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Flexible Operation of Electric Power Transmission Grids

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Additional information is available at the end of the chapter

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Abstract

In order to reduce carbon emissions and increase sustainability many countries in the world are switching to renewable sources of energy for electricity production. European Commission has set targets for its Member States to reduce such emissions and proposed share of renewables of around 30% in gross final energy consumption by 2030. Moreover, the electricity market is decentralized in Europe. As a result of decentralization and increased renewable penetration into the system, Transmission System Operators (TSOs) are faced with new challenges to operate their system securely. Some of the means of congestion management by the TSOs have become costly after decentralization. Moreover, variability associated with renewables can create congestion in a distant grid location which belongs to another TSO. Hence, TSOs are forced to find alternatives to operate their systems securely and in a cost effective manner. Inter-TSO coordination is one such non-costly alternative which requires increasing attention when more renewables are integrated into the system. The coordination (preventively and/or curatively) will help to operate the existing transmission grids more flexibly when more renewables integration demands transmission expansion, which is severely limited in Europe.

Keywords: FACTS, HVDC, TSO, preventive control, corrective control, system security, renewable energy

1. Introduction

Before the mid-1990s, the operation of power system in Europe¹ was quite straightforward as a single entity was responsible for generation, transmission, and distribution of electric power. That single entity was responsible for the safe system operation for all timeframes at a

¹ The prime focus is laid on European power system.

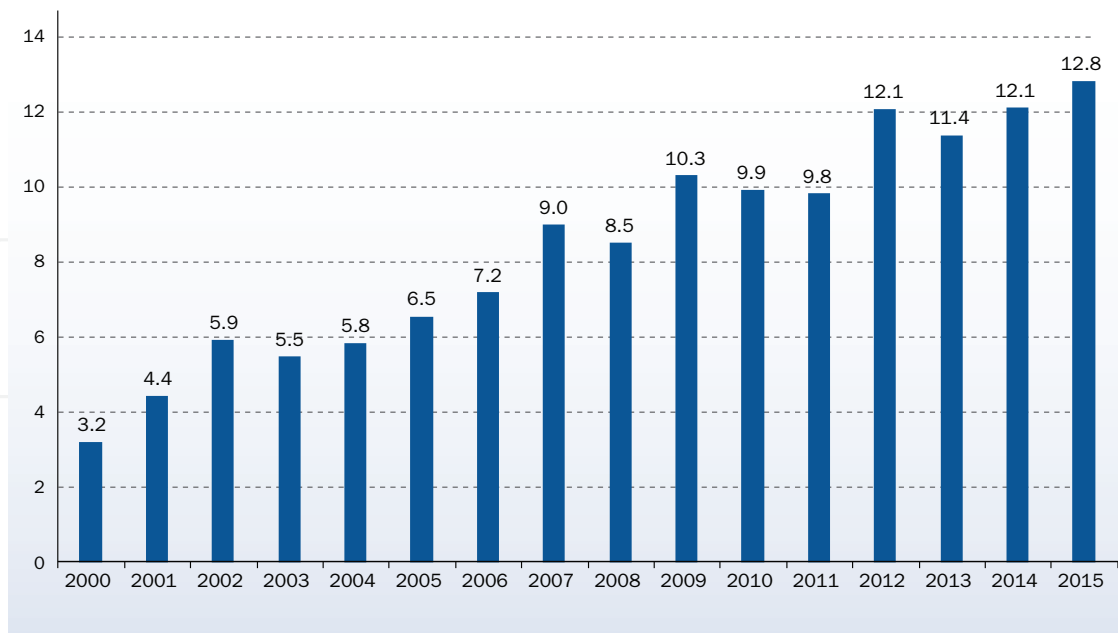
minimum cost possible. In order to increase market competition, the power system was decentralized/unbundled/liberalized in the mid-1990s with different market players responsible for system operation. The entity responsible for power transmission is the so-called transmission system operator (TSO). This stakeholder is now responsible for the efficient and secure operation of the power system.

The TSOs are facing increasing challenges in planning and operation of their systems, especially after decentralization and increased penetration of renewables. Before unbundling, the TSOs have direct control over generation unit redispatch and managing power flows through their systems (line and busbar switchings, capacitor switching, etc.) in order to resolve system congestion. The investment decisions on both generation and grid expansion were rather coordinated, with the generation planned close to the load centers. After decentralization, the TSO still makes the investment decisions, but the decisions in investments regarding generation expansion are not coordinated with the decisions regarding grid expansion. As a result, the new generators are located closer to the energy source.

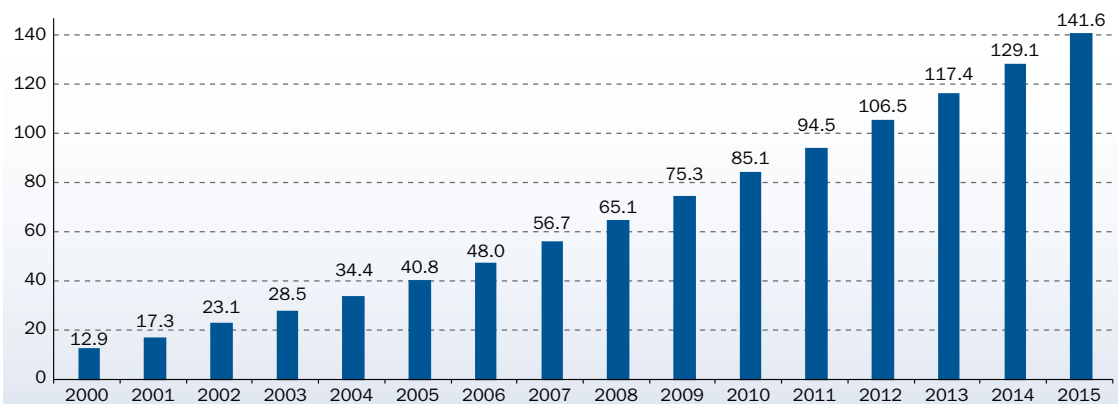
The European Commission (EC) has undertaken significant measures to reduce carbon footprint of Continental Europe, by setting targets such as 2020, 2030, and 2050 [1]. The electrical energy sector is seen as a significant contributor for reducing carbon emissions because of (in general) the concentrated emissions and the availability of potential alternatives. Solar and wind are such suitable alternatives amongst other nonconventional sources of energy. A significant amount of wind energy sources is installed in Continental Europe. **Figure 1** shows the installation trend of wind integration in Europe.

