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***Abstract*—Along with the increased installation of the distributed energy resources (DER) in distribution system, long-term voltage stability at the transmission level can be improved if proper coordination is developed between DERs and the existing grid controllers, e.g., load tap changer (LTC). This paper analyzes the problem of long-term voltage instability and presenting possible countermeasures. The study summarizes essential aspects for modelling, including LTC, DERs, and especially voltage dependent load. A coordination between DERs and LTC is proposed to allocate better power supply, especially at the coupling points between transmission and distribution networks, i.e. primary substation. A case study is performed using a modified CIGRE medium-voltage benchmark network. The simulation results have shown that the coordination has substantially improved the long-term voltage stability in the way of using the reactive power support from DERs and increasing the LTC position instated of decreasing as the traditional method.**

***Index Terms*—Distribution energy resource, control coordination, long-term voltage stability.**

I. Introduction

Due to a lack of power supply to the (passive) distribution network after emergencies, an issue of long-term voltage instability might occur [1]. One the one hand, the presence of distributed energy resources (DER), e.g. solar PV, wind, or storage, can be considered to resolve this issue. On the other hand, the coordination of DERs with the existing grid controller, i.e. load tap changer (LTC) is essential to secure the operation between transmission and distribution networks. This has been highlighted also by ENTSO, ISGAN, NERC [2]–[4].

As defined in [5], voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being violated from a given operating condition by disturbances. The time frame for voltage stability may vary from few seconds (short-term) to tens of minutes (long-term). This paper deals with long-term voltage stability in the transmission system, especially at the coupling points between transmission and distribution networks. Investigating long-term voltage stability requires proper models to capture accurately grid dynamics. In [1], conventional components such as LTC and dynamic load have been included. Especially, voltage dependent load, i.e. induction motor, plays a crucial role in causing the instability. To analyze the impact of DERs on long-term voltage stability, various models are presented in [6]–[9]. A simplified version of the Western Electricity Coordinating Council (WECC) model is used in [6], which omitted fast reactive current injection characteristic during the fault as well as the plant-level controller of inverter-based generator model. A model for large-scale DER generation is presented in [7]. An improved PQ controller at the plant level is proposed to effectively support the long-term voltage stability. Furthermore, in [8], [9], the impact of tripping of DER due to the terminal voltage drop and the interaction among multiple DERs is considered by using a detailed DER model.

The availability of DERs in distribution networks can contribute to support long-term voltage stability. In [10], a distributed model predictive control (MPC) is developed to keep the voltage of multi-area within the acceptable bounds. Authors in [11] presented a centralized MPC to regulate the voltage at coupling points of DERs. In [12], authors investigated the challenges of DERs integration into low voltage (LV) networks. The risks of voltage rise related to the disconnection of DERs were identified, and active power curtailment approaches were proposed to mitigate the problem of voltage rise. Further, adaptive coordination of sequential droop for PV is developed in [13] to solve the voltage rise problem while being able to reduce the amount of power curtailment. In [9], an adaptive proportional-integral controller is developed for multiple inverters to regulate DERs's terminal voltages. It showed that the voltage correction of the one or several DERs may result in over-voltage at another DER's terminal bus, leading to a need for system-wide coordination. The coordination between DERs and LTC has been investigated in [6], [10], [11], [14] to address instability issue at the primary side of the high-voltage/medium-voltage (HV/MV)

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transformer. However, the coordination, especially between DERs and LTC, during stressed operation conditions (e.g., after a large disturbance) is still a challenge.

This paper aims to investigate the capability of DERs to support long-term voltage stability. First, we reformulate the stability problem, considering essential elements such as LTC, and voltage dependent load. Second, we investigate a possible coordination scheme to ensure the support of DERs and LTC in emergencies. Lastly, a simulation is performed in a modified CIGRE MV benchmark network to show the benefit of adequately coordinating between the grid operator and DERs.

II. Components Affecting Long-term Voltage Instability

In this section, the long-term voltage instability is discussed. First, different elements affecting long-term voltage instability such as LTC and dynamic load are presented. Then, a simulation is performed using MATLAB/Simulink to illustrate the issue of voltage instability at the coupling point between transmission and distribution (T-D) networks.

