from actual renewable generation profiles in Europe in 2016 (https://open-power-system-data.org/):

- The loading profile is obtained from the actual loading in Great Britain (GB) in 2016.
- 10 PV profiles are obtained from the PV outputs from ten different countries in Europe (DE, DK, ES, FR, GB, R, PL, PT, RO, SE).
- 10 wind profiles are obtained from the WF outputs from ten different countries in Europe (DE, DK, ES, FR, GB, R, PL, PT, RO, SE).
These profiles are fed into the clustering algorithm K-means for classification, and 18 clusters are obtained as shown in Figure 4-6, which presents the size of the clusters and appropriateness of the clustering. Positive and higher Silhouette values indicate that the object is well matched to its own cluster but poorly matched to its neighbouring clusters. It can be seen from Figure 4-6 that the majority of OPs have appropriately matched to their clusters. For each cluster, its centre is chosen as the representative operating point of the cluster. Thus, in total 18 OPs are selected for optimization in this case.

Figure 4-5: Modified IEEE 68 bus test network.

Figure 4-6: Silhouette of the obtained clusters.
To further verify the appropriateness of the representative OPs, the cluster which has the largest percentage of negative Silhouette values (i.e., the worst cluster among the 18 clusters) is chosen for further analysis. Thus, cluster 16 with 119 OPs is chosen in the study. In the simulation, 6 iterations are run for each OP, including the representative OP (a single operating point that represents the whole cluster) and all OPs in the chosen cluster. The penetration level of RES is 30% in this analysis.

Figure 4-7 provides the mean THDs obtained from the representative OP (taking six random samples of harmonic generation) and the mean THD obtained based on all OPs (taking $119 \times 6$ random samples of harmonic generation) in the corresponding cluster. It can be seen that the mean obtained from the representative OP has a similar shape to that obtained from all OPs in the corresponding cluster. Figure 4-8 provides the most likely THDs that are obtained from all OPs in the cluster based on probability and PDF analysis. Figure 4-8 also provides the range of THD (bounded by the minimum and maximum value obtained) obtained based on the representative OPs with six iterations. The analysis shows that the THD that is likely obtained by analysing the cluster locate within the range that is obtained by analysing the single representative OP only.

Both Figure 4-7 and Figure 4-8 demonstrate the appropriateness of using the representative OP in the study rather than all OPs in the cluster. This greatly reduces the computation load. Therefore, in the following study, THD assessment is based on 18 representative OPs and 6 iterations/calculation (10 min harmonic sampling) per operating point, in order to include the uncertainty of harmonic injection even for the same operating point that defines the network loading and generation profiles. THD is calculated based on 95 percentile values while different operating points are assigned with different probabilities (weights) based on the actual size of the corresponding clusters.
Figure 4-7: Comparison between the THD obtained based on the representative OP and the corresponding cluster with 6 iterations (THD-A, THD-B and THD-C are the THD obtained from the three phases respectively).

Figure 4-8: Comparison between the mostly likely THD obtained by analysing all OPs in the cluster, and the range of THD obtained by analysing only the representative OP with 6 iterations.
4.4.6 Simulation and Results

4.4.6.1 Selection of Initial Potential Solutions

The pool of solutions which were made available for selection in the optimization process consists of:

1) 14 bus locations for PF placement. The bus locations are chosen based on the rankings of $\Sigma$THD zonally and globally (as introduced in Section 4.4.2, and on the criticality of the buses which are connected with at least 4 power lines, where are the junctions for harmonic propagation. Double tuned filters (250 and 350 Hz) are used as the harmonic injection spectrum from the DG and non-linear loads are mainly dominated by the 5th and 7th harmonic, as shown in Table 4-4. The ratings of PFs that the optimisation process is choosing from are 30, 50, 100, 150, 200 Mvar. If more PF ratings are included in the pool, the calculation load/complexity will increase as well. The reason of choosing these PF ratings for optimization here is to have the trade-off between the computation load/complexity and the precision of PF ratings. Further analysis can be conducted around the selected optimal PF rating if more specific PF rating is needed.

2) 20 locations for harmonic reduction at the source. These locations are selected based on the location of 10 PV plants and 10 wind farms. The scaling factors representing reduction in harmonic (irrespectively of who it could be achieved) by the source are uniform for all harmonic orders. The harmonic reduction ratios considered are 30%, 40% and 50%. Any other scaling factor, including different scaling factors for different plants and different harmonics, could be considered without any loss of generality.
Table 4-4: Examples of harmonic injection at DGs and non-linear loads (x: Ia_h/ Ia_1 %, y: Ib_h/ Ia_1 %, z: Ic_h/Ia_1 %).  

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>DGs</th>
<th>Nonlinear Loads</th>
<th>Sample 1</th>
<th>Sample 2</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>x</td>
<td>y</td>
<td>z</td>
</tr>
<tr>
<td>2</td>
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<td>0</td>
<td>0</td>
</tr>
<tr>
<td>3</td>
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<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>1.6</td>
<td>1.6</td>
<td>1.6</td>
<td>0</td>
</tr>
<tr>
<td>6</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.057</td>
</tr>
<tr>
<td>7</td>
<td>1.16</td>
<td>1.16</td>
<td>1.16</td>
<td>0.336</td>
</tr>
<tr>
<td>8</td>
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</tr>
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</tr>
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</tr>
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</tr>
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</tr>
<tr>
<td>22</td>
<td>0</td>
<td>0</td>
<td>0</td>
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</tr>
<tr>
<td>23</td>
<td>0.1</td>
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<td>25</td>
<td>0.05</td>
<td>0.05</td>
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</tr>
</tbody>
</table>

4.4.6.2 Optimization Results

4.4.6.2.1 Case 1: Zonal Optimization (Two Zones) with Assumed 90% Penetration of RES

The system is divided into two zones: New England & New York. Their THD thresholds are set, for illustrative purposes only, to 3% and 4%, respectively. Figure 4-9 provides the comparison between the thresholds and THD with and without mitigation. It can be seen that mainly in New England zone the actual THD is higher than the thresholds. The optimization is applied to select the optimal solution in order to bring the THD below the thresholds. Both PF and harmonic reduction at the sources are provided for optimization. As a result of the optimization, twelve alternative optimal solutions are obtained as shown in Table 4-5. One of the solutions is plotted in Figure 4-9, which shows the THD...
obtained with mitigation is well below the thresholds. PF is selected as the optimal solution though both PF and harmonic reduction at the sources are considered in optimization. Just one PF is sufficient to reduce HGI to zero in this case.

Table 4-5: Alternative solutions.

<table>
<thead>
<tr>
<th>Alternative solutions: Rating and location</th>
</tr>
</thead>
<tbody>
<tr>
<td>100Mvar PF at B24</td>
</tr>
<tr>
<td>100Mvar PF at B26</td>
</tr>
<tr>
<td>100Mvar PF at B27</td>
</tr>
<tr>
<td>200Mvar PF at B30</td>
</tr>
<tr>
<td>100Mvar PF at B37</td>
</tr>
<tr>
<td>200Mvar PF at B47</td>
</tr>
</tbody>
</table>

Figure 4-9: THD performance (with mitigation by PF at B24) compared with the zonal thresholds.

4.4.6.2.2 Case 2: Zonal Mitigation (Three Zones) with Assumed 90% Penetration of RES

The system is divided into three zones, as shown in Figure 4-10. The thresholds of the three zones are set, for illustrative purposes only, to 2%, 3% and 4%, respectively. Other settings are the same as those in case 1, and both PF and harmonic reduction at the source are considered in optimization.
In this case, four alternative solutions are obtained, as given in Table 4-6. Same as in Case 1, only PF is selected as the optimal solution, and just one PF is sufficient to reduce the HGI to zero. The THD obtained from the four alternative solutions are plotted in Figure 4-11. It shows that the THDs are greatly improved and they are well below the thresholds.

Table 4-6: Alternative solutions.

<table>
<thead>
<tr>
<th>Alternative solutions: Rating and location</th>
</tr>
</thead>
<tbody>
<tr>
<td>100Mvar PF at B24</td>
</tr>
<tr>
<td>100Mvar PF at B67</td>
</tr>
<tr>
<td>100Mvar PF at B37</td>
</tr>
<tr>
<td>100Mvar PF at B68</td>
</tr>
</tbody>
</table>

Figure 4-11: THD performance of obtained solutions compared with the zonal thresholds.
4.4.6.2.3 Case 3: Global Optimization with with Assumed 90% Penetration of RES

In this case, the 3% threshold is used globally for all buses in the network. The same solutions are obtained as in the case of zonal optimization with two zones (i.e., case 1). Only PF is selected as the optimal solution though both PF and harmonic reduction at the source are made available for optimization. The THD obtained by all alternative solutions are given in Figure 4-12. It can be seen that a relatively larger variation of THD exists around buses 20-30. To trace down the performance of individual harmonic orders, the IHD of harmonic orders 2-25 is obtained after placing PF at B24. For each harmonic order, the worst IHD performance among 68 buses is provided in Figure 4-13, together with the thresholds for individual harmonic orders. It can be seen from the comparison that the individual THD performance is within the limit set by IEC standards.

To further test the robustness of the mitigation strategy obtained, harmonic performance is evaluated when the parallel power lines are disconnected from the system. Lines L41 and L42 are parallel power lines that connect the two sections of the power system, and lines L44 and L45 are another pair of parallel power lines. The THD obtained with the disconnection of one parallel power line among L41, L42, L44 and L45, is given in Figure 4-14 (a), as well as the results obtained with the disconnection of two parallel power lines at the same time. It can be seen that the THD is little affected by the disconnection of one or two parallel power lines, in comparison with the THD that is obtained without the disconnection of power lines. The results demonstrate the robustness of the mitigation strategy obtained. To further present the difference of THD when disconnecting one or two parallel lines, the THD obtained by disconnecting L41 and L44 simultaneously is compared with the THD obtained by disconnecting L41 or L44 individually, as given in Figure 4-14 (b). It can be seen that the curve obtained by the disconnection of two power lines at the same time overlaps with the THD obtained by only disconnecting L41 at buses around B45-B50, but overlaps with the THD obtained by only disconnecting L44 at buses B55-B65. The same conclusion applies to the case of disconnecting L42 and L45 as shown in Figure 4-14 (c).