Annual wind power installations in the EU have increased steadily over the past 15 years from 3.2 GW in 2000 to 12.8 GW in 2015 (**Figure 1a**), with a compound annual growth rate of 9%. 141.6 GW of wind is installed in the EU in 2015. In this year, it has achieved a record growth rate of 9.7% (**Figure 1b**). Germany has the highest number of wind installations in the world. The other countries that follow Germany in terms of wind installed capacities are Spain, the United Kingdom, France, and Italy. Eleven other EU countries have over 1 GW of installed capacity [2].

These renewable energy sources are highly variable in nature. More installations of these generation sources and their integration with the existing transmission system lead to higher variability within the system, as the variable injections from these renewables lead to variable power flows in the system, and more balancing actions in the electricity market are required to cope with this variability of these generation sources. At the European level, the best locations for wind farms are mostly onshore and offshore, whereas the best locations for solar generation are southern Europe. As these generation sites are far away from load centers, a transmission network expansion is required, as the existing network is limited to cope with the variability of these power flows [3]. However, major investments in the transmission system expansion have been lacking due to heavy siting opposition [4].



(a) Annual



(b) Cumulative

Figure 1. Wind power installations in EU (GW) [2].

The changes, both in unbundling of the electricity sector and increased integration of renewables, have triggered a renewed interest in flexible alternating current transmission system (FACTS) devices, and especially in power flow controlling devices (PFCs) such as phase shifting transformers (PSTs) and High voltage direct current (HVDC). Several of these PFCs are installed in the European power system. FACTS devices, in general, are capable of controlling power flows [5–9], improving voltage stability [10–12] and small signal stability [13, 14], and damping power system oscillations [15–18].

Severe limitations for transmission expansion in Europe and the push towards integrating more renewables into the system lead to more stress on the existing grid. The only alternative that remains under those circumstances is to use the existing grid more flexibly and effectively with the help of already installed PFCs in the system. However, those devices need to be

controlled in a coordinated manner among the TSOs in order to achieve a common objective, that is a system-based objective rather than individual-based.²

This chapter describes different activities that are involved in power system operation in Europe, especially in Central Western Europe (CWE³), starting from 2 days ahead of real-time operation and ending at real time. It also shows the effect of coordination among TSOs with respect to PFC operations that help to manage the system in an efficient way and increase more carbon-free generation sources into the system.

2. Power flow control and PFCs

For a lossless transmission line ($R_L = 0$) connected between buses “s” and “r”, the active (P_L) and reactive (Q_L) power flows can be represented as [19]:

$$P_L = \frac{V_s V_r}{X_L} \sin(\theta_s - \theta_r) \quad (1a)$$

$$Q_L = \frac{V_s^2}{X_L} - \frac{V_s V_r}{X_L} \cos(\theta_s - \theta_r) \quad (1b)$$

where V_s and V_r are the bus voltage magnitudes of buses “s” and “r”, respectively, θ_s and θ_r are the bus voltage angles of buses “s” and “r”, respectively and X_L is the reactance of the transmission line. Both the active and reactive power are functions of four variables: line reactance, bus voltages at the two ends of the transmission line, and phase angle. In a meshed grid, line flows can be altered by changing any of those parameters. FACTS devices [6] are suitable means of altering those variables.

All PFCs are based on a switching technology in one way or the other. Based on different technologies used for switching, a classification can be made [20].

- The conventional devices use mechanical switching. Hence, these devices are not suitable for controlling system dynamics as they are relatively slow in operation. However, there are clear advantages of this technology, such as simplicity, relatively low cost, and high reliability [19].
- Thyristor-based devices can switch within a few periods of the mains frequency. However, they are line commutated devices, which limit their multiple switching operations within

² Controlling PFCs individually by a TSO can have a significant impact on its neighboring grid, as the European system is highly meshed and interconnected.

³ A region consisting of Belgium, France, Luxembourg, Germany (Amprion, Tennet TSO GmbH and Transnet BW) and the Netherlands.

one half of the line voltage [21]. Classical high voltage direct current (HVDC) schemes employ such devices [19].

- Voltage source converters (VSCs) are relatively new type of converters that employ faster switching components. Pulse width modulation (PWM) schemes are used to control such devices. Such schemes are possible especially due to the latest advancements in solid-state components such as insulated gate bipolar transistors (IGBTs) [22]. VSCs are expensive, due to the high voltages used in the transmission system. The high switching frequency causes higher losses. However, new converter topologies, modulation techniques, and power electronic devices currently lowered the high switching frequency losses [19].

One such PFC is a so-called PST. The possibility of controlling the power flow by PSTs was already recognized long time ago, with the earliest applications more than 70 years before. PSTs are used to track slow load variations, in a timeframe of minutes to hours. Furthermore, they are used to redistribute line flows in systems with unequal loading on parallel paths. The PST inserts a voltage in the transmission line so that the phase angle between sending and receiving end voltages can be controlled. The basic operating principles for PSTs are ordinary transformer technology combined with on-load tap changers (OLTC). The phase angle shift is created by inserting a voltage in quadrature to the phase voltage. In ordinary three-phase systems, this quadrature voltage can be obtained as the line voltage between other phases. PSTs are also referred to as quadrature boosters. They are quite slow, but ideally suited to control power flow in the transmission system, e.g., to avoid overloading of critical lines or to counteract loop flows. Recently, a significant number of PSTs have been installed in continental Europe.