A. Load Tap Changer

The HV/MV transformer is considered as an interface between the T-D network. Normally, it is installed with the LTC which operates automatically to maintain voltage of the secondary side of the transformer within a predefined limit. While a disturbance occurs that cause a voltage drop, the LTC adjusts transformer's tap-setting to bring back the secondary voltage to its pre-disturbance level. The operation of taps can be summarized as follows [6]:

$$tap_{k+1} = \begin{cases} tap_k + \triangle tap\,, \text{ if } V > V_0 + d \text{ and } tap_k < tap^{max} \\ tap_k - \triangle tap\,, \text{ if } V < V_0 - d \text{ and } tap_k > tap^{min} \\ tap_k\,, \text{ otherwise} \end{cases} \tag{1}$$

where: tap_k and tap_{k+1} are the current and next tap position; $\triangle tap$ is the size of each tap step; and the tap^{min}, tap^{max} are the minimum and maximum tap limit, respectively.

The tap is activated depending on the measured voltage V. The tap position tap_{k+1} will be increased or decreased if V is out of a deadband $V_0 \pm d$, where V_0 is the voltage reference and d is the deadband limit. Furthermore, tap movement needs a fixed delay time (normally, from 5-8 seconds) to reach a new position due to mechanical requirements.

B. Dynamic Load Model

Long-term voltage stability involves slow-acting equipment devices such as generator current limiters, LTC, and controlled loads. The attempt to restore power consumption of the dynamic load is usually the reason for long-term voltage instability [15], [16]. So, that is important to consider the load model in long-term voltage study. In this work, the exponential load model is expressed as follows:

$$P = P_0 \left(\frac{V}{V_0}\right)^{\alpha}, \tag{2}$$

TABLE I
The α and β value for different load components

Load component	α	β
Incandescent lamps	1.45	-
Room air conditioner	0.5	2.5
Furnace fan	0.08	1.6
Battery charger	2.59	4.06
Electronic compact fluorescent	0.95-1.03	0.31-0.46
Conventional fluorescent	2.07	3.21

$$Q = Q_0 \left(\frac{V}{V_0}\right)^{\beta} \tag{3}$$

where: V_0, P_0, and Q_0 are the rated terminal voltage, active power, and reactive power, respectively. α and β are the exponents controlling the nature of the load.

Table I shows different load devices, which has been modelled as the exponential load model with different α and β values [1]. However, the values α and β are normally set to 1 and 2 for constant current and constant impedance, respectively.

C. Over Excitation Limiter

Over excitation limiters (OEL) are also named as maximum excitation limiters or field current limiters. It was designed to protect the field winding circuit under stress conditions (i.e., under the large disturbance) [1]. The operation of OEL can be explained briefly as follows. When a fault happens nearby, the generator terminal voltage is dropped below the normal operation. The excitation system will react to support the voltage by increasing the field current, causing the field winding is overloaded. The OEL, then, will reduce this high current to a normal setting after a predefined time interval due to the thermal limit. As can be seen in Fig. 1, there are two types of delay interval for the OEL, namely fixed delay time (Fig. 1 (a)), and inverse delay time (Fig. 1 (b)). When the field current exceeds the limited value for a fixed delay time, the field current will be reduced to the limit value after the corresponding delay time (normally in the range of 10-20 seconds). In the case of using the inverse delay time setting, the higher field current level is allowed for a shorter time,

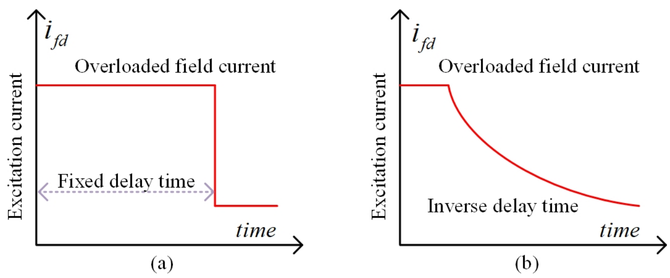

Fig. 1. Time delay characteristic of over excitation limiter.

and the lower field current level is allowed for a longer time. The operation of OEL is to protect the generator winding. However, due to the limited field current, the reactive power support from the generator is reduced, which could affect long-term voltage stability.