Figure 4-12: THD performance (with PF at selected buses) compared with global thresholds.
To further investigate whether the individual harmonic orders are affected by the disconnection of power lines, the individual harmonic orders are obtained by disconnecting one or two parallel power lines among L41, L42, L44 and L45. IHD is not affected when disconnecting L41 or/and L42, as shown in Figure 4-15 (a-b). However for L44 and L45, two harmonic orders (14 and 24) exceed the limit, as shown in Figure 4-15 (c-d). When disconnecting two parallel lines simultaneously, three harmonic individual orders (14, 22 and 24) exceed the limits, as shown in Figure 4-15 (e-f). It can be seen that individual harmonic performance is slightly affected by disconnecting particular parallel lines, though it is not reflected by THD.
Figure 4-14: THD obtained after disconnection of parallel lines.
(a) Disconnect L41
(b) Disconnect L42
(c) Disconnect L44
(d) Disconnect L45
(e) Disconnect L41 and L44
(f) Disconnect L42 and L45

Figure 4-15: Individual harmonics obtained after disconnection of parallel lines.
4.4.6.2.4 Case 4: Global Optimization with Assumed 60% Penetration of RES

Case 4 yields almost the same solutions as in the case of 90% penetration except for the rating of PF at B53. It is reduced to 100 Mvar in this case. Only the PF is selected as the optimal solution, and one PF is sufficient to reduce HGI to zero. Compared with Figure 4-12, it can be seen that the THD are in general lower in Figure 4-16 due to the smaller penetration level in this case.

To analyze the relationship between THD and PF rating, PF rating at B24 is varied between 25 Mvar and 200 Mvar. The results are given in Figure 4-17. It can be seen that the THD decreases as the PF rating at B24 increases.

Figure 4-16: THD performance with PF at selected buses.

Figure 4-17: THD obtained by different ratings of PF at Bus 24.
4.4.6.2.5 Case 5: Global Optimization with Assumed 60% Penetration of RES - Based on Harmonic Reduction at Sources only

In this case, only the potential solutions of harmonic reduction at the sources are provided for optimization. The convergence of HGI is given in Figure 4-18. It can be seen that the HGI cannot reach zero even with the increased number of locations equipped with harmonic reduction. The HGI reaches the minimum when four locations (30% reduction at PV7, 50% reduction at PV10, 30% reduction at WF1 and 40% reduction at WF5) are implemented with harmonic reduction. The THD obtained by harmonic reduction at the four locations is given in Figure 4-19, which shows that some buses still have a THD higher than the thresholds.

![Figure 4-18: Harmonic Gap Index convergence with harmonic reduction at increased number of locations.](image)

![Figure 4-19: THD obtained by harmonic reduction at four locations.](image)
To test the performance of implementing harmonic reduction only, the THD obtained by 30% and 50% harmonic reduction at all PVs only is given in Figure 4-20. It can be seen that THD is improved when the harmonic reduction ratio is increased. The same process is applied to the case of harmonic reduction at all wind turbines only. However, in this case THD is not improved even when increasing the harmonic reduction ratio. In general, the harmonic reduction at PV plants only, performs better than the case of harmonic reduction at wind turbines only.

![Figure 4-20: Harmonic reduction (30% and 50%) at PV only and WF only.](image)

To further investigate the relationship between THD and the harmonic reduction ratio, two harmonic injection sources are chosen for the following analysis. WF5 and PV7 are selected here as the most effective in reducing THD if harmonic reduction at the source is simulated. The results are given in Figure 4-21 and Figure 4-22 respectively. It can be seen that there is no linear relationship between the scaling factors and THD improvement for both cases, and sometimes more harmonic reduction can result in increased THD.
Figure 4-21: THD obtained from different scaling factor at WF 5 connected to Bus 53.

Figure 4-22: THD obtained from different scaling factor at PV7 connected to Bus 17.

It can be seen from the study above that the main feature of the proposed mitigation is that it is able to search for the solutions which can ensure the THD within the threshold. For the case study presented here, the technical optimization can provide a number of alternative solutions which are able to bring THD below the thresholds. Seen by the optimization algorithm, these alternative solutions have the same performance as their HGIs are all zero though their mitigation capabilities are actually different. The difference in the mitigation capability among the obtained alternative solutions is not reflected/addressed by the study focusing on technical optimization only. The results will vary around the selected solution if more PF ratings (with smaller rating intervals) are adopted.
for the pool. Though it will provide more precise PF rating, it also suggested heavier computation load if the size of the pool gets larger.

4.5 Techno-Economic Optimization for Harmonic Mitigation in Transmission Networks

Harmonic phenomena cause great financial losses to both utilities and customers as a result of financial penalty, energy losses, malfunction of equipment/machines, and damage to the equipment etc. CIGRE/CIRED C4.107 identifies the critical effects of harmonic phenomena from the financial point of view, and introduces approaches that are used to evaluate the financial losses caused by harmonic distortion [141]. Specifically, the consequence of the presence of harmonic phenomena (or the resonant operating conditions) can be analyzed from the aspects, presented in the following sections.

4.5.1 Financial Consequence of Harmonic Phenomena

As discussed in Section 4.2.2, the financial consequences of harmonic distortion mainly take into account three aspects: energy/power losses, losses due to premature ageing and losses due to equipment malfunction. The financial loss calculation here adopts deterministic cost analysis in literature rather than probability analysis mentioned in Section 4.2.2. The main cost analysis equations and related information used in the examples presented in this report are given in the subsections that follow, while further details on particular PQ cost estimation can be found in Section 4.2.2.

4.5.1.1 Energy/Power Losses

The energy/power losses due to harmonic phenomena can be reflected by a number of forms, such as dielectric, copper and core losses in the connected equipment/machines. The power losses can be calculated separately for each type of machine, due to the fact that the impacts of harmonic phenomena on different types of machine vary and consequently their evaluations vary as well. For instance, the power losses for electrical motors can be evaluated by the following equation [141]:

$$ P_M = 3 \sum_{h=h_1}^{h_{\text{max}}} \left( \frac{V^h}{Z^h} \right)^2 R^h_M + P_{CO} \sum_{h=h_1}^{h_{\text{max}}} \left( \frac{V^h}{Z^h} \right)^{m_M} \frac{1}{h^{n_a}} $$ (4.25)

where $R^h$ and $Z^h$ are the equivalent resistance and impedance at harmonic order $h$ respectively; $V^h$ denotes the voltage harmonic at order $h$; and $P_{CO}$ is the core loss.

4.5.1.2 Financial Losses due to Premature Ageing

The power losses in core/copper of machines caused by harmonic phenomena usually result in increased temperature in the machines. This imposes extra thermal stresses to the insulation
materials, and potentially causes malfunction of the machines and the reduced life time of service. Furthermore, the presence of harmonics may cause the increase of peak factor in voltage, and consequently results in additional electric stress to the machines. The thermal life time can be simplified and modeled as [142], [143]:

\[ L = L_0 (K_p) -n_p e^{-\theta} \]  

(4.26)

where \( K_p \) is the peak factor of the voltage waveform, defined as the ratio between the distorted voltage and the peak value of the fundamental voltage. Coefficient \( n_p \) is related to and set based on the distorted shape of the waveforms. Further details on the calculation of losses due to premature ageing can be found in Section 4.2.2.

4.5.1.3 Financial Losses due to Equipment Malfunction

Equipment malfunctions may cause significant financial losses to the utilities and customers depending on how critical the failed equipment/machines are in the operating system or in the manufacturing process. The financial losses to the customer can be usually obtained by estimation/surveys from the customers. As for the malfunction of equipment in grids, it has wider effects and can impact all customers who are closely related to or fed by the equipment. Equipment malfunctions can also cause premature ageing issues as discussed earlier.

There are also other potential losses caused by harmonic phenomena, such as the derating of equipment. Sometimes the harmful effects of harmonic phenomena are unnoticed until the actual failure of the equipment. For instance, transformers can run for a long period under the presence of harmonic voltages and currents, but may fail quickly when there are certain triggers/changes in operating conditions. Therefore, it is very important to properly mitigate the harmonic phenomena even when there is no reported equipment failure that is obviously caused by harmonic phenomena. The utilities should properly examine the harmonic performance in the grids, and optimally mitigate the harmonic phenomena by taking into account both technical and financial aspects, in order to prevent the propagation of harmonics causing a wider effect on the grids' and customers' equipment and their operation.

4.5.2 Financial Assessment and Problem Description

When financially assessing harmonic mitigation at planning level, it is important to consider the benefits during the entire life span of the deployed solution. The upfront investment made for a mitigation solution pays back its returns only during the life span duration. This makes it important to consider the net present value of future benefits, as well as the net present value of future maintenance. This brings the investment cost and its future benefit to a common ground/level of comparison with the planning or deployment year as the reference. The net present value approach accounts for the factors like inflation (denoted as \( i \)), discount rate (denoted as \( r \)) and escalation rate...
(denoted as \(e\)) required for the assessment of time value of money. Net present value (NPV) can be calculated using the following equation:

\[
NPV = CI + \frac{\sum_{t=0}^{n}(C_{tb} + C_{tc}) \times (1 + e)^t}{(1 + r)(1 + i)^t}
\]  

(4.27)

where CI denotes the initial capital investment (usually expressed as a negative amount), \(C_{tb}\) denotes the benefit component (difference between original cost and remaining cost after the installation of the solution) occurring at the beginning of time period \(t\); and \(C_{tc}\) denotes the cost component (annual maintenance cost) occurring at the beginning of time period (usually expressed as a negative amount).

In the study, the problem is defined as an optimisation problem, which applies the mitigation solutions in the network optimally in order to minimise the overall financial cost that includes the investment cost, operation/maintenance cost and the cost caused by harmonic phenomena, and to maximise the benefits as a result of the application of mitigation solution. Simultaneously, in planning harmonic mitigation, the provision of acceptable harmonic levels should be facilitated globally. The provision of harmonic performance is considered as the technical requirement and treated as a constraint to be imposed during the optimisation process. In the study, the technical requirement is included in the objective function using Lagrangian relaxation \[144\]. The present value of annual operation/maintenance cost and cost due to harmonic phenomena during the entire lifespan of the deployed solution is calculated using NPV method. To achieve the aforementioned objectives, an objective function \((F)\) to be minimised in the optimisation problem is defined as:

\[
F = C_m - C_b + \beta \times GHGI
\]  

(4.28)

\[
C_m = C_{ICI} + \frac{\sum_{t=0}^{n}(C_{AnnOpMai}^t) \times (1 + e)^t}{(1 + r)(1 + i)^t}
\]  

(4.29)

\[
C_b = \frac{\sum_{t=0}^{n}(C_{PQ}^t - C_{PQ}^{t_m}) \times (1 + e)^t}{(1 + r)(1 + i)^t}
\]  

(4.30)

where \(C_{PQ}^t\) and \(C_{PQ}^{t_m}\) denote the costs of harmonic phenomena without and with mitigation, respectively at time period \(t\) and \(\beta\) is a Lagrange multiplier which imposes the penalty to the selected mitigation scheme if the technical constraints are violated. If GHGI is larger than zero, it means that there are technical violations of THD above the thresholds. The total period for evaluation is 40 years. To avoid confusion, all cost variables in (4.28)-(4.30) are expressed as positive values \(\$(\$\)). It can be seen that the smaller \(C_m\) (which consists of the initial capital cost \(C_{ICI}\) and annual operation/maintenance cost \(C_{AnnOpMai}^t\)) is, the less investment cost is required. The financial benefit of placing the mitigation techniques, denoted as \(C_b\), is calculated by \((C_{PQ}^t - C_{PQ}^{t_m})\), as shown in (4.30). In (4.28), negative sign is applied to \(C_b\) so that the optimisation procedure will attempt to maximise the benefit. \(\Delta C = (C_m - C_b) < 0\) suggests that the subsequent financial benefits resulting
from the application of mitigation techniques will cover the initial capital investment and maintenance cost of these mitigation techniques, and placing the selected mitigation scheme is beneficial in the long run.