PSTs can be classified into direct/indirect and asymmetrical/symmetrical. A detailed description of these can be found in Ref. [19].

As stated in Section 1, the European TSOs are facing challenges to operate their systems securely. This is mainly due to the fact that increased penetration of renewable energy in one control area⁴ of a TSO during real time can be significantly different than forecasted leading to congestion in the control area of another TSO, as the areas are highly meshed and interconnected. A typical example is shown in **Figure 2**. It is evident from the figure that approximately 7.4 GW of additional wind energy is injected into the system during real time at the 19th hour compared to that of the forecasted value. This extra injection created severe congestion in Dutch and Belgian transmission systems, which acted as an alternative path for the energy to reach the French system. This type of scenario will increase in the future with increased integration of renewables. There will be several such scenarios in the future in which a single TSO will not be able to solve problems in its own control area due to factors originating in another control area. In such cases, coordination will be a key aspect to address such problems.

⁴ The area in which a TSO is solely responsible for power system security management. These areas are generally the geographic borders of the countries, exceptions being Germany and Luxembourg.

In order to understand the increased necessity of inter-TSO coordination in the future, it is necessary to understand the operation of European power system starting from 2 days ahead till close to real-time. The focus lies on the functioning of the system from a TSO perspective.

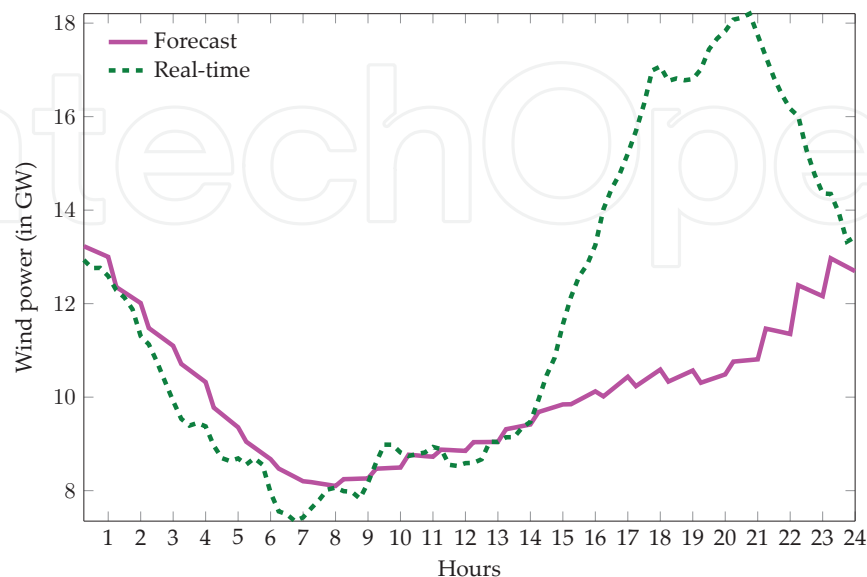


Figure 2. Wind power in Germany on January 19, 2012 [4].

3. Power system operation in Europe

The planning of power system in Europe during real time starts 2 days ahead of real time.

3.1. D-2

“D-2” represents 2 days ahead of real-time operation. The main activity that takes place at this timeframe is to assess cross-border capacities across the borders of interconnected countries. These cross-border capacities are then allocated to the day-ahead market. This process starts with defining an initial grid situation called basecase.⁵ The physical margins available on the basecase situation are identified and additional exchanges are calculated and made available after the capacity calculation. The calculated results from the previous process are then validated by security engineers and involves:

- Taking into account the uncertainties that are not considered in the previous stage.
- Taking into account the operational limits, such as voltage limits. These limits are not taken into account in the calculation stage, due to the linearized problem.⁶

⁵ It includes planned outages of network elements but does not include loss of network elements.

⁶ DC approach is used for the calculation.

- Proposing corrections for the approximations made during the calculations.

The accuracy of this process depends on the availability of reliable information of the network of each TSO, including expected generation and load patterns and the corresponding buses at which they take place. Currently, flow-based capacity assessment is performed in the CWE region of Europe.

Detailed information about the activities at this timeframe can be found in Ref. [4].

3.2. D-1

“D-1” represents 1 day ahead of real-time operation. The electricity market is cleared at each power exchange (PE) of individual countries depending on the supply and demand bids and respecting the allocated cross-border capacities at each border assigned by the respective TSOs during D-2 system operation. The generation companies at each country optimize their generation portfolios that would meet the system demand with least possible cost (also termed as economic dispatch). The exact system bus injections are the outcome of it. These data are then provided to the TSOs to check the feasibility of the economic dispatch, as it does not consider the network topology. The TSOs perform security analyses of their respective control areas according to the contingency list. As part of standard operating practices, outages of all elements of the interconnected system at the level of 380/400 kV and above are considered as contingencies. Moreover, all outages of elements at the lower voltage levels of the interconnected system (220/150 kV) having significant influence on the security of the interconnected system operation are also considered as contingencies. Contingencies are of three types: normal, exceptional, and out-of-range. TSOs generally consider normal and exceptional contingencies in their contingency lists in order to check system security.

Each TSO prepares its contingency list consisting of all internal normal and exceptional contingencies considered relevant according to the risk management of the TSO. The risk management currently considered at the European level is “N⁷-k” criterion. The status of the control area of a TSO is reflected by it after an event defined in the contingency list. The N situation already includes L elements in outage. The N-k simulation considers those L elements as already out of operation and simulates the loss of k elements (these k elements are out of operation due to occurrence of an event defined in the contingency list) resulting in N-k state. Generally speaking, k is taken to be 1.