D. Distributed Energy Resources

In this paper, DERs are modelled as voltage sourced converter connected with an LCL filter. The DC side is assumed as a constant DC voltage. The DER is interfaced with the grid through a transformer. In this work, the DERs are operated in grid following mode [17], which includes a single current control loop to follow the P^*, Q^* control signals from the higher control layer. The current reference signals are determined in the dq frame, as follow:

$$\begin{bmatrix} I_d^* \\ I_q^* \end{bmatrix} = \frac{3}{2} \begin{bmatrix} \frac{P^*}{V_d} \\ \frac{Q^*}{V_d} \end{bmatrix} \tag{4}$$

where: V_d, V_q, and I_d, I_q are the inverter voltages, current in dq frame, respectively.

The PI controller is designed to minimize the error between input current references (obtained from equation (4)) and measured inverter currents. Finally, the output of PI controller is used as modulation signals for the PWM to generate the inverter gating signals.

III. Instability Formulation

In this section, a test case is presented using a modified CIGRE medium voltage benchmark network, as described [18], [19]. The single-line schematic diagram of the test network is shown in Fig. 2. The grid is a three-phase system with 20 kV nominal phase to phase voltage, and the system frequency is 50 Hz. There are two parallel transmission lines that have been added to connect the external grid and the HV-MV substations. The external network is represented by a 110 kV/50 Hz three-phase voltage source, with a short-circuit power of 500 MVA and R/X ratio of 0.1. The transformer with a LTC controller is installed between Bus 0 and Bus 1, which is designed to keep the voltage at Bus 1 within a range from 0.985 p.u. to 1.015 p.u. A synchronous generator is installed at the HV-MV substation. The MV network is fed by the two 25 MVA transformers associated with LTC. There is a mix of residential (L_{iR}) and industrial load (L_{iC}) in the network (with i is the bus number, where load is connected). The residential loads are modelled as the power constant loads with $\alpha = \beta = 0$. The voltage dependent model are used to present the industrial load. The details of line parameters of this benchmark network are provided in Appendix (Table III).

Consider a three-phase fault occurs at one of the two parallel transmission lines between external bus and Bus 0, as depicted in Fig. 2. This transmission line trips at time $t = 0$ to isolate the fault. After a short-term period with dynamics assumed to be stable, the system enters a long-term stage where voltage stability is of concern. A simulation for this study of long-term voltage stability involves slow-acting equipment (e.g., LTC, OEL). In this simulation, the voltage measurement at HV bus

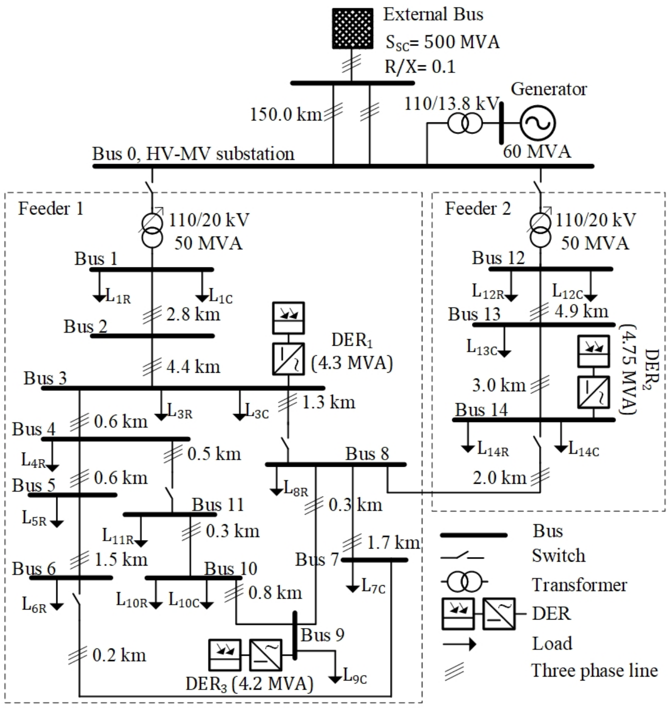

Fig. 2. Modified CIGRE MV distribution network benchmark.