4.5.3 Simulation and Results

4.5.3.1 Case 1: Global Mitigation with Assumed 90% Penetration of RES - Based on both PF and Harmonic Reduction at Sources

Both PF and harmonic reduction at sources are provided as potential solutions. The global THD thresholds are set to 3%. The ratings PFs of 30, 50, 100, 150, 200 Mvar are applied in the study. The options of harmonic reduction ratios are 50%, 60% and 70%, and their corresponding costs are set to 130%, 150% and 170% of the cost of converters respectively. The cost of converters is 0.15 euro/W \[145\]. \(\beta=1 \times 10^8\), which is chosen by ensuring that the GHGI has greater influence on the overall objective function \(F\) if the technical constraints are strictly enforced. The assumed harmonic reduction levels and associated costs to achieve them are for illustrative purposes only. Any other values could be used without any loss of generality of the approach. With different values of these parameters though, different results would be obtained and consequently different conclusions drawn.

The 200 Mvar PF placed at B37 is selected as the optimal solution. The HGI obtained with the optimal solution is zero, and the THDs at all buses are given in Figure 4-23, which shows that all THDs are well below the thresholds given.

The comparison between the harmonic performance obtained based on techno-economic analysis (200Mvar PF at B37) and technical analysis (100Mvar PF at B37) is given in Figure 4-24. It can be seen that the THD obtained based on techno-economic optimisation is lower than that on technical optimisation only.

The technical optimisation aims to make sure the obtained THDs are below the thresholds. However, the techno-economic optimisation not only aims at bringing THDs below the thresholds, but also tries to reduce the THDs as much as possible in order to reduce the overall PQ cost. In this case higher rating is adopted for PF in techno-economic analysis, as the reduction of PQ cost due to the increased PF rating is higher than the increase of mitigation cost. The PQ cost with mitigation, benefit, mitigation cost and the assessed objective functions are given in Table 4-7. It can be seen that the PQ cost is greatly reduced when the optimal mitigation is implemented. The mitigation cost is less than the benefit, which shows the feasibility of the optimal solutions.
Figure 4-23: THD obtained without and with mitigation based on techno-economic analysis.

Figure 4-24: Comparison between THDs obtained based on technical analysis and techno-economic analysis.

Table 4-7 Techno-economic analysis results of the optimal solution for case 1.

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PQ cost without mitigation ($)</td>
<td>2.165e+08</td>
</tr>
<tr>
<td>PQ cost with mitigation ($)</td>
<td>2.0512e+07</td>
</tr>
<tr>
<td>Benefit ($)</td>
<td>1.9601e+08</td>
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<tr>
<td>Mitigation cost ($)</td>
<td>1.1424e+08</td>
</tr>
<tr>
<td>HGI</td>
<td>0</td>
</tr>
<tr>
<td>$F$</td>
<td>-8.18e+07</td>
</tr>
</tbody>
</table>
4.5.3.2 Case 2: Global Optimization with Assumed 90% Penetration of RES - Based on Harmonic Reduction at Sources only

In this case, only the potential solutions of harmonic reduction at the sources are provided for optimization. HGI cannot reach zero for this case. The minimum HGI obtained is 4.815 while harmonic reduction is implemented at three locations (50% reduction at WF 10, 2 and 5 respectively), as given in Table 4-8. The best benefit is also obtained for this solution. The results of applying harmonic reduction at one (50% reduction at WF 10) and four harmonic sources (50% reduction at WF 10, 2 and 5, and 50% at PV2) are given in Table 4-9 and Table 4-10 respectively. It can be seen that $F$ increases when harmonic reduction is implemented at more locations, as the mitigation cost outweighs the benefits and HGI. As the number of converters used for harmonic reduction at the sources is increased, the mitigation cost is significantly increased, but the PQ cost varies slightly compared to the increase of mitigation cost. The THD obtained when implementing different number of harmonic reductions at sources is given in Figure 4-25, and it can be seen that the THD with mitigation is visibly decreased compared with the THD without mitigation, while some buses still have THD that are higher than thresholds.

To further investigate the effect of varying the settings of harmonic reduction cost, the solution which has the lowest HGI is selected for study. The cost of harmonic reduction is set to 120%, 150% and 200% of the original cost of converter respectively. The mitigation costs obtained are given in Table 4-11. It can be seen that the mitigation cost varies significantly when changing the cost setting.

The optimization based harmonic analysis above has demonstrated that the network based harmonic mitigation by installing passive filters results in better harmonic performance for both global and zonal optimizations in comparison with the solution of reducing harmonic injection at harmonic sources. In the case of techno-economic optimisation which considers both technical and economic aspects of the mitigation solutions, passive filter is also preferred as it not only can bring down the THD below the thresholds, but also at the same time outperforms the strategy of harmonic reduction at sources in terms of the reduction of PQ cost, mitigation cost and benefits. By comparing the results of the studies related to technical optimization only and the results related to techno-economic optimization, the former provide a number of alternative solutions which can all ensure that HGI reduces to zero irrespectively of the associated costs. The later on the other hand provide a solution which could further reduce the THD, if the minimisation of the overall PQ cost was not the objective, but they do not do that as this would result in an increased mitigation cost due to the use of higher rating of PF and such the cost of mitigation could exceed the cost of “the problem” itself, that was attempted to be solved in the first place.
Table 4-8: Best HGI obtained with harmonic reduction at three locations.

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PQ cost without mitigation ($)</td>
<td>2.1652e+08</td>
</tr>
<tr>
<td>PQ cost with mitigation ($)</td>
<td>1.5398e+08</td>
</tr>
<tr>
<td>benefit($)</td>
<td>6.2539e+07</td>
</tr>
<tr>
<td>Mitigation cost($)</td>
<td>2.7737e+09</td>
</tr>
<tr>
<td>HGI</td>
<td>4.815</td>
</tr>
<tr>
<td>$F$</td>
<td>3.19e+09</td>
</tr>
</tbody>
</table>

Table 4-9: Results obtained with harmonic reduction at one location.

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PQ cost without mitigation ($)</td>
<td>2.1652e+08</td>
</tr>
<tr>
<td>PQ cost with mitigation ($)</td>
<td>1.6386e+08</td>
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<tr>
<td>benefit($)</td>
<td>5.2658e+07</td>
</tr>
<tr>
<td>Mitigation cost($)</td>
<td>6.7679e+08</td>
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<tr>
<td>HGI</td>
<td>6.4834</td>
</tr>
<tr>
<td>$F$</td>
<td>1.35e+09</td>
</tr>
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</table>

Table 4-10: Results obtained with harmonic reduction at four locations.

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PQ cost without mitigation ($)</td>
<td>2.1652e+08</td>
</tr>
<tr>
<td>PQ cost with mitigation ($)</td>
<td>1.6701e+08</td>
</tr>
<tr>
<td>benefit($)</td>
<td>4.9510e+07</td>
</tr>
<tr>
<td>Mitigation cost($)</td>
<td>4.1939e+09</td>
</tr>
<tr>
<td>HGI</td>
<td>7.2934</td>
</tr>
<tr>
<td>$F$</td>
<td>4.87e+09</td>
</tr>
</tbody>
</table>

Figure 4-25: THD obtained when harmonic reduction is implemented at different numbers of locations.
Table 4-11: Mitigation cost for the solutions of implementing harmonic reduction at three locations.

<table>
<thead>
<tr>
<th>Mitigation cost (%) in $</th>
<th>Mitigation cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>120%</td>
<td>2.5604e+09</td>
</tr>
<tr>
<td>150%</td>
<td>3.2004e+09</td>
</tr>
<tr>
<td>200%</td>
<td>4.2673e+09</td>
</tr>
</tbody>
</table>

4.6 Probabilistic Sequential Based Harmonic Mitigation

From a different perspective, in this section a probabilistic sequential methodology is applied to control the harmonic propagation in transmission networks. One of the prerequisites of the method is the identification of the most effective point to mitigate harmonics in real and bulk transmission networks. In this methodology the major factors influential in the harmonic performance of a transmission network are assumed to be variable. Variables and their effects on the harmonic performance of the network are comprehensively analyzed in a probabilistic framework. The method is applicable to any topology of power system at network stage or in existing power network. It also provides valuable recommendations for developing networks focusing on the high penetration of PE devices in the future.

Harmonic flow through the network is dependent on the amplitude of the equivalent harmonic impedance of a typical harmonic order at a certain point of the network. Harmonic flows are complex and associated with many unpredictable issues since the harmonic impedance consistently varies. This is due to the several reasons, mentioned below:

- **Stochastic harmonic sources**: there are numerous harmonic sources generating or causing harmonics stochastically. For example, nonlinear loads individually cause harmonic distortion with different and variable nonlinear behaviour. Furthermore, PE based RES unpredictably generate harmonics due to their stochastic and intermittent generation.

- **Uncertainty in harmonic sources’ location**: harmonic sources erratically connect and disconnect to the network. For instance, the grid-connectivity status of nonlinear loads and RES cannot be determined with absolute certainty. Accordingly, equivalent harmonic impedance of the network continuously changes that results in continuous modification in the harmonic propagation map (HPM) of the network.

- **Harmonic cancellation phenomenon**: in a power network with massive integration of PE devices or harmonic sources in general, harmonic emissions might cancel each other. The probability of harmonic cancellation phenomenon increases by increasing the number of PE devices but it is fairly difficult to calculate the cancellation rate at a typical point in a real network.

Regarding the above mentioned features of harmonics in power networks, a probabilistic methodology is described for transmission networks. As it is shown in Figure 4-26, several influential factors in harmonic propagation are addressed in the methodology. These factors are the variables of the method. After each gradual and stochastic modification of the variables, harmonic performance
of the network is analyzed. After adequate modifications and analysis, the following questions can be answered:

1) How different variables affect the HPM of the network individually?
2) Which variable has the most influence on the present harmonic status of the network?
3) Where is the most vulnerable point of the network in terms of harmonics?
4) Where is the most effective point for curtailing the harmonic propagation?
5) Which is the most effective PE device to limit harmonic propagation?

In addition to understanding the harmonic propagation phenomenon, the answers to the above questions facilitate identification of the best techno-economic mitigation solution. For example, by answering the first two questions, the contribution of each harmonic source in the existing network to harmonic pollution can be roughly determined. Accordingly, in terms of harmonic pollution, the responsibility of utility and customers (including private DGs) can be identified with good accuracy. Regarding the last two questions, the most effective point or the location of the most effective PE device in the harmonic performance of the network can be the best point for harmonic mitigation since a larger area would be compensated. It is noteworthy that both THD and individual harmonic distortion (IHD) of the network are traced in the method so the aforementioned questions need to be answered with respect to THD and IHD.