Any event in the contingency list must not endanger the security of the interconnected system operation. The operational condition within the control area of the TSO must not lead to triggering in an uncontrolled cascading outage propagating across the borders after an event. In order to prevent such cascading effects with impact outside the borders, each TSO launches N-1 security calculations, the aim of which is to become aware of the consequences of trips of network elements and to prepare adequate remedial actions (RAs) for managing such contingencies. The goal of RAs is to fully respect the N-1 principle taking inter-TSO coordi-

⁷ It is also called basecase situation and is defined as the status of the control area of the TSO that includes outages but not contingencies. This situation takes into account all forecasted outages and known damages of network elements.

nation into account. The RAs must make sure that the principle of “no cascading with impact outside my borders” is respected at all times. The RAs are prepared at this timeframe by numerical simulations and to be duly applied in D timeframe. Mainly two types of RAs are considered by the TSOs: preventive and corrective.

3.2.1. Preventive RAs

Preventive RAs are a set of actions that are taken by the TSOs in anticipation to a need that may arise due to the lack of certainty to cope efficiently and in due time with the resulting constraints once they occur. With preventive RAs implemented, no immediate action is required when a contingency occurs, and the operator can slowly alter the grid parameters and topology to the next calculated optimal state including new security measures if the postcontingency state requires so. They are the first stage decisions, as grid security is the main objective [23].

3.2.2. Corrective RAs

Corrective actions are another set of measures that require immediate action of the operators to rapidly relieve the constraints with an implementation time delay for full effectiveness compatible with temporary admissible transmission loading (TATL⁸). These actions are implemented after the occurrence of the event. Before the event occurs, a screening of the possible contingencies and their required control actions is performed. Generally, outages of generators fall under this category. They are called second stage decisions [23].

When corrective actions are not sufficiently rapid, preventive RAs are implemented before the occurrence of the related contingency. The TSOs inform their neighboring TSOs if the corresponding RAs influence their neighbors in order to prevent countereffects on neighboring TSOs.

3.2.3. Multistaged decisions

The synchronous interconnection of the national grids of different countries in Europe in order to increase security of supply also has disadvantages with respect to managing the power system as the larger geographical regions need to be taken into account for security analyses. In such occasions, single contingency surveys seem inappropriate. The risk of cascading outages needs to be taken into account, which may lead to a partial or complete blackout. This may happen due to an unfortunate set of strategic outages and incidents, combined with unexpected injection patterns. In such cases, grid operators undertake multiple actions within a very short time. A series of decisions are undertaken to avoid the system to end up in a dangerous state [23].

In order to carry out load flow forecasts and to prepare RAs during this operational phase at D-1, it is necessary to exchange relevant data among the TSOs. This process of congestion forecasting is called day-ahead congestion forecast (DACF) procedure and is based on the most

⁸ It is the loading in amperes, MVA or MW that can be accepted through a transmission line for a certain limited duration.

reliable network models exchanged by the TSOs. A total of 24 DACF files are prepared by each TSO in continental Europe, merged to form a single DACF file for each hour. Based on this merged file, contingency analyses are performed considering the designed contingency list of each TSO. Thus, a comprehensive 24-hour review of the security risks of the grid for the following day is generated. The RAs are then determined taking into account the severity of the constraints and the available time to relieve them.

3.3. Intraday and close to real-time (D)

At the day of actual operation, the basecase situation is determined by state estimation on the basis of measurements and topology. The scope of N-1 security calculations at this timeframe is:

1. Each TSO performs an automatic N-1 simulation systematically for all the contingencies inside the contingency list in order to detect potential constraints within the control area according to the risk policy of the TSO. Each of these simulations takes place with a periodicity of 15 minutes.
2. Each TSO performs an additional N-1 simulation to confirm the diagnosis of simulations performed in D-1, taking into account the new topology of the network. The efficiency of the remedies is mainly verified.
3. Each TSO also performs a new $\tilde{N} - 1$ security calculation in order to detect future constraints (a \tilde{N} is a situation after tripping an element. In other words, $\tilde{N} = N - 1 + \text{applied remedies}$). This analysis is carried out immediately after the RAs are implemented for the first N-1 event occurrence. Hence, a new set of RAs are prepared for the new constraints that may occur, including coordination among TSOs.

After the occurrence of the first contingency at this timeframe, the TSOs launch the already prepared RAs (prepared at D-1) without delay in order to keep the system secure, that is, new $N (= \tilde{N})$ is safe but new $\tilde{N} - 1$ may not be safe for the system. The impacted TSO, being then in a secure situation \tilde{N} launches security calculation to detect the risk and prepare new remedies. The TSO implements remedies with the minimum delay. If the RAs for a $\tilde{N} - 1$ are available and efficient in a short while the system is safe. Otherwise, the neighboring TSOs are informed about the delay in finding appropriate remedies and seeks help from them in order to avoid or reduce the delay. The system is prone to risk at this particular state. The study of new remedies must be done quickly as the system can be jeopardized after the contingency if no remedies are identified. However, the delay cannot be estimated as it depends on the available remaining facilities of the power system. During such situation, the impacted TSO is in "Alert" state and provides the necessary information to its neighbors and searches convenient RAs with them.