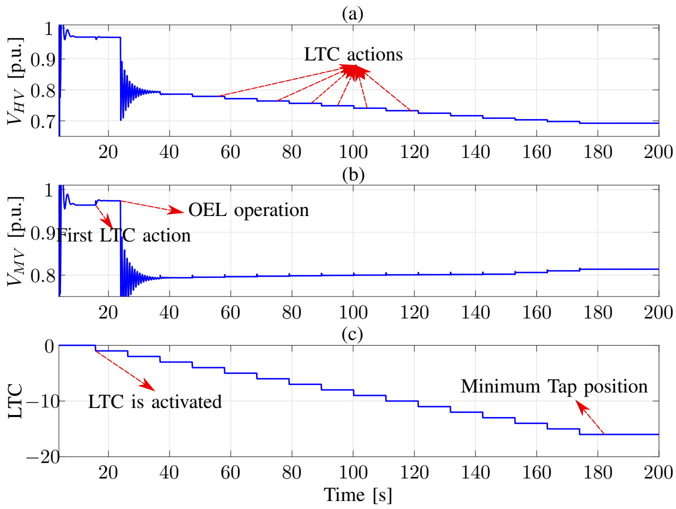

Fig. 3. Long-term voltage instability. V_{HV} and V_{MV} are the voltage magnitude measured at Bus 1 and Bus 2, respectively. LTC is tap position of the HV/MV transformer between Bus 1 and Bus 2.

(i.e., Bus 0) and at MV bus (i.e., Bus 1) are shown in Fig. 3. After a short-term dynamic period, the voltages at HV and MV buses are stable at $V_{HV} = 0.973$ p.u., and $V_{MV} = 0.928$ p.u., respectively. Thus, the LTC controller is activated to increase the voltage at Bus 1. The increasing of the voltage at Bus 1, following the tap movement is shown in the Fig. 3. The first LTC action is activated after 15 seconds.

In the sequence of long-term voltage stability, it is important to take into account the operation of OEL. The field current of

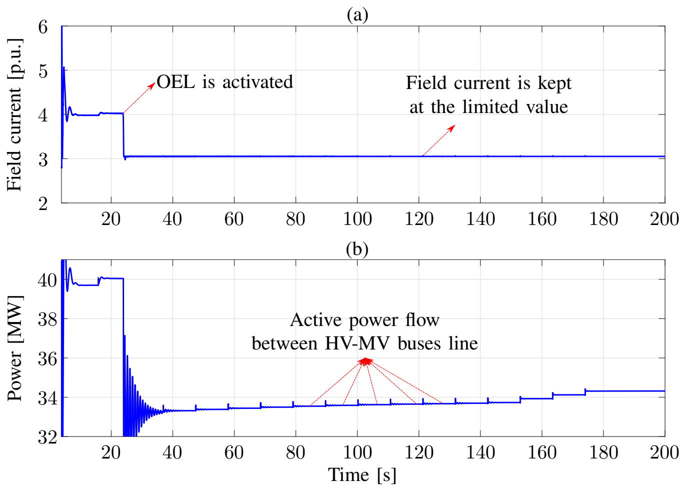

Fig. 4. (a) - Field current of the synchronous generator. (b) - Power flow between HV-MV buses in feeder 1.

TABLE II
SIMULATION CASE WITH DIFFERENT α AND β VALUES

Simulation case	α	β
Case 1	1	1
Case 2	1	1.5
Case 3	1.5	1.5
Case 4	1.5	2
Case 5	1.5	2.5
Case 6	2	2
Case 7	2.5	2.5

synchronous generator is allowed to be overloaded (i.e., $i_{fd} > 3.0618$ p.u.) for a fixed 20 seconds, as shown in Fig. 4-(a). Thus, the OEL is activated at $t = 24s$ to protect the generator winding circuit. As the result, the voltages at HV and MV buses are dropped to $V_{HV} = 0.815$ p.u., and $V_{MV} = 0.824$ p.u., respectively.