The mutual effect of the variables needs to be paid attention to as well. For example, by a simultaneous modification of two or more variables, harmonic performance of the network might unexpectedly change due to the harmonic cancellation phenomenon. With high probability, the HPM might significantly change as well. As a result, many scenarios should be defined to comprehensively analyze the harmonic performance of the network when the effect of each variable is investigated with/without consideration of the mutual effects. However, one or more of the variables might be ignored depending on the amount of available information about the network. For instance, in cases of no plan for the extension of RESs in the future, “var1” can be ignored and the methodology assumes the RESs’ location as a constant (see Figure 4-26). In this case, the number of scenarios reduces as well. Note that each scenario contains many sub-scenarios.
4.6.1 Harmonic Analysis

Harmonic analysis of real networks is investigated when trying not to over simplify the network, as far as possible. In this regard, load profile, synchronous generators and PE based RESs, system parameters corresponding to transformers and transmission lines (with consideration of skin effects) are modeled in detail based on actual data. It is noteworthy that uncertainty in the loading condition and the available RES is considered as well. A one-week analysis is carried out in the research. As a result, considering a 10-min interval for harmonic assessment of the network, 1008 operating points are acquired for each sub-scenario during the week. For each operating point, after the execution of optimal power flow, relevant data feeds to the harmonic load flow section to scan THD and IHD (up to 25th harmonic order) of the network. Then, the week’s THD and IHD assessment of the network is calculated by using 95 percentile value. Analyzing the IHD values, harmonic propagation points (HPPs) of the network can be recognized. Simply, HPP is a point whose harmonic voltage at a given order is higher than those of other points connected to the HPP. Therefore, harmonic current at the respective order merely propagates from the HPP to the neighbouring points so no harmonic current flows across the HPPs. The HPP is of great importance because HPM of the network can be produced by tracing the harmonic current flow at each harmonic order. As a result, 25 HPMs can be obtained for each sub-scenario during a week. Comparing the HPMs of a scenario, the most repeated HPM(s) properly represents the behaviour of the scenario. The influence of each variable on the harmonic performance of the network can be estimated by analyzing the representative HPMs corresponding to all scenarios. This estimation facilitates identification of the predominant variable responsible for the harmonic pollution of the network and provides valuable supplementary information for future network development plans.

4.6.2 Harmonic Mitigation

Another benefit of HPP is the utilization of this point in harmonic mitigation studies. The best point for harmonic mitigation is that which has the highest propagation rate at a harmonic order but not a point with the highest vulnerability (so the one with the highest THD or IHD). Among all HPPs gathered from all scenarios, the most frequent HPP(s) can be the best candidate to be considered for harmonic mitigation. In cases of multiple points being recognized as very frequent HPPs, that one with the highest IHD should be chosen for harmonic mitigation. This point influences the most strongly the harmonic performance of the network as it facilitates the propagation of harmonics to other parts of the network. By the suppression of harmonics at this point a propagation to other parts of the network can be limited. Thereafter, this HPP is labeled as “the most influential HPP” (MIHPP).

In this report two harmonic mitigation approaches are considered: centralized approach and device based approach. In the centralized approach, power quality conditioners (especially passive filters) are placed at MIHPP. It is recommended that different passive filters are installed at MIHPP. One might use multiple-tuned PFs to mitigate harmonics at multiple frequencies in case the MIHPPs are at similar locations at those frequencies.
In the device based approach, the harmonic emission from PE device with the highest negative effect on MIHPP is reduced, such that IHD of MIHPP is also decreased. Note that the device might be at MIHPP, therefore, improvement of the device directly affects the propagation rate of MIHPP resulting in efficient mitigation. Based on the effectiveness of the two mitigation approaches in IHD reduction of MIHPP, the cheapest approach is considered for harmonic mitigation of the network. The process of identification of and reduction of harmonic emission by the most influential PE device continues until there is no violation of harmonic thresholds in the network. Figure 4-27 shows the flowchart of the developed methodology.
Figure 4-27: Proposed probabilistic sequential harmonic mitigation methodology.
4.7 Harmonic Mitigation in Large Realistic Transmission Network

4.7.1 Introduction

In D5.4 [9] several study-cases were defined to assess the harmonic propagation in the large realistic test network broadly based on the Irish transmission network. The cases are defined in terms of the rate of harmonic pollution of the network considering different influential parameters. These parameters are the percentage of nonlinear loads, the droop characteristic of synchronous generators and the percentage of SNSP. The droop characteristic and the percentage of SNSP and how these parameters can be calculated are comprehensively explained in D5.4. In this regard, Table 4-12 shows the cases and the characteristics of each case corresponding to the parameters. In this table, the reference case comprises an SNSP level of 60 % and corresponds to a present-day scenario in Ireland, where 65 % SNSP is the maximum limit. This case is used to compare the other cases to the initial condition and together then access the harmonic performance of the network. Therefore, the blank boxes in Table 4-12 show that there is no change with respect to the reference case.

Table 4-12: The reference and study-cases of Irish network.

<table>
<thead>
<tr>
<th>Cases</th>
<th>Loading condition</th>
<th>SNSP (%)</th>
<th>$1/R_{eq}$ [MW/Hz]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference case</td>
<td>-</td>
<td>60</td>
<td>1685</td>
</tr>
<tr>
<td>Case 1</td>
<td>80% linear, 20% nonlinear</td>
<td>70</td>
<td>1366</td>
</tr>
<tr>
<td>Case 1.1</td>
<td>50% linear, 50% nonlinear</td>
<td>70</td>
<td>1366</td>
</tr>
<tr>
<td>Case 1.2</td>
<td>80% linear, 20% nonlinear</td>
<td>70</td>
<td>1366</td>
</tr>
<tr>
<td>Case 1.3</td>
<td>50% linear, 50% nonlinear</td>
<td>70</td>
<td>1366</td>
</tr>
<tr>
<td>Case 2</td>
<td>-</td>
<td>80</td>
<td>890</td>
</tr>
<tr>
<td>Case 3</td>
<td>-</td>
<td>90</td>
<td>677</td>
</tr>
<tr>
<td>Case 3.1</td>
<td>-</td>
<td>90</td>
<td>906</td>
</tr>
<tr>
<td>Case 3.2</td>
<td>-</td>
<td>90</td>
<td>1685</td>
</tr>
</tbody>
</table>

The harmonic distortion corresponding to the cases is represented in Table 4-13 as it was obtained and shown in D5.4. In this table, only the buses with the highest THD are listed. It should be noted that uncertainty in harmonic injection by loads is considered in this study. In this regard, 500
stochastic harmonic emission spectra are generated for each harmonic source. Then, the 95th percentile value of THD is calculated for each bus to properly assess the harmonic performance of the network. The results regarding individual harmonic distortions are available in D5.4.

Table 4-13: THD of buses in different cases (Irish network).

<table>
<thead>
<tr>
<th>Cases</th>
<th>110 KV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Bus Number</td>
</tr>
<tr>
<td>Reference case</td>
<td>110_199</td>
</tr>
<tr>
<td>Case 1</td>
<td>110_177</td>
</tr>
<tr>
<td>Case 1.1</td>
<td>110_108</td>
</tr>
<tr>
<td>Case 1.2</td>
<td>110_177</td>
</tr>
<tr>
<td>Case 1.3</td>
<td>110_108</td>
</tr>
<tr>
<td>Case 2</td>
<td>110_177</td>
</tr>
<tr>
<td>Case 3</td>
<td>110_177</td>
</tr>
</tbody>
</table>

Based on the results shown in Table 4-13, the harmonic mitigation of the Case 1.1 and Case 3 are considered in this report for illustrative purposes. The reason for selecting these two cases is that the effect of nonlinear loads on the harmonic performance of the network is predominant in Case 1.1 and the effect of SNSP is predominant in Case 3. As it is shown in Table 4-13, THD in Case 1 (the case which considers the emissions of nonlinear loads) is higher than that of the reference case. Furthermore, Case 1.1 (50% of loads in the network are nonlinear loads) has the highest THD among the sub-cases of Case 1. Considering the penetration level of SNSPs, and based on Table 4-13, it can be seen that in Case 3 the highest THD is obtained when the penetration level of SNSP was 90%.

4.7.2 Harmonic Mitigation

Due to the large size of the test network, a simple harmonic mitigation strategy is used. This strategy is based on the highest THD. The bus with the highest THD is considered for harmonic mitigation. Selective-harmonic passive filters are used to mitigate harmonics at the detected bus with the highest THD. After analysing harmonic spectrum of the detected bus the predominant harmonic order is extracted. Then a passive filter tuned at the predominant frequency is placed at the bus. In case there are two or more harmonics with a distortion rate close to each other (less than 0.5%) there would be multiple predominant frequencies that result in multiple-tuned selective passive filter. After placement of the filter, the THD of the network is assessed again. In the case of any violation of the thresholds, the aforementioned process is repeated until all the violations are removed. Note that violation of both THD and IHD related thresholds are checked during the mitigation process.
Thereafter, this harmonic mitigation strategy is called “highest-THD based harmonic mitigation” (HTHD). Figure 4-28 shows a flowchart of the mitigation strategy.

4.7.3 Simulation Results

As mentioned before Case 1.1 and Case 3 are considered for harmonic mitigation and they are separately investigated in the following subsections.

4.7.3.1 Case 1.1

Regarding the HTHD mitigation strategy and based on Table 4-13, the first candidate to place the filter is Bus 110-108 as its THD is the highest (4.85%). It was shown in D5.4 that the predominant harmonic order is 7th harmonic (HD7=4.78%). Therefore, a single-tuned passive filter (tuned at 7th harmonic order) needs to be placed at Bus 110-108. Figure 4-29 shows how the placement of this filter affects the harmonic performance of the network. This figure represents cumulative plot of number of THD violating buses with the magnitude of violations. The highest THD in the network is reduced from 4.85% (bus 110-108) to less than 4.4% (bus 110-1355), however, the number of violations of the THD threshold is increased from 104 buses to 121 buses. Note that HD7 of Bus 110-108 is reduced from 4.78% to close to 0.5%. Due to the remaining threshold violations, the mitigation process goes through the next round.

The next bus detected as the most distorted bus is Bus 110-1355 (THD=4.35%). The predominant harmonic order is detected as the 13th order with HD13=4%. As shown in Figure 4-29, after placing a selective filter (the second filter) tuned at Bus 110-1355, the number of threshold violations has significantly reduced (from 121 to 60). However, the highest THD is only slightly decreased. In fact, the highest THD in the network decreased from THD=4.35% at Bus 110-1355 to THD=4.3% at Bus 110-675. Note that HD13 is decreased from 4% to 0.6% at Bus 110-1355. Figure 4-29 represents the effect of the third filter in the network as well.
Figure 4-28: Flowchart of the harmonic mitigation strategy of large networks.