Both at D-1 and D timeframes the regional coordination eases and enhances the search of (possible, but may or may not be optimized) coordinated solutions in case of a call for help. Coordination is done to decide on a convenient set of RAs in case best efforts by the impacted TSO to be implemented at first are not sufficient. Regional coordination enhances the chance

to find optimized/nonoptimized remedies and to prepare procedures or agreements for coordinated remedies. The general principle that is followed to relieve constraints by applying RAs is:

- First, the impacted TSO monitoring a constraint violation checks the implementation of internal RAs by itself.
- If the internal RAs are not efficient,⁹ appropriate RAs are decided in a coordinated manner with the neighboring TSOs.
- The prepared RAs are ready to be implemented in the control area where the contingency occurred or in the other control area(s) having significant impact.
- The RAs prepared with the help of regional coordination can involve other control area(s) having less impact.
- At this stage, specific analysis for costly measures taken by one or several TSOs to implement RAs is to be dealt within the framework of bilateral/multilateral TSO to TSO procedures.

4. Available means for RAs

The available means that are utilized by the TSOs for the RAs include costly and noncostly measures.

4.1. Noncostly measures

These remedial measures come at a zero cost to the TSOs. This is mainly due to the fact that these measures generally involve those assets which are owned and operated by them. Following measures are commonly undertaken by the TSOs:

1. Changing the topology of the system that includes some discrete actions on transmission devices. The most common practices within this action are transmission line switching [24–26] and substation busbar switching [24, 26].
2. Using FACTS devices.
3. Using HVDC that is owned and operated by the TSO.
4. Dynamic use of the existing transmission lines respecting their dynamic ratings rather than their static ratings. However, the prediction methods of the dynamic ratings must be reliable.
5. Inter-TSO coordination with respect to system operation.

⁹ Efficient means that the RAs are prepared with respect to the compromise between their effectiveness and their costs.

4.2. Costly measures

These measures come at a significant cost to the TSOs in a decentralized environment.

1. Redispatching generation within the control area of the TSO or a cross-border re-dispatch [27].
2. Using HVDC that is not owned by the TSO.
3. By employing demand-side management (DSM) measure [28], that involves lowering the demand of electricity. This measure is treated as a dispatchable resource and is called upon when needed.
4. Curtailing load in the system. This is not done by the TSOs in Europe for congestion management, and is done manually or automatically for underfrequency cases when sufficient generation or managing congestion is not possible.

Considering the current scenario in Europe with respect to renewables integration more flexibility in system operation and increased inter-TSO coordination will be required in the future. The flexibility can be achieved by a coordinated control of PFCs. Several of the PFCs are already installed in continental Europe mainly for five reasons:

1. Give more control options to the TSOs after decentralization.
2. Help to manage variable energy flows caused by increased cross-border trade and higher intermittent generation.
3. Improve reliability by interconnecting different regions and even different synchronous zones.
4. Offer firm capacity to the market through control.
5. In some cases they are the only feasible investment options.

5. Mathematical modeling to take coordinated control of PFCs into account

This section briefly describes the mathematical approach to consider PFCs in a coordination process. DC approach is adopted, as it works very well for the transmission system of Europe [29].

5.1. Modeling of PSTs in power flows

The DC modeling of PSTs is derived in this section [19].

5.1.1. Bus angle difference approach

If a single PST with phase shift α_{kj} is connected in series with the line between buses k and j , the power through that line is:

$$P_{kj} = B_{kj}(\theta_{kj} + \alpha_{kj}) \quad (2)$$

The DC power flow equations in matrix form can be represented as:

$$\Delta \mathbf{P} = [\mathbf{B}^T] \cdot [\Delta \theta] \quad (3)$$

Taking the phase shift into account, Eq. (3) becomes

$$\Delta \mathbf{P} = [\mathbf{B}^T] \cdot [\Delta \theta] + [\mathbf{B}_\alpha^T] \cdot \alpha_{kj} \quad (4)$$

where \mathbf{B}_α is a vector with value B_{kj} at position k , $-B_{kj}$ at position j , and zero elsewhere. Solving this matrix equation yields:

$$\Delta \theta = [\mathbf{B}^T]^{-1} \cdot (\Delta \mathbf{P} - [\mathbf{B}_\alpha^T] \cdot \alpha_{kj}) \quad (5)$$

Referring to the element (k,j) of the matrix $[\mathbf{B}^T]^{-1}$ as c_{kj} ; the angles θ_k and θ_j become:

$$\theta_k = c_{k1}\Delta P_1 + \dots + c_{kk}(\Delta P_k - B_{kj}\alpha_{kj}) + \dots + c_{kj}(\Delta P_j + B_{kj}\alpha_{kj}) + \dots + c_{k(n-1)}\Delta P_{n-1} \quad (6)$$

$$\theta_j = c_{j1}\Delta P_1 + \dots + c_{jk}(\Delta P_k - B_{kj}\alpha_{kj}) + \dots + c_{jj}(\Delta P_j + B_{kj}\alpha_{kj}) + \dots + c_{j(n-1)}\Delta P_{n-1} \quad (7)$$

Using the above two equations and considering $[\mathbf{B}^T]^{-1}$ is symmetrical, the angle difference is:

$$\theta_{kj} = \theta_k - \theta_j = \sum_{i=1}^{n-1} \Delta P_i (c_{ki} - c_{ji}) + B_{kj} \alpha_{kj} (2c_{kj} - c_{kk} - c_{jj}) \quad (8)$$

Combining Eqs. (2) and (8), the active power through line kj considering PST in that line is

$$P_{kj} = B_{ij} \left(\sum_{i=1}^{n-1} \Delta P_i (c_{ki} - c_{ji}) + \alpha_{kj} (B_{kj} (2c_{kj} - c_{kk} - c_{jj}) + 1) \right) \quad (9)$$

Hence, the power flow through line kj with an installed PST is obtained by adding weighted sum of the system power injections ΔP_i and a linear term in the phase shift angle α_{kj} .