It is worth to mention that the MV grid consists of a mix of residential and industrial load (i.e., dynamic load). In Section II-B, the model of dynamic load was discussed. The active and reactive power consumption of a dynamic load depends on its terminal voltage. Thus, higher voltage at the MV side of the primary substation causes the increase of the total load consumption in the MV network. The active power flowing through the HV-MV buses in the feeder 1 is presented in Fig. 4-(b). The active power supplying to the distribution grid increases along with the LTC actions. However, the limited power transfer capability is reached due to the tripping of transmission lines. Consequently, the voltage at the HV side of the transformer (i.e., Bus 0) is decreased below the acceptable operating range. This may activate the low voltage protection system, which could lead to cascading tripping of transmission lines and a possible voltage collapse.

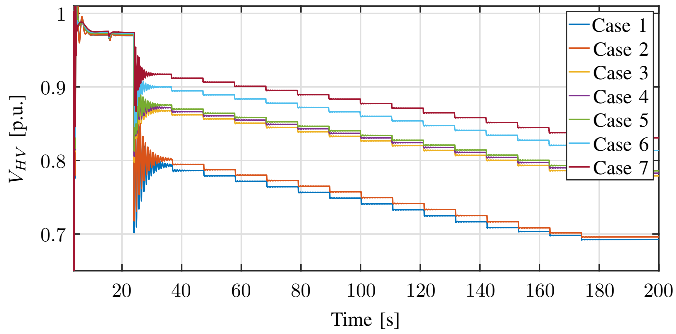

Fig. 5. Voltage profiles at the Bus 0 (HV bus) with different load characteristic.

To analyze the impact of load modelling into the long-term voltage stability, different simulation cases in Table II were performed. As discussed in Section II-B, different load components will have different set of α and β values. Thus, the Table II presents aggregated load model. The voltage profile at transmission network, V_{HV} is shown in Fig. 5. It can be observed that the simulation case 1 with $\alpha = 1$ and $\beta = 1$ is the worst case with lowest V_{HV} profile after the fault. Thus, having the proper is important aspect for long-term voltage stability study.

IV. COORDINATION SCHEME FOR DERS AND LTC

As aforementioned, the coordination between DERs and LTC can contribute to improve the voltage instability issue at the primary side of the HV/MV transformer. The coordination strategy needs to consider DER's local control objectives to avoid possible conflicts. In addition, the nonlinear dynamic of DERs needs to be taken into account when their capability in voltage control is explored [9], [12], [13]. In [9], an adaptive proportional-integral controller is developed for multiple DERs to regulate DERs's terminal voltages. It shows that the voltage correction of other DERs may result in over-voltage at another DER's terminal bus, leading to a need for system-wide coordination.

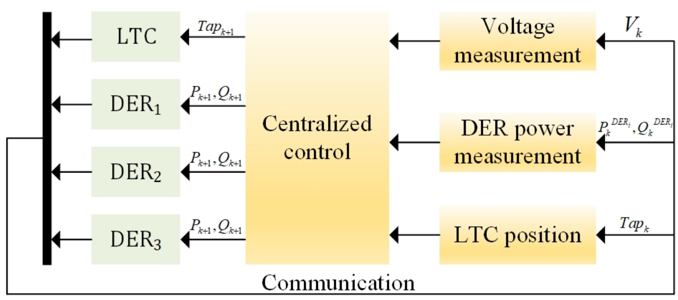

Fig. 6. A centralized coordination control. $P_k^{DER_i}$, $Q_k^{DER_i}$, and Tap_k are the active, reactive power measurement of DER_i, and LTC position at time step k, respectively. Furthermore, $P_{k+1}^{DER_i}$, $Q_{k+1}^{DER_i}$, and Tap_{k+1} are the control signal of active, reactive power of DER_i, and LTC position will be used at time step $k+1$, respectively.