Figure 4-29: THD of test network during harmonic mitigation (Case 1.1).
Figure 4-30: IHD of test network during harmonic mitigation (Case 1.1). A) 5th harmonic, B) 7th harmonic, c) 11th harmonic, d) 13th harmonic.

In terms of IHD, Figure 4-30 shows the procedure of harmonic mitigation of the 5th, 7th, 11th and 13th harmonic after installation of the first three filters. It can be seen that each filter tuned at a specific frequency noticeably reduces harmonics at the tuned frequency.

It can be seen in Figure 4-30 that, as soon as the first filter (7th order) is installed, a significant reduction in the highest HD7 and a noticeable decrease in the number of violations (from the permissible value of HD7) at other buses have happened. Comparing the red-line to the blue-line in Figure 4-30 (b), it can be seen that the highest HD7 is reduced from 4.75% to 2.5% and the number of violations is decreased from 43 to 25. Likewise, after placing the second filter that is tuned at the 13th harmonic, the number of violations (from the permissible value of HD13) is decreased from 191 to 110. Finally, placing the third filter (tuned at the 5th harmonic), the highest HD5 is reduced from 4.1% to 2.2% and the number of violations is reduced from 13 to 1.
Table 4-14: Process of harmonic mitigation of test network Irish network (Case 1.1)

<table>
<thead>
<tr>
<th>Status</th>
<th>Most distorted bus (THD)</th>
<th>THD&lt;sub&gt;max&lt;/sub&gt;</th>
<th>Predominant order</th>
<th>Number of violated buses</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No filter</td>
<td>110-108</td>
<td>4.85</td>
<td>HD7 (4.72)</td>
<td>104  5  43  51  178</td>
</tr>
<tr>
<td>7th-order harmonic filter at 110-108 (HD7 from 4.72% to 0.5%)</td>
<td>110-1355</td>
<td>4.35</td>
<td>HD13 (4.00)</td>
<td>121 13 25 57 191</td>
</tr>
<tr>
<td>13th-order harmonic filter at 110-1355 (HD13 from 4.00% to 0.6%)</td>
<td>110-765</td>
<td>4.3</td>
<td>HD5 (4.1)</td>
<td>60  13 26 63 107</td>
</tr>
<tr>
<td>5th-order harmonic filter at 110-765 (HD5 from 4.10% to 0.8%)</td>
<td>110-116</td>
<td>4.1</td>
<td>HD13 (3.78)</td>
<td>62  1 24 63 110</td>
</tr>
<tr>
<td>13th-order harmonic filter at 110-116 (HD13 from 3.78% to 0.6%)</td>
<td>110-917</td>
<td>3.64</td>
<td>HD13 (3.42)</td>
<td>8   1 32 47 109</td>
</tr>
<tr>
<td>13th-order harmonic filter at 110-917 (HD13 from 3.42% to 1.4%)</td>
<td>110-958</td>
<td>3.27</td>
<td>HD13 (2.96)</td>
<td>4   1 28 46 18</td>
</tr>
<tr>
<td>13th-order harmonic filter at 110-958 (HD13 from 2.96% to 1.6%)</td>
<td>110-694</td>
<td>3.26</td>
<td>5&lt;sup&gt;th&lt;/sup&gt;, 7&lt;sup&gt;th&lt;/sup&gt;, 11&lt;sup&gt;th&lt;/sup&gt;, 13&lt;sup&gt;th&lt;/sup&gt;</td>
<td>1   1 25 47 10</td>
</tr>
</tbody>
</table>

On the other hand, it is proven in Figure 4-30 that harmonic reduction at a specific order has a negative effect on the harmonic distortion of other orders. For example, by using a 7<sup>th</sup> harmonic passive filter (the first filter), although there is significant reduction in HD7, there is an increase in HD5, HD11 and HD13 and the respective violations (compare the red and the blue lines in sub-
figures of Figure 4-30). Similar phenomenon can be observed for the second and the third filters as clearly represented in Figure 4-30.

The process of placing filters is continued for Case 1.1. Further to the previous three-filters, three other filters were placed in the network based on the HTHD mitigation strategy explained in Section 4.6.2. Table 4-14 shows the values corresponding to THD and IHD of the main orders after and before placing each filter. As shown, before mitigation the highest THD in the network was 4.85% and there were 104 violations from a permissible THD value. After mitigation, THD$_{\text{max}}$ is reduced to 3.26% and there is only one violation of the THD threshold. The reduction in the number of violations from IHD is shown in Table 4-14 as well.

Figure 4-31 shows how adding filters affects the harmonic performance of the network. As mentioned before, placing a filter at a bus does not guarantee that other buses except for the bus where the filter is installed will have reduced harmonic levels although there is noticeable reduction at the bus where the filter is installed. As clearly shown in Figure 4-31, harmonics are not consistently mitigated by the number of filters. It is because of “whack a mole” phenomenon [146]. This phenomenon says that “Installation of an active or passive filter on the feeder makes voltage harmonics increase on some buses, whereas it makes voltage harmonics decrease on other buses, especially at the point of installation”. It should be mentioned that as the seventh filter was added in the network, based on the HTHD mitigation strategy, harmonic distortion rate of the network was increased. In this regard, optimization based mitigation methods are recommended to be implemented for such a large network.
Figure 4-31: Harmonic mitigation in test network during placing six filters (Case 1.1). a) THD values, b) THD violations, c) HD5 violations, d) HD7 violations, e) HD11 violations, f) HD13 violations.
4.7.3.2 Case 3

Table 4-15 presents the harmonic mitigation procedure in the test network for Case 3. Before the mitigation, the THD in the network is relatively very high (THD=9.85%). There are 78 violations of THD threshold and 150 violations of HD5 threshold. The most distorted bus was detected as Bus 110-176. After derivation of the harmonic spectrum of Bus 110-176, it was clear that the fifth harmonic is predominant among other main harmonics with HD5=9.8%. As shown in Table 4-15, after placing a selective-frequency passive filter tuned at 5th harmonic at Bus 110-176, the harmonic distortion of the network is decreased significantly including the decrease in the highest THD from 9.85% to 3.1% and the decrease in the number of threshold violations from 78 buses to 2 buses. Furthermore, HD5 of Bus 110-176 is decreased from 9.8% to 0.5% and the number of violations of HD5 is reduced from 150 buses to 2 buses. Therefore, it seems that bus 110-176 was a strong 5th harmonic propagation point before placing the filter as it was identified the neighbor connected buses had lesser HD5 in comparison with bus 110-176: bus 220-754 with HD5=2.53% and bus 220-683 with HD5=2.94%.

Table 4-15: the process of harmonic mitigation in test network (Case 3).

<table>
<thead>
<tr>
<th>Status</th>
<th>Most distorted bus (THD)</th>
<th>THD$_{max}$</th>
<th>Predominant order</th>
<th>Number of violated buses</th>
</tr>
</thead>
<tbody>
<tr>
<td>No filter</td>
<td>110-176</td>
<td>9.85</td>
<td>HD5 (9.8)</td>
<td>THD 78</td>
</tr>
<tr>
<td>5th-order harmonic filter at 110-176 (HD5 from 9.8 to 0.5)</td>
<td>110-116</td>
<td>3.1</td>
<td>HD13 (2.86)</td>
<td>THD 2</td>
</tr>
<tr>
<td>13th-order harmonic filter at 110-116 (HD13 from 2.86 to 0.6)</td>
<td>260-1103</td>
<td>2.8</td>
<td>HD5 (2.6)</td>
<td>THD 0</td>
</tr>
<tr>
<td>5th-order harmonic filter at 260-1103 (HD13 from 2.6 to 0.5)</td>
<td>110-638</td>
<td>2.9</td>
<td>HD13 (2.78)</td>
<td>THD 0</td>
</tr>
<tr>
<td>13th-order harmonic filter at 260-638 (HD13 from 2.78 to 0.6)</td>
<td>38-598</td>
<td>2.1</td>
<td>HD13 (2.02)</td>
<td>THD 0</td>
</tr>
</tbody>
</table>
As shown in Table 4-15, there are still violations even after installing the first filter. By using a filter tuned at 13th harmonic at Bus 110-116 there is no violation in THD. However, there is still violation in HD5 and HD13. The third filter is a passive filter tuned at 5th harmonic placed at Bus 260-1103. Then there is no violation in HD5. However, violations in HD13 are increased from 20 buses to 78 buses because of the “whack a mole” phenomenon. Therefore, based on the HTHD mitigation method, the fourth filter tuned at the 13th harmonic is placed at Bus 110-638. Following the installation of the fourth filter, there are no violations of any thresholds, as represented in Table 4-15. The harmonic performance of the test network after harmonic mitigation is shown in Table 4-16.

Table 4-16: Test network harmonic performance after harmonic mitigation (Case3).

<table>
<thead>
<tr>
<th>Most distorted buses</th>
<th>THD</th>
<th>HD5</th>
<th>HD7</th>
<th>HD11</th>
<th>HD13</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bus number</td>
<td>Value</td>
<td>Bus number</td>
<td>Value</td>
<td>Bus number</td>
<td>Value</td>
</tr>
<tr>
<td>38-958</td>
<td>2.17</td>
<td>110-417</td>
<td>2.00</td>
<td>110-1229</td>
<td>1.34</td>
</tr>
</tbody>
</table>

Comparing the results of Case 1.1 to Case 3, it is evident that the harmonic strategy HTHD was not able to reduce harmonic levels below the thresholds in Case 1.1. On the other hand, by following the same strategy, it was possible to reduce harmonics below the thresholds in Case 3, even though the harmonic distortion (before mitigation) in Case 3 was higher than that in Case 1.1. The reason is that the harmonic mitigation points (the busses where filters were installed) identified in Case 1.1 have not been as effective as those of Case 3 in harmonic reduction.

4.8 Conclusions

The Section 4 presents comprehensive study on developing an efficient strategy for harmonics mitigation in power networks and discusses techno economic merits of different approaches to harmonic mitigation. A variety of harmonic mitigation strategies including PE device-based/harmonic source based harmonic mitigation, i.e., the reduction of harmonic emission by harmonic sources, and network based harmonic mitigation, i.e., placement of harmonic filters in the network, are provided and discussed.