Similarly, the power flow through a line pq can be represented as a function of the installed PST setting in line kj .

$$P_{pq} = B_{pq} \left(\sum_{i=1}^{n-1} \Delta P_i (c_{pi} - c_{qi}) + \alpha_{kj} B_{kj} (c_{pj} - c_{pk} + c_{qk} - c_{qj}) \right) \quad (10)$$

Though \mathbf{B}^T is a highly sparse matrix, $[\mathbf{B}^T]^{-1}$ is very dense. Hence, the linear term in α_{kj} in Eq. (10) is nonzero for every line, except for the radial ones. This suggests that the PST has an influence over the entire network. However, the influence can be very small for distant lines.

5.1.2. PSDF approach

Phase shifter distribution factors (PSDF) can be defined as a change in the line real-power flow with respect to a change in the PST angle [30]:

$$\text{PSDF} = \frac{\Delta P_{kj}}{\Delta \alpha_{pq}} \quad (11)$$

From Eqs. (9) and (10), PSDFs can be derived as:

$$v_{kj}^{kj} = \frac{\partial P_{kj}}{\partial \alpha_{kj}} = B_{kj} (1 + B_{kj} (2c_{kj} - c_{kk} - c_{jj})) \quad (12)$$

$$v_{kj}^{pq} = \frac{\partial P_{pq}}{\partial \alpha_{kj}} = B_{pq} B_{kj} (c_{pj} - c_{pk} + c_{qk} - c_{qj}) \quad (13)$$

From Eqs. (12) and (13), it is seen that these factors only depend on the network configuration and not on the bus power injections.

The power flows in the system with varying PST angle α_{kj} in terms of PSDFs are:

$$P_{kj} = P_{kj,0} + \alpha_{kj} v_{kj}^{kj} \quad (14)$$

$$P_{pq} = P_{pq,0} + \alpha_{kj} v_{kj}^{pq} \quad (15)$$

where $P_{kj,0}$ and $P_{pq,0}$ are the reference flows, i.e., the DC flow without considering any PSTs.

In presence of multiple PSTs in the system, the equations for the line power flows are adapted accordingly. If another PST is present in the line mn too, Eqs. (14) and (15) are modified as:

$$P_{kj} = P_{kj,0} + \alpha_{kj} V_{kj}^{kj} + \sum_{\substack{(m,n) \\ (m,n) \neq (k,j)}} \alpha_{mn} V_{mn}^{kj} \quad (16)$$

$$P_{pq} = P_{pq,0} + \sum_{(m,n)} \alpha_{mn} V_{mn}^{pq} \quad (17)$$

Hence, every PST contributes with an extra term to the power flow in the line.

It can be concluded that under the DC load flow assumptions, the active power flow in a line is a linear combination of the PST settings. The key element is the network configuration. Therefore, if the matrix of PSDFs is written as \mathcal{E} , a particular choice of PST angles leads to a constant term $\Delta \mathbf{P} = \mathcal{E} \alpha$ added to the line flows at zero phase shift.

5.2. Modeling of HVDC in power flows

The quadratic power flow equations are linearized for the DC grid [31]. The steady-state power flow in a HVDC line from bus k to m is represented by Eq. (18), where V_k is the voltage at bus k :

$$P_{km} = \frac{V_k(V_k - V_m)}{R_{km}} \quad (18)$$

R_{km} is the resistance of the HVDC line between the two buses. If it is assumed that the DC voltages are rather close to the nominal voltage, Eq. (18) can be approximated as:

$$P_{km} \approx \frac{V'_k - V'_m}{R_{km}} \quad (19)$$

The resulting voltages V'_k and V'_m give only the deviation from the nominal voltage at the reference bus. The ohmic losses in the DC grid are neglected.

6. Advantages of coordinated control of PFC operation

In order to address the challenges involved in achieving the environmental targets of the European Commission an FP7 project called Twenties was initiated in the year 2010 by the Commission. Work package 5 of the project addressed network enhanced flexibility (NET-

FLEX), which addresses how the existing transmission grid of Europe can be utilized with the help of PFCs and manage more renewables in the system.

6.1. Achieved flexibility in terms of daily system operation

The PFCs, especially the PSTs that are already installed in the power system of Europe, and especially in Western Europe, are used when the loop flows are over and above their pre-specified values by the TSOs. These devices are also often used to manage system security by the TSO for its own control area or to manage problems originating in other control areas through coordination process. Within the scope of this work package, algorithms were developed to demonstrate that increased coordination among TSOs can resolve complex security problems which otherwise required costly measures.

Eight PSTs in CWE that were considered to show the coordination effect were Zandvliet, Van Eyck (two of them), Diele (two of them), Meeden (two of them), and Gronau. They are shown in **Figure 3**.