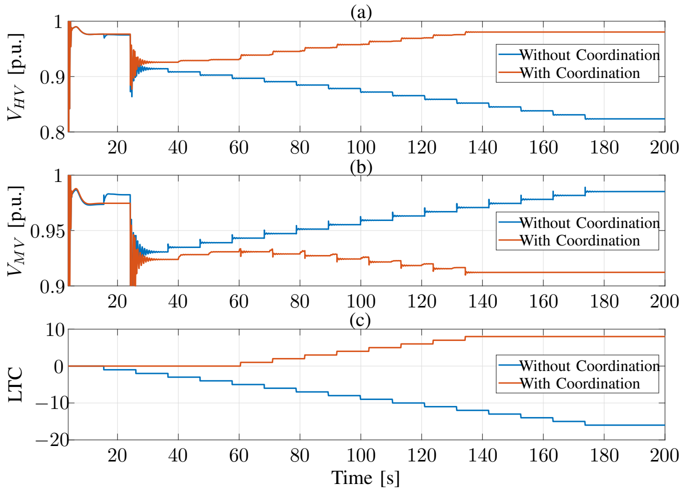

Fig. 7. Voltage profiles in case of with and without the coordination. V_{HV} and V_{MV} are the voltage magnitude measured at Bus 0 and Bus 1, respectively. LTC is tap position of the HV/MV transformer between Bus 0 and Bus 1.

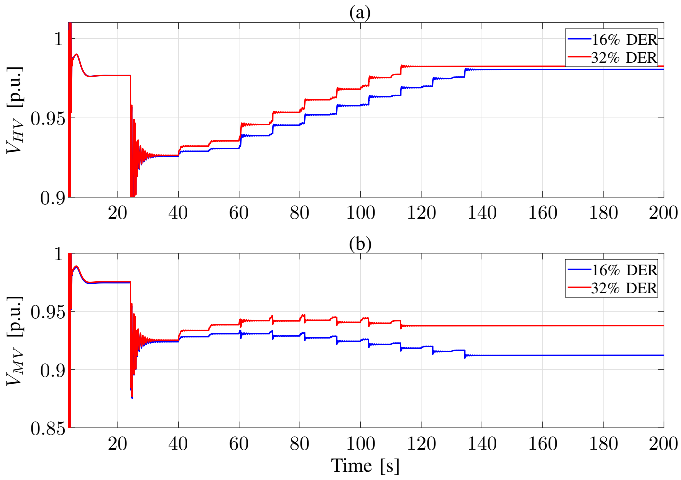

Fig. 8. Voltage profiles in case of with and without the coordination of V_{HV} and V_{MV} with different DER penetration levels.

In this study, it is assumed that a coordination scheme can overwrite DER's local controllers with its control signals from the coordination scheme. The centralized coordination control is presented in Fig. 6, which aims to coordinate the operation of LTC and available DER resources to avoid long-term voltage instability after fault. The active, reactive power output (i.e., $P_k^{DER_i}$, $Q_k^{DER_i}$) of DER and current position of LTC (i.e., Tap_k) are collected at the centralized control. Then, the new control signals for LTC and DERs are processed depending on the voltage level and available DERs power. In this section, the modified CIGRE benchmark network in Section III is used again to show the benefit of having coordination between LTC and DERs. There are three DER units which are added at Buses 3, 14, and 9 with their rating power of S_1 = 4.3 MVA, S_2 = 4.75 MVA, and S_3 = 4.2 MVA, respectively [20]. In this case, the DER can support 16% total power consumption of loads.

In this simulation, the proposed strategy is implemented in the Simulink model to coordinate DERs and LTC. The necessary information (i.e., voltage magnitude, DER's power) can be collected via measurement or estimated using state estimation [21]. In this work, that information is collected via the communication system. Then, the long-term voltage stability is analysed in the case of with and without coordination. Fig. 7 presents the time sequence of control actions. The recorded primary voltage at the pre-fault stage is $V_{HV}^0 = 0.996$ p.u. The coordination scheme is activated based on the alarm signal with the objective is to bring the primary voltage back to the pre-fault value. The simulation results show that, the proposed coordination smoothly brings the primary voltage back to the pre-fault value while keeping the secondary voltage in its limits [0.9 1.1] p.u. As can be seen from Fig. 7, in the range of time $t = 20s$ to $t = 60s$ the voltage is slightly increased while the LTC is kept unchanged. This is an advantage of coordinated control. In this period, the power from DERs is still available. Thus, the controller keeps the LTC unchanged and used only power from DERs to support the voltage. In the next period from $t = 60s$ to $t = 140s$, the powers from DERs reach their limits. Thus, the controller must use the support from LTC operation with a higher *cost* (i.e., operation and maintenance cost of LTC). The LTC increases its position to increase the primary voltage of the transformer. Due to the increasing LTC position, the secondary voltage is decreased. However, the secondary voltage of the transformer is kept at the limit of [0.9 1.1] p.u.