An optimization framework is proposed to search for the optimal mitigation solution zonally and globally. Both harmonic source and network based harmonic mitigation strategies are realized through optimization. The variability of the operating conditions during a year is addressed by selecting a set of representative operating points based on clustering of similar operating conditions occurring during the year. The penetration level of renewable energy sources was varied both as a level of installed capacity and throughout the year (in case of a fixed level of installed capacity) to account for the variability of their power generation and the influence of different penetration levels on overall harmonic performance of the network. It was found, based on assumed parameters and
constraints, that network based harmonic mitigation by installing passive filters in the network, results in better harmonic performance for both global and zonal optimization. Following a technical optimisation based mitigation a techno-economic optimisation was performed considering both, technical and economic aspects of the mitigation problem over a number of years, i.e., considering the life-span of the mitigation solution. The results show the advantage of the network based mitigation, which is able to bring harmonic performance well under the specified thresholds and greatly reduce the potential economic losses resulting from the presence of the high level of harmonics. It should be noted though that the parameters used in optimisation could greatly affect the final results and a special attention should be given to selecting appropriate technical and economic parameters used in the optimisation.

In addition to the optimization based harmonic mitigation method, the application of which can be constrained to an extent by the size of the network, a probabilistic, sequential harmonic mitigation methodology is presented to investigate harmonic propagation and mitigate harmonics in the large, realistic size transmission networks. The proposed probabilistic method can be used to identify the most effective locations for installing passive filters to solve harmonic problems in the network and to identify the most influential sources of harmonics. Finally, as a follow up from deliverable D5.4, the application and effectiveness of probabilistic, sequential harmonic mitigation is illustrated in large realistic size transmission network on a two characteristic case studies previously used in Deliverable 5.4.
5 European Practice on Power Quality Management

5.1 Motivation and Background

In modern power systems, the level of producers and consumers who are connected to the network through power electronic interface is increasing. Consequently, the network operators are seeing an increasing need to comprehensively understand the power quality related aspects and define respective limits to their systems and connections. Currently in transmission networks the knowledge in this field has been limited and therefore this topic was included into the scope of MIGRATE project.

Among the first task undertaken in MIGRATE project was to understand the current state of the art in this field and as a therefore different questionnaires were composed and sent to MIGRATE partners and other transmission system operators around Europe. Results of these questionnaires have been presented in previous deliverables. For example, general overview of range of power quality issues in current transmission networks is presented in deliverable D5.1 [30] and items related to power quality legislation in deliverable D5.4 [9]. It has been shown that the main power quality issues in Europe are mostly high and low voltages and harmonics, and the issues are mainly caused by the customers (industry more than distribution network). Regarding legislation, it was shown that in Europe, the general grid connection and system operation requirements are being harmonized by European Commission regulations. However, the legislation aspects of power quality have not reached this level of harmonization and are being dealt with in specific country and system operator level. This means that there are significant differences between the countries and further work with respect to harmonization is needed. In deliverable D5.4, it is shown that the requirements for power quality in national grid codes and in other regulation are quite limited on the one hand, but on the other hand there are some TSOs in Europe that have developed quite detailed guidelines and methodologies for allocating power quality limits for their customers. In addition, the feedback to the questionnaire indicated that majority of European TSOs support to unify the power quality legislation which should be made through national Grid Codes that are official government legislative acts.

The results from previous questionnaires provided significant amount of information considering current practice on power quality in general and its legislation among European TSOs. However, there were some items, e.g. background for system planning and customer compatibility levels, that required further clarifications and therefore additional questions were asked from the TSOs who were dealing with power quality in their network and agreed previously to provide further input if required. Results of this third questionnaire are presented in the following section.
5.2 Questionnaire

5.2.1 Introduction

In order to give recommendations for future power quality management in transmission networks additional questionnaire was composed and distributed to MIGRATE partners and to other European TSOs who had previously indicated that they are dealing with power quality and have some sort of power quality management approaches composed and available for public discussion. For this questionnaire nine responses were received. The questions asked in the questionnaire were composed following the principle to understand what kind of procedures TSOs in Europe are using for defining/setting the limits for customers with respect to power quality indices and how have they defined their planning and compatibility levels for the whole system.

The following questions were included to the questionnaire:
Q1: Do you use procedures for defining/setting the limits for customers with respect to PQ indices? If yes, then please describe your procedure for defining/setting the limits for customers with respect to PQ indices;
Q2: Do you use PQ planning levels in your system?
Q3: Do you use compatibility levels for PQ in PCC?

The respective power quality indices in question were:
- voltage and/or current harmonics;
- voltage unbalance;
- voltage flicker and fluctuation;
- voltage dips and swells.

The results of the questionnaire are presented below and in order to provide more comprehensive comparison also results from the previous questionnaire presented in MIGRATE Deliverable D5.4 on existing grid codes and national standards are included. In the following analysis question Q1 includes also information from previous questionnaire, but questions Q2 and Q3 represent only responses from TSOs that indicated that they have procedures for defining/setting the limits for new customers. Figures 5-1 to 5-3 summarize the results of the questionnaire. Blue column in the figures shows the percentage of respondents who answered yes to the question. Green columns show the percentage of responders from blue column who are using the procedures or levels for specific power quality phenomena.

5.2.2 Results of the Questionnaire

**Q1: Do you use procedures for defining/setting the limits for customers with respect to PQ indices?**

The responses to this question are combined with the results from previous questionnaire presented in deliverable D5.4. Here a total of 14 responses were obtained and analyzed. From the received feedback it is possible to conclude that 64% of the TSOs use procedures for defining/setting the power quality limits for connecting customers. When looking these results based on separate power
quality characteristics then all the TSOs who have these procedures in place have them implemented for harmonics. For other power quality characteristics, the implementation rate is lower, e.g. for voltage unbalance and voltage flicker and fluctuations it is 56% and 78%, respectively. Based on the feedback given to this question it can be concluded that none of the TSOs do not have procedures for voltage dips and swells. Considering also the answers to other questions it can be concluded that in general the levels for voltage dips and swells are available in the system but these are not directly implemented into customer specific limit allocation. The results for question Q1 are summarized in Figure 5-1.

In addition, this question had also a second part, which served the purpose of gathering information about procedures and methodologies that are used by the TSOs for defining/setting the limits for customers with respect to different PQ indices. The results indicate that there are somewhat significant differences between the European TSOs with respect to procedures for defining/setting the limits for customers considering the above-mentioned PQ indices. Some of the countries, e.g. United Kingdom, Denmark and Ireland (the procedure for allocating harmonic distortion limits for customers was described in previous MIGRATE deliverable D5.4), have very well-defined assessment procedures for grid connection of customer’s equipment. On the other hand, there are also countries that do not have any specific assessment procedures in place and instead applicable IEC standards as guides for planning levels are used. Overview of implemented approaches is given in section 5.2.3.

Q2: Do you use PQ planning levels in your system?
Based on the answers it can be stated that 89% of the TSOs who provided their feedback use planning levels in their systems. Out of these TSOs all have planning levels set for voltage harmonics. For other power quality characteristics, e.g., voltage unbalance and voltage flicker, and voltage dips
and swell respectively 63% and 50% of the respondents have implemented respective planning levels in their system. The results are summarized in Figure 5-2.

**Figure 5-2: Responses to Q2 – Do you use PQ planning levels in your system?** Blue column shows the percentage of respondents who answered yes to the question. Green columns show the percentage of responders from blue column who are using planning levels for specific power quality phenomena.

**Q3: Do you use compatibility levels for PQ in PCC?**
The answers to this question show that 56% of the TSOs use specific compatibility levels in their systems. This is significantly less than in case of general planning levels in the system. When considering different power quality characteristics then compatibility levels for harmonics, voltage unbalance, voltage flicker and fluctuations are set in each of those cases. Compatibility levels for voltage dips and swells have lower rate as 60% of TSOs who answered that they have implemented compatibility levels have implemented them for this characteristic. The results for this question are summarized on Figure 5-3.
5.2.3 Summary of Methodologies for Customer Power Quality Limit Allocation

This section summarizes the answers to the second part of question Q1, i.e. which procedures are used by the TSOs in different European countries for determining power quality related compatibility levels. The purpose of this section was to provide a generalized overview of the differences and similarities between the procedures used by different European TSOs. In general, there are four type of approaches implemented:

i) Detailed procedures for defining/setting the limits for new customers are described in grid codes and/or relevant TSO documents/national standards;

ii) Grid codes and/or relevant TSO documents contain references to procedures in applicable IEC standards;

iii) Grid codes and/or relevant TSO documents contain only planning levels but no specific procedures;

iv) PQ is unregulated by the grid code.

Generalized overview of the implemented procedures for defining/setting the limits for new customers with respect to PQ indices are given below.

**Harmonic distortion**

One of the methods for the assessment of harmonic distortion is based on knowing the levels of harmonic background distortion in the PCC for all relevant harmonic voltage components. The available harmonic distortion headroom of the planning level is calculated and shared between the planned facilities (generation or demand) connected at or near the POC of the electricity generation facility. Part of the available harmonic distortion headroom is reserved for future facilities while also functioning as a safety buffer in the event of deviations.
Another assessment procedure is based on the concept of coordination of EMC, which ensures that the compatibility levels in LV networks comply with IEC 61000-2-2. For this purpose, the compatibility level is divided between the network levels, so that proportional contribution per network level results in the compatibility level at LV. At each of the network level, the available harmonic distortion headroom is divided proportionally between customer facilities within the same network level. Future planned facilities should be also considered.

**Voltage unbalance**
The methodology implemented is based on defining voltage unbalance contribution vector, which means voltage unbalance contribution resulting from the connection of the electricity generation facility to the transmission grid. This vector is the difference between the voltage unbalance vectors, determined in the electricity generation facility’s PCC after and before the electricity generation facility is connected.

**Voltage flicker and fluctuation**
Assessment of step voltage change, flicker and rapid voltage change (RVC) are combined into one methodology with multiple stages. Firstly, step voltage change is assessed. This is followed by either flicker or RVC depending on whether voltage change profile is within the regulation or not. Assessment of flicker is divided into three stages, where Stage 2 and 3 are used for HV. Stage 2 is an assessment of flicker levels against a specified planning level. The assessment does not require the existing flicker background level to be considered. Where expected flicker severity exceeds the limit in Stage 2, the disturbing equipment may be eligible for Stage 3 assessment. Stage 3 assessment takes into account existing flicker background level and emission levels from the disturbing equipment at the PCC.

### 5.2.4 Conclusions

Based on the feedback from European TSOs, it can be stated that with respect to power quality legislation significant differences between different European TSOs exist. There seems to be limited coordination between utilities with respect to power quality coordination and assessment in transmission level. In general, some of the TSOs have quite detailed assessment procedures, some even with multiple stages, and other have quite limited approaches. Based on the questionnaire 89% of answered TSOs have system planning level procedures implemented while 56% have also implemented compatibility procedures. The most widely considered power quality phenomenon is harmonics followed by voltage flicker and unbalance.
5.3 Conclusions and Recommendations

Based on the analysis with respect to power quality management the following can be concluded and

Main conclusions:
- Importance of power quality among European TSOs is increasing and more resources are allocated to its management;
- The most relevant power quality characteristic considered in Europe is harmonics followed by voltage flicker and unbalance;
- Most of the TSOs who deal with power quality have respective procedures available for defining/setting limits for new customers connections and for compliance verification;
- In majority of cases respective CENELEC and IEC documents are used for determining power quality limits;
- Most TSOs have system planning levels for power quality characteristics and less TSOs have determined compatibility levels;
- Different methodologies are implemented by European TSOs in order to determine respective planning and compatibility levels in the system and for customers.