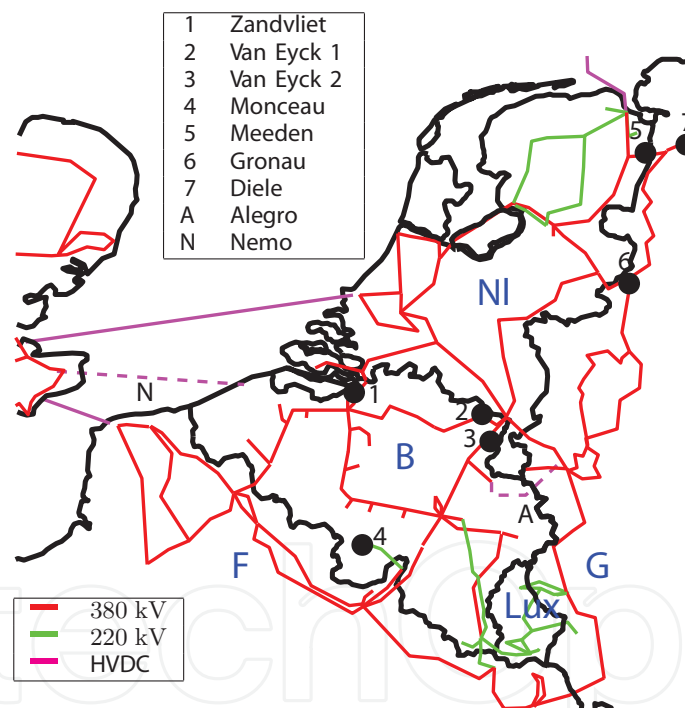
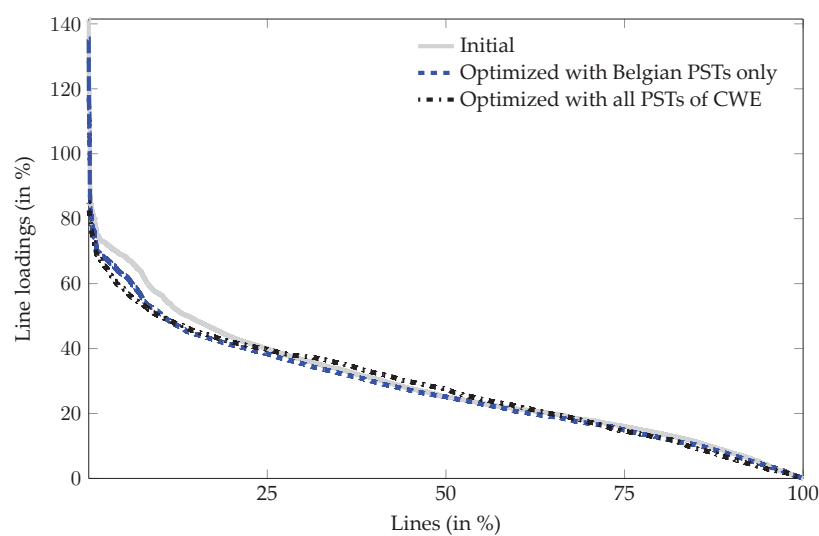


Figure 3. Existing controllable devices installed in CWE area [32].

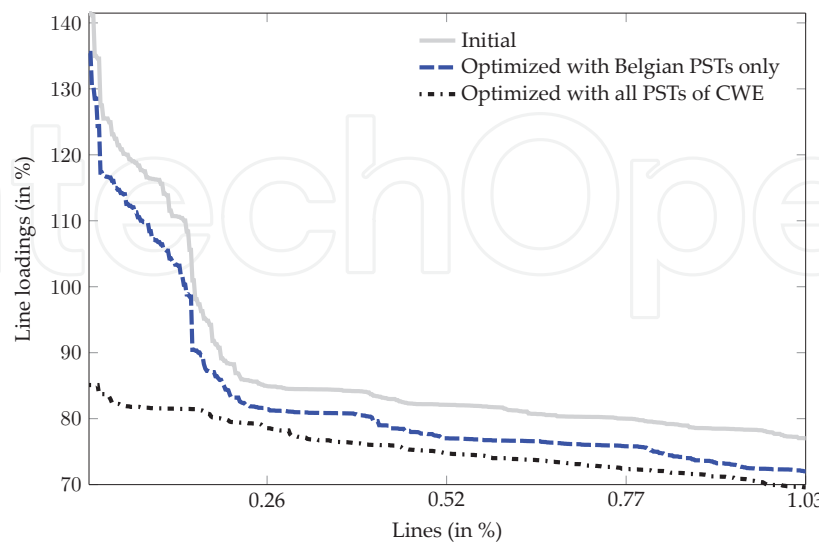
Figure 4 shows a margin analysis graph. In the graphs, the loadings of the lines present in the critical branches (CB¹⁰) list are sorted from highest to lowest both for “N” and “N–1” situations and for all 24 hours, before and after optimization. The initial and optimized loadings present in the graphs can be defined as the ratios of initial to the maximum flows and ratios of the optimized to the maximum flows, respectively, for each line and for each contingency. On the

¹⁰ It is defined as a transmission line that has a potential risk of being constrained due to network security reasons.

x -axis, the individual line loadings for all considered lines in every contingency situation are shown in a monotone diagram. A total of 45 CBs are taken into account in basecase, which considers all CBs in operation. Each CB is then taken out one at a time, and the flows on the remaining 44 CBs are calculated. Hence, each line occurs 45 times in each file and 24 files are generated for a day. The figure shows the results for all 24 hours and the number of data points along the horizontal axis is 48,600 [(45 CBs for basecase + 45 “N-1” cases \times 44 CBs) \times 24]. The x -axis shows lines (CBs) as a percentage, with each 25% representing 12,150 data points in **Figure 4(a)**. **Figure 4(b)** shows the zoomed-in part of the graph that is most relevant, consisting of first 500 data points. Hence, $\frac{500}{48,600} \times 100$ is the whole segment.



(a) Normal view



(b) Zoomed view

Figure 4. System loading.

It is evident from the figure that the system is already 41% loaded over the maximum allowable (represented by the solid line). This scenario is characterized with high wind in Northern Germany, creating congestion in the Belgian controlled area for a day in the past before the initiation of this project. The TSO of Belgium was not able to solve the problem with any noncostly means available and had to resolve the problem with costly measures (internal redispatch of generators). The problem still remains unsolved¹¹ with the help of Belgian PSTs only (Zandvliet and Van-Eyck's), as is evident from the dashed line in the figure. However, when all the considered PSTs are optimized simultaneously the overloading was eliminated and a margin of approximately 15% from the maximum allowable loading is achieved. This extra margin can be used to deal with uncertainties in the system, e.g., renewables. In Europe, this type of situation is increasing and will be going to increase in the future due to rapid integration of more renewables into the existing system. The coordination among TSOs is an essential noncostly means that TSOs must account for on a day-to-day basis in order to make the existing grid operation more flexible in terms of PFC operation so that both increased penetration of renewables and uncertainties inherent to them can be handled.