To show how the DER can support the long-term voltage stability, there more DERs are added to the network (S_4 = 4.3 MVA at Bus 3, S_5 = 4.75 MVA at Bus 14, and S_6 = 4.2 MVA at Bus 9). So, the DER penetration level is increased up to 32%. The Fig. 8 shown the voltage profiles of V_{HV} and V_{MV} in case of different DER penetration levels. It clearly shows the benefit of having more DERs into the network. The V_{MV} voltage is controlled to be stable faster with higher penetration of DER. It is important to note that, the coordination can improve the voltage at HV bus while keeping the voltage at MV bus in the limit of 0.9 p.u. So, this is the trade-off between the HV-MV buses. This simulation results show the proposed control method can support the long-term voltage stability after the large disturbance.

V. Conclusion

The long-term voltage stability at the T-D interface is discussed in this paper. Essential aspects for modelling, including load tap changer (LTC), distributed energy resources (DER), and especially voltage dependent load is summarized in this study. Coordination between DERs and LTC is proposed to allocate better power supply at the coupling points between transmission and distribution networks, i.e. primary substation. The study is performed using a modified CIGRE medium-voltage benchmark network. The numerical results show a better voltage profile with the coordination scheme after the large disturbance. The centralized control collected the LTC status as well as the active, reactive power output of DERs.

In case of emergency conditions, the reactive power from the DERs is used to support the voltage. The LTC is used in the later phase (due to the high operation cost) when DERs reach their capacity limit. Instated of decreasing the tap position as which was designed for LTC, the centralized control increased the tap position to support the HV voltage while keeping the medium voltage in the operation range.

The case study shows the advantage of having coordination between grid operators and DERs. Thus, we expect that different coordination controls will be developed to support the long-term voltage stability taking into account other aspects such as dynamic behaviour or uncertainty from DERs. Furthermore, long-term voltage control using advanced controllers (e.g., model predictive control, reinforcement learning), which optimally control the voltage could bring other advantages for system operators.

APPENDIX

The line data of the CIGRE MV distribution network is given in Table III. It is worth to mention that, the unit of resistance, reactance, and susceptance are given in ohm/km, ohm/km, and uS/km, and the line length is shown in Fig. 2.

TABLE III
LINE DATA OF CIGRE MV DISTRIBUTION NETWORK

From	To	R	X	B	R0	X0	B0
1	2	0.50	0.72	47.49	0.82	1.60	47.49
2	3	0.50	0.72	47.49	0.82	1.60	47.49
3	4	0.50	0.72	47.49	0.82	1.60	47.49
4	5	0.50	0.72	47.49	0.82	1.60	47.49
5	6	0.50	0.72	47.49	0.82	1.60	47.49
6	7	0.50	0.72	47.49	0.82	1.60	47.49
7	8	0.50	0.72	47.49	0.82	1.60	47.49
8	9	0.50	0.72	47.49	0.82	1.60	47.49
9	10	0.50	0.72	47.49	0.82	1.60	47.49
10	11	0.50	0.72	47.49	0.82	1.60	47.49
11	4	0.50	0.72	47.49	0.82	1.60	47.49
3	8	0.50	0.72	47.49	0.82	1.60	47.49
12	13	0.51	0.37	3.17	0.66	1.61	1.28
13	14	0.51	0.37	3.17	0.66	1.61	1.28
14	8	0.51	0.37	3.17	0.66	1.61	1.28

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