Recommendations:
- Formation of either ENTSO-E or CIGRE working group to harmonize power quality management in transmission networks;
- Agreement of unified approaches for determining system planning and customer compliance levels;
- Main power quality related legislative aspects should be covered in respective Grid Codes;
- Legislative documents should include procedure for defining/setting limits for different PQ phenomena, procedure for monitoring, and procedure for compliance verification.
6 Conclusions

Power electronic devices are elementary components of many renewable-energy power plants as well as of different types of flexible ac transmission system (FACTS) devices. This document focuses on mitigating the power quality (PQ) disturbances arising from the high share of power electronic (PE) devices in present and future transmissions grids. For this purpose, a set of comprehensive methods to mitigate specific PQ disturbances was researched, developed and implemented.

At first, a method for mitigation of frequency variations was introduced. These frequency variations are primarily caused by the fluctuating power feed-in of the intermittent renewable power sources. Since wind farms play an increasingly important role in European power systems, the rotational energy stored in wind energy conversion system (WECS) was utilized to mitigate the frequency variations. The proposed mitigation method was implemented by modifying the WECS control without the need of supplementary hardware. Besides its ability to mitigate the frequency variations, the proposed mitigation method focused on maintaining a high wind energy capture and on ensuring the stable operation of WECS. The method was able to keep the frequency variations within a narrow band by smoothening the output power of WECS. The mitigation of the frequency variations was achieved with only minimal power losses due to the slight deviation from the maximum power point. The method was able to keep the frequency variations within a narrow band. This was proven by simulation of the Irish power systems at a high penetration of system non-synchronous penetration of 90 %. The simulation results also showed that the implementation of the proposed mitigation method significantly reduced the fluctuations of the active power feed-in of wind farms. Consequently, the fossil fuel power plants are expected to provide less balancing energy to keep the power balance in the system. Thus, the proposed mitigation method can be used as part of balancing services.

The further part of the document focused on the harmonic aspect of PQ. To mitigate the harmonic distortions, in the PE rich power networks, two approaches were taken. The first approach focused on reducing the harmonic emissions of PE devices through device-based mitigation methods while the second addressed the harmonic distortions through system-wise mitigation techniques.

The most appropriate device-based harmonic mitigation solutions in modern PE-based devices were presented. The PE-based devices considered were the Statcom, photovoltaic plants, and the Static Var Compensator (SVC). Firstly, a self-compensation harmonic mitigation solution was implemented with Statcom device by adding several harmonic control loops to the existing fundamental component vector controller. The added functionality decreased Statcom’s current harmonics emission significantly. To interface photovoltaic to the grid, a price-performance study concluded that the LCL-filters are a better alternative to first-order inductive filters. Regarding the SVC, a procedure for designing passive filters by selecting the frequencies to be tuned was explained.

A novel optimization concept of system-wide harmonic mitigation was introduced as a promising solution. The concept involved different mitigation strategies including the placement of passive
filters at harmonic propagation points in the network as well as the PE-device based mitigation strategies. The optimal mitigation solution, zonally and globally, was identified through the proposed techno-economic optimisation technique. Both device-based and central harmonic mitigation strategies were realized through optimization. To address the variability of operating conditions during a year, a set of representative operating conditions were selected based on a clustering approach. Based on the techno-economic optimisation concept, it was found that the central harmonic mitigation is the most adequate solution. The central harmonic mitigation method was able to bring harmonic performance well under the thresholds and greatly reduce the cost caused by the harmonics. As an alternative to the optimization based harmonic mitigation method, a probabilistic methodology that determines the most effective locations for installing passive filters is offered. The probabilistic methodology is more suited to large networks than the optimization method as determined by the computational effort. However, the performance of the probabilistic approach with reference to harmonic mitigation might not be as optimal as that of the techno-economical optimisation method.

Beside the proposed mitigation methods, a questionnaire was composed and distributed to MIGRATE partners and to other European transmission system operators (TSOs) in order to obtain information on PQ related legislative aspects. Based on the results it has been possible to understand how TSOs in Europe deal with allocation of headroom for different customers and how system level PQ management has been coordinated within and between different systems. In general, it can be concluded that PQ coordination and legislation is somewhat limited in current systems. Therefore, it is recommended to form either ENTSO-E or CIGRE/CIRED working groups to harmonize the PQ management approaches and to unify the PQ legislation in the respective Grid Codes and legislative documents. This will enable more coordinated allocation of power quality headroom for different customers, minimize possible future costs related to power quality mitigation and guarantee optimal system development.
Appendix A

Table 7-1: Reduction factors for Statcom device. Reduction factor is calculated as a ratio of individual harmonic values with and without the self-compensation algorithm.

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<th>U=1.05 Ih [%]</th>
<th>U=1.1 Ih [%]</th>
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Table 7-2: Reduction factors for PV device. Reduction factor is calculated as a ratio of individual harmonic values for $L$-filter and $LCL$-filter.

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Table 7-3: Reduction factors for SVC device. Reduction factor is calculated as a ratio of individual harmonic values for initial case and the case, with the proposed passive filters design.

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Appendix B

Discussion on harmonic mitigation options:

- **Harmonic mitigation by optimal collaboration of DGs and filters**

  References [147]-[155] study the penetration levels of DGs alongside the deployment of corrective measures for harmonic mitigation; these corrective measures include filters, FACTS devices and DGs themselves since they are also capable of PQ improvement.

  In references [147],[148], optimisation of the parameters R-L-C of PPF connected in a wind farm is performed, the proposed method ensuring the PPF cost is the most economical, the DG penetration power is the largest and the THD is the smallest. Specifically, the OF minimises the cost of the PPF and the THD, maximising at the same time the amount of reactive power provided by the filters (PPF). Hence a multi objective optimisation is developed. The location of the filter is not formulation, only its size/parameters, though the method could be extended. A Genetic Algorithm (GA) is used for the multi-objective optimisation.

  In reference [149] the location of wind generators and EV in distribution systems is analysed. The idea is that the wind generators can be utilised to subside the effect of EVs on harmonic distortion. Hence, the integration of wind generators is able to reduce the negative effect of EVs on harmonics. Optimal sizes of wind generator are calculated using a Genetic Algorithm in a test feeder to reduce voltage and current THDs below the IEEE 519 recommended values. Hence, the corrective measure here would be the wind generators themselves. With respect to the OF, there are actually two, minimization of the cumulative voltage THD and cumulative current THD. The cumulative THDs account for the sum of the voltage or current THDs at each node and phase of the distribution circuit. In this case the OF is actually comprised of only PQ features.

  In reference [150], it is proposed that a hybrid framework with a heuristic optimization algorithm for the planning and allocation of DGs and FACTS devices considering collective grid constraints, such as voltage harmonics constraints, power balance constraints, voltage regulation constraints and over-current relay constraints, can be conceived to maximise the DG penetration levels, inverter based and conventional. The overcurrent and relay constraints are related to the conventional DGs while the harmonic constraints with the power electronic based DGs. A simple genetic algorithm is used here to solve the proposed hybrid approach non-convex optimisation problem and test its efficacy. The FACTS devices studied are SVCs and TCSCs.

  In reference [151], the focus is on the placement and sizing of STATCOM units as well as the evaluation of their performances using particle swarm optimization (PSO) to improve voltage profiles of highly distorted distribution systems. The total size of STATCOMs connected to the network depends on the harmonic order. The OF for the optimal siting and sizing of STATCOMs minimise their sizes. The constraints included are the lower Vrms for each bus according to Australian standards.
In reference [152], the integrated reactive power optimization of photovoltaic power and capacitors is proposed. The objective function minimizes the sum of the expected values of the fundamental loss, the penalty term of fundamental bus voltages, and the penalty term of voltage THDs. Meanwhile, chance constraints were put on fundamental bus voltages and voltage THDs, which considered the uncertainty of photovoltaic power. Finally, GA was applied. Hence this is a probabilistic approach. The shunt capacitors are not sized or optimally located (fixed), but only the reactive power of PVs. The size of capacitors is already fixed, it only defines the number of banks. The corrective measure in this case is the reactive dispatch of the PVs, step size of capacitors banks, tap changer position of transformers and generator voltages.

In reference [153], the focus is on the description of the provision of differentiated PQ levels via the construction of tailored optimisation objectives and the development of a mitigation strategy/solution to facilitate the provision of differentiated PQ levels for given zones and zonal thresholds. Based on the analysis of PQ performance of the network and the sensitivity of PQ performance to the injection of active/reactive power, a set of potential locations is selected globally and zonally, and made available initially for the placement of various FACTS devices. Given the objective function based on gap indices, a greedy algorithm is applied. The optimisation problem is to minimise the gap between the received PQ performance and the zonal thresholds. Five new indices are proposed, three focused and two that take into account all the first three within the optimisation problem so that all of them are attacked at the same time. It is suggested that in PQ mitigation planning, it is more appropriate to consider the related critical phenomena simultaneously. A comparison of the greedy algorithm and the Genetic Algorithm is performed, the greedy algorithm is better adapted to the formulation proposed in this work, and is also very straightforward to implement. This is also a probabilistic approach, as several uncertainties are considered when defining the case scenarios for analysis.

In reference [154], a partition control strategy driven by the disturbance data of nodes, which is used to allocate APFs to individually or simultaneously suppress harmonic distortion and voltage unbalance in distribution networks, is introduced. Trend features, disturbance severities, and subsection lengths are used to establish a parameter matrix as the pattern representation of disturbance time series (DTS). A feature distance (FD) method is developed to implement pattern matching to measure the coupling degrees of single or integrated disturbance among nodes. APFs are allocated in the identified areas in accordance with the coupling degrees. The proposed strategy can achieve controls for harmonic distortion and voltage unbalance in the entire distribution network. This procedure is not strictly optimisation, but a data driven approach, and it does not include optimal location and sizing of DGs. Its generality may make it applicable to larger transmission systems.

In reference [155], a control architecture is proposed to ensure collaboration between APFs and DGs in harmonic mitigation. In this control, the harmonic compensation burden is placed on DGs rather than on the APF. In other words, APFs “start to collaborate” with DGs (the DGs equipped with active damping of harmonics) once all the DGs are operated at full power output. In this way, the rate of in-operation APFs reduces as far as possible. It is noteworthy that the DGs’ rated power is considered in the collaboration so they never become overloaded.
**Harmonic mitigation by optimal sizing, penetration and allocation of DGs**

References [156]-[166] focus only on the optimal location and sizing of the DG, so that this optimal location ensures that PQ issues are not encountered in the network. In reference [156], the DG allocation and sizing is done considering voltage profile improvement, loss reduction, and THD reduction in distribution networks. Particle Swarm Optimization (PSO) is used as the solving tool. This paper focuses more on the optimisation algorithm rather than the power system problem that is solving. The goals are loss reduction, voltage profile improvement, THD reduction, and DG cost reduction. The voltage profile improvement is based on THD reduction, based on maximum tolerances. The factors are weighted by appropriate heuristic penalty factors.