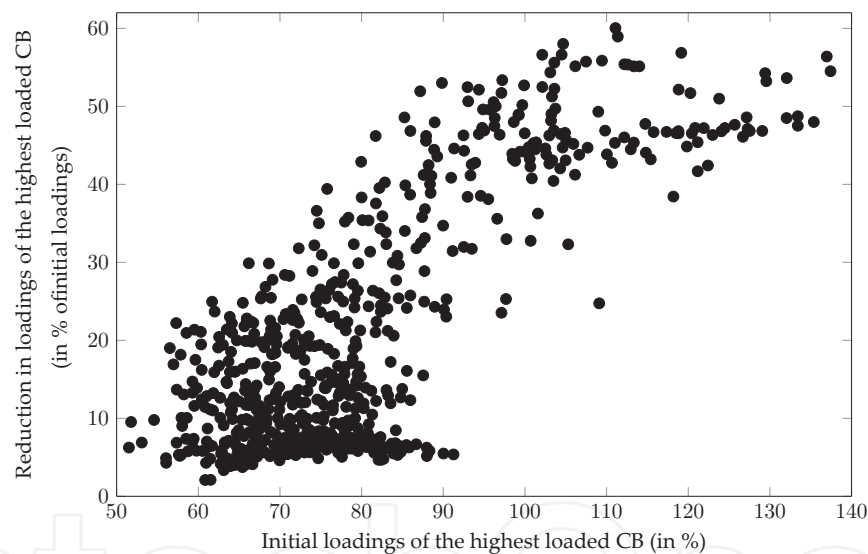


Figure 5. Reduction of highest loaded CB for every time-stamp for January 2013.

The developed algorithm was also validated for an entire month of January 2013 (it was a high wind period), the results of which are shown in **Figure 5**. The x -axis shows the initial loading of the system for each hour of the day of the entire month, whereas the y -axis represents the reduction in system loading from the initial. It is evident that in many cases the system was overloaded (all points on the x -axis beyond the 100% mark are overloaded situations). A careful investigation of the figure reveals that a significant reduction of overloading is achieved for the cases that are highly overloaded. For example, approximately 55% of loading is reduced for the case, which is initially loaded for 138%. In this particular

¹¹ Although the overloading is reduced a bit.

case additional 17% ($100\% - [138 - 55]\%$) of margin is achieved. Moreover, for all of the cases the system is relieved from overloading, and a significant amount of extra margin is attained for each of them. This clearly indicates coordination among TSOs indeed helps to avoid costly measures of removing system congestion, and will be often required in the future in Europe [33].

6.2. Achieved flexibility in terms of increased wind penetration

Increased intermittency demands increased balancing actions in a power grid. Severe congestion are frequent, demanding an expansion of the transmission grid. However, transmission grid expansion in Europe is severely limited. Hence, the existing grid must handle the increased penetration of uncertain generation sources. This can only be achieved by a flexible grid operation through inter-TSO coordination. The same work package addressed how much additional wind can be handled in the existing transmission grid in Europe.

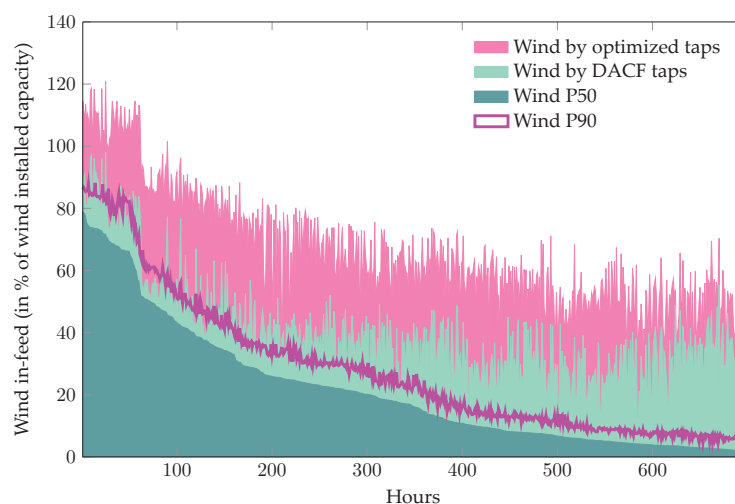


Figure 6. Additional wind that could be integrated during January 2013.

Figure 6 shows the results of 1 month validation of additional in-feed of wind. The forecasted wind or P50¹² values are represented by the cadet blue area for the entire month. The DACF files already integrate certain values of PST tap settings in order to keep loop flows through the transmission system of a TSO within certain limits decided by the TSOs themselves. The additional stress due to those already included tap positions is represented by the aquamarine area over and above the P50 values that can be handled with the help of all the PSTs in CWE, and for a given direction of stress (that is, for a certain GSK).¹³ The wind P50 values are already integrated in the DACF files. The additional stress that can be han-

¹² Pxx represents an "xx" amount of probability that the wind in real time remains below the corresponding value (considering normal distribution).

¹³ GSK, termed as generation shift keys defines the way of change in net position that is mapped to the generating units in a bidding area, representing in average the relation between the change in output of every generating unit inside the same market area. More information can be found in Ref. [33].

dled by optimizing all the PSTs in CWE area is represented by the carnation pink area. The fuchsia line represents the wind P90 values. The figure clearly shows that a significant amount of additional wind in-feed is possible in CWE with the help of PST coordination, which can even surpass P90 values in many cases. Hence, it is clear that an increased TSO coordination can help to handle more intermittency in the existing transmission grid by making the latter more flexible in operation [33].

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