In reference [157] the impact of the DG penetration level and location is evaluated by considering the power quality limits of IEEE Standard 519-1992. The nonlinear optimization problem is formulated with the size of the DG being a positive real number to be optimized and solved using particle swarm optimization. The maximization of DG capacity is the main objective in the OF, while satisfying the voltage limits, THD and IHD limits. The THD is integrated as a constraint in the formulation.

In reference [158], a probabilistic planning approach is proposed for optimally allocating different types of DG into a harmonic polluted distribution system so as to minimise the annual energy losses and reduce the harmonic distortions. The OF is the total system annual power loss. The constraints include voltage limits at different buses of the system, feeder capacity, THD limits and maximum penetration limit of DG units. The optimisation process is achieved using the GA optimisation method. It is stated that GA presents some advantages with respect to other algorithms, such as: it has a high probability finding the global optimum because of the usage of several design points, the derivative of fitting function is not needed, the value of it is only used for optimisation and the GA procedure can be applied on both discrete and integer programming problems. The methodology is based on generating a probabilistic generation load model that combines all possible operating conditions of the DG units with their probabilities, hence accommodating this model in a deterministic planning problem.

In reference [159], the proposed optimisation determines the maximum DG penetration level by optimally selecting types, locations and sizes of utility owned DG units. The DG penetration level could be limited by harmonic distortion as well as protection coordination constraints because of the variation in fault current caused by synchronous-based DG units. Hence the objective of the proposed problem is to maximize DG penetration levels from both types of DG unit, taking into account power balance constraints, bus voltage limits, total and individual harmonic distortion limits specified by the IEEE-519 standard, over-current relay operating time limits, and protection coordination constraints. The DG penetration study is formulated as a nonlinear programming (NLP) problem solved by means of PSO. The constraints of the proposed problem include fundamental frequency
real and reactive power balance, RMS voltage limits, individual and total voltage harmonic limits at each bus, relay operating time limits and protection coordination constraints.

In reference [160], the maximum DG penetration level is determined taking into consideration the IEEE 519 allowable voltage harmonic limits. The proposed study is formulated as a mixed integer non-linear programming (MINLP) problem. The maximum DG penetration level based on optimal DG size and location is determined using particle swarm optimization (PSO) algorithm. The results show that by decentralizing the DG capacity, higher penetration levels could be achieved. The OF is the maximisation of DG, calculated in terms of the total system capacity. THD and IHD are included as constraints in the formulation. The GA and PSO are tested for solving the optimisation problem, the performances are nearly equal, with a slight advantage to the PSO in terms of time, so the PSO is the final option chosen.

In reference [161], the optimisation (minimisation) of the voltage sag and harmonic distortion is performed. A composite, constrained objective function is put forward by considering objectives such as the cost of the power losses, the cost of the DGs and the cost of loss of load because of the voltage sag and the constraints such as line flow limits, number/size of the installed DGs and the power quality limits of the standard IEEE-519. A Genetic algorithm is used to solve the optimisation problem, though a comparative performance analysis of various metaheuristic optimisation techniques is also presented. The OF is divided into three, minimisation of losses, minimisation of voltage sag and total cost of DGs. The harmonic limits (THD) are included as constraints. The final OF is formed using a well-known weighting method for each individual objective with a penalty function approach.

In reference [162], a two-phase approach for maximizing the penetration of the DGs complying with the collective grid constraints such as voltage harmonics and relay coordination limits is used. The two phase approach is solved using two different optimization algorithms namely the GA and the differential evolution (DE) considering various constraints. In phase 1 analysis, the harmonic power flow is conducted and voltage output penalty is calculated and in phase 2 analysis, penalties are calculated based on the optimal coordination of the overcurrent relays. The fitness function optimises the MVA of the inverter and synchronous based DGs. The GA method has the advantage of dealing with discrete variables whereas the DE method has the advantage of dealing with the continuous variables. Therefore, both algorithms are tested to evaluate their performance. It is established that the GA outperforms the DE algorithm.

In reference [163], four aspects are sought: active power loss, harmonic distortion, voltage quality and voltage sag, hence four separated OFs are defined. Comprehensively the merits and faults of three algorithms are compared on application of solving DG locating and sizing problems, and this paper finally proposes an improved particle swarm optimization. The innovation point of this paper is to introduce two economic indicators transformed by two power quality indicators (harmonic distortion and voltage sag) into objective function to give a more comprehensive analysis. This uses probabilistic fault modelling and the Monte Carlo method for multiple random fault simulation of various random factors that affect failures (e.g., probability distribution model of fault type, faulted line, fault location, fault duration and protection operation time), and counts characteristic values of voltage sags.
In reference [164], an approach to sizing of renewable energy plant and storage system using particle-swarm optimization is proposed. The aim is to support the hosting capacity of the network where the unit is connected. The main original idea of this contribution is that sizing of renewable energy plant should be done together with supporting storage system. The OF though, just optimises the amount of size along the RES plants, and in that way helping the network against harmonics but indirectly, it does not include harmonics in the OF or constraints.

In reference [165], a methodology is suggested which only uses load flow results to determine the best DG location. This paper discusses various approaches for placing DGs. It proposes the minimisation of losses, with the secondary objective of reducing the harmonics and fault contributions in the power system. It does not strictly follow an optimisation approach but an iterative one to achieve the goal, based on indices per bus.

In reference [166], the DG penetration is analysed from two constrains: voltage distortion and current distortion. This study investigates the influence of the DG and load distribution position on the voltage distortion of a feeder. The formula for calculating the penetration under the worst conditions considering the current distortion limit is deduced. Then a validation method is proposed based on random scenarios and heuristic optimisation to demonstrate the deduction above. These rules obtained by feeder are highly adaptive and can effectively guide DG integration and operation. Random scenarios are created, then heuristic optimisation is applied to calculate the penetration levels considering the different distortion limits. No details about the optimisation procedure are provided.

Based on the literature review presented above it can be seen that the potential harmonic issues in networks with DGs have been usually prevented/minimized by optimally selecting the type, size and location of DGs, while meeting international standards, minimizing the loss, or maximizing the DG capacity and penetration level. These problems have been modeled as optimization problems, such as NLP or MINLP, and they have been solved by the appropriate optimization algorithms. The optimization algorithms that were typically selected for harmonic mitigation, in combination with harmonic load flow study, included non-linear programming and evolutionary algorithms (such as particle swarm optimization and genetic algorithms).

- **Market based Harmonic Mitigation**

References [167]-[169] approach the problem of harmonic mitigation by applying a market type optimisation procedure. The methods do not look to deploy corrective measures for harmonic mitigation or sizing and locating RES based DGs to ensure PQ, but use the existing DG assets for that objective, using optimisation methods, hence being relevant for the subject of this report.

In reference [167], the focus is on PQ improvement in distributed electricity systems operating in accordance with electricity market rules. The inverters are fully controlled and can operate as current sources providing not only reactive power but also compensating the asymmetry and harmonic distortion. The paper presents the rules by which by adequate optimisation and control, an operator is able to balance electric energy and improve PQ using the converters capabilities as ancillary
services. The method uses sequence network parameters to measure asymmetries. It uses a classic optimisation procedure for the solution of the problem, since it includes dispatch with its associated constraints, though it does not detail the procedure. The OF is comprised of costs and consists of three major parts according to the active and reactive power balancing, asymmetry balancing and harmonics reduction. Penalty factors are associated with THD and voltage deviations. To calculate the amount of ancillary services needed, the optimisation is done for a 24-hour period. It discusses several options for optimisation and some rules or OF types for this kind of problem, without going into much detail.

In reference [168], the focus is on the optimal operation of the DG, particularly the RES, so that technical standards of PQ should be maintained. The optimization can be carried out using the concept of local energy balancing and ancillary services provided by the DG and RES. It is stated and shown in the paper that RES DGs are able to ensure the development of local energy resources preserving the technical standards of network operation. The technical novelty of this paper is the implementation of the local energy balancing system in the low-voltage distribution system using competitive electricity market rules and the application of nonlinear programming for overall optimization. The proposal presented includes economic dispatch and optimization of ancillary services, taking into account the compensation of reactive power, harmonics, and asymmetry. The key message is that it is possible to use local energy resources connected to LV networks more widely, preserving technical constraints of network operation, implementing liberalized electricity market rules. The objective function is a cost function, and it represents the costs of local energy balancing and the costs of ancillary services in three components: reactive power compensation, asymmetry reduction, and harmonic mitigation. Here the THD cost reduction is included in the OF. The OF presented is quadratic due to power losses and reactive power. Moreover, the function is not smooth because price bids are submitted as stepwise functions. For DNs, unit commitment can be neglected as new DG units are fast reacting and easily controllable. Therefore, nonlinear programming is sufficient for this application. Hence, the active-set algorithm, which represents Sequential Quadratic Programming (SQP) where subsequent steps during iterations are calculated by solving quadratic sub problems, is used. It is stated that for large DNs, mixed-integer and linear programming can deliver the results in shorter time periods. However, it would require the application of linearization, which, as a consequence, would introduce many model simplifications. It is stated that the solution proposed in the study is coherent with competitive market rules as the same mechanism as currently implemented in transmission networks. Therefore, the method applied here could be easily extended to the transmission network.

In reference [169], no harmonic mitigation is actually analysed, however, it investigates how offshore wind power generation would not be capable of accounting for all the total load demand due to the presence of harmonics in the power electronics converters from offshore wind farms. These harmonics in offshore wind farms have a negative influence on the total power generated from offshore. It is relevant because the method calculates the optimal schedule from offshore WF considering harmonic losses and locational marginal prices, and the model is a function of harmonics resulting from a large penetration of offshore wind power into a grid. Results reveal that the increase
of harmonic power losses causes an increase in nodal marginal prices. The optimisation problem is a mixed integer nonlinear programming (MINLP) type and the OF minimises the harmonic active power loss and locational marginal prices as a function of harmonics in the network, while satisfying a set of constraints. Both objectives in the OF have weighting factors. The Locational Marginal Price (LMP) used in this formulation is defined as a function of harmonics at each node. The solution of the optimisation problem is done through a conventional method, though little detail is provided.

Instead of optimally selecting the size and location of DGs for harmonic mitigation, as discussed in the previous section, DG operation and ancillary services (such as the inverter capability) can be also used to mitigate harmonics or at least to maintain certain harmonic performance level. The related operation and coordination can be implemented via electricity market. This provides an innovative alternative approach to mitigate harmonics.
References


[137] O. P. S. Data, "https://open-power-system-data.org/."


