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# Distribution system congestion management through local flexibility market

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**Abstract:** Congestion that is the increasing problem of many distribution systems can be resolved using the local flexibility market (LFM) as a market-based solution along with non-market-based solutions such as reactive power control, network reinforcement, coordinated voltage control etc. The objective of this study is to show how the market and non-market-based solutions can relieve congestion by designing and using a simulation environment. The idea of the study is to solve the congestion in distribution networks through LFM, non-market-based solutions, or a mix of those alternatives. To do so, the simulation environment enables us to analyse and understand the features of three scenarios associated with congestion management (CM). A deterministic optimisation algorithm in the distribution management system is used to select the best solution candidate for CM.

## 1 Introduction

One of the essential changes in the electricity industry compared to recent decades is the emergence of the distributed generations (DGs), mainly connected to the distribution systems [1]. DGs that partially substitute the centralised power plants put more stress on the distribution systems. Irrespective of the positive aspects of the mentioned change, such as carbon emission reduction, congestion is the problem that is occurring in distribution systems because distribution systems have been traditionally designed to feed customers not to host generators. Due to environmental concerns, the DGs' penetration, especially renewable kinds, has experienced a sharp rise intensifying the congestion problem. On the consumption side, the recent changes such as transportation electrification have not been in favour of congestion elimination but escalating it.

Congestion management (CM) techniques fall into two categories, including non-market- and market-based solutions [2]. Non-market-based solutions mostly embrace actions that do not require coordination between parties other than the grid operator itself. Therefore, self-governance is the feature of non-market-based solutions appreciated from the distribution system operator's (DSO's) point of view. Network reinforcement, coordinated voltage control (CVC), reactive power control, network reconfiguration, are some examples of non-market-based solutions. On the contrary, market-based alternatives are established according to coordination and cooperation between DSOs, transmission system operator, flexibility service providers (FSP) etc. A flexibility market is needed to make the market-based solutions work where the flexibility of generation/consumption can relieve congestion.

In the position of a DSO dealing with congestion, a solution must satisfy a degree of reliability, viability and cost-effectivity. Since the non-market-based alternatives are not new practices for grid operators anymore as well as self-governance feature of them, the mentioned factors can be met in a easier way by adopting non-market-based solutions compared to new alternatives such as market-based solutions. Therefore local flexibility market (LFM) as a market-based solution should be reliable, viable, and cost-effective enough to be able to complete with the non-market-based CM solutions.

The authors of the paper believe that neither non-market-based solutions nor flexibility markets alone can efficiently manage congestion, but a combined solution depending on the congestion situation brings the most benefit for DSOs and society in general. The scenarios of this paper demonstrate how market- and non-market-based solutions are deployed for CM.

## 2 Methodology

### *2.1 CM based on LFM*

The day-ahead (DA) forecast of the network's state is required for the short-term planning of grid operation. The horizon of the DA forecast could be from hours to a DA. Having said that, according to Fig. 1, once the DA market auction is cleared at noon, DSOs can forecast their network's state for the coming hours based on the position of the energy market traders in DA market and also historical data of consumption patterns, weather condition etc. In the case of predicted congestion, various solutions in the category of market or non-market-based solutions might be used for CM. Market-based alternatives in the form of flexibility bids are collected from FSPs after providing them with the flexibility needs of DSOs by LFM's market operator. Based on the proposed market timeframe shown in Fig. 1, the LFM market is open for one hour from 15 to 16. Once the LFM is closed, the merit order list (MOL) of flexibility bids and the location of bids/resources are then sent to the flexibility buyer (DSO). Flexibility bids as market-based solutions along with non-market-based solutions (e.g. reactive power control, CVC etc.) create a group of solution candidates. The predictive optimal power flow (OPF) is one of the application systems in the distribution management system (DMS) that designates the best solution from solution candidates for CM. If the final solution is market-based kind, then the relevant FSPs are informed about that at 18. It should be emphasised that the decision-making process of the predictive OPF should be transparent to have a level-playing field for all LFM traders and maximise the trust between stakeholders. In real-time, according to the network's state, the OPF decides the best optimum control action for the network's operation. The decision can be the

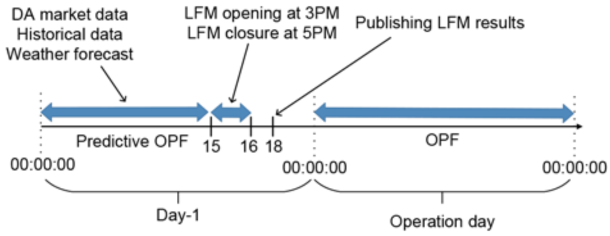


**Fig. 1** *Proposed timeframe of the LFM*

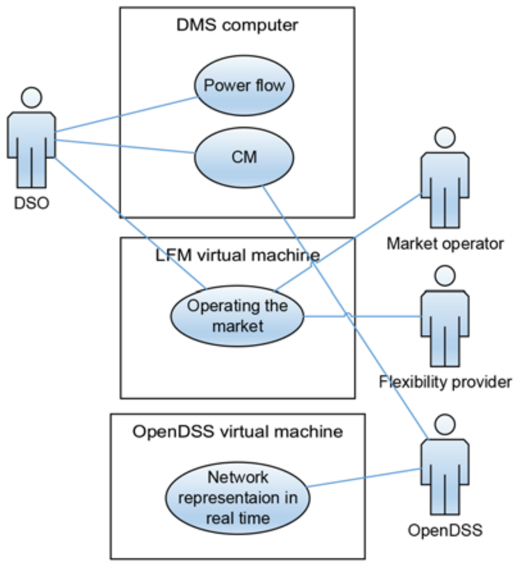


**Fig. 2** *High-level use case of the simulation environment*

activation of the previously bought flexibility from LFM, non-market-based alternatives' activation (e.g. reactive power control) or a combination of them. In the next two paragraphs, the architecture of the simulation environment and its system use cases will be clarified.

### 2.2 Simulation environment

The simulation environment in Fig. 2 consists of three virtual machines (VMs), which represent the DMS, LFM and distribution system. The DMS VM characterises the DSO's control centre in charge of monitoring and CM of the distribution system. The LFM represents the functionalities related to the LFM including opening the auction on a DSO's request, publishing the characteristics of the flexibility need for FSPs, creating a MOL for the DSO's use and market clearance. The OpenDSS VM represents the distribution system that informs the DMS with regard to the network's state (e.g. voltage, current) in real-time operation.

The idea of VMs is to create a simulation environment that resembles close enough to the reality of distribution systems where issues associated with interoperability, imperfect information of the complete situation in decision making, coordination mechanisms between market stakeholders etc need to be taken into account. When VMs exchange information with each other, and each stakeholder makes independent decisions, the raised issues are considered which is why the environment consists of several VMs have been designed. It should be noted that the simulation environment lacks the OPF simulation, and therefore results concerning the real-time operation will not be provided in the paper.

## 3 Results

Three scenarios are compared to illustrate the impact of various alternatives for CM. The operation of the network without using any controllability is shown through scenario 1 as a reference in order to understand what is the situation of the network if no controllability is available for the DSO. Then the target is to increase the controllability in each scenario to be able to observe the changes in the network's operation. In scenario 2, the primary substation's on-load tap changer (OLTC) and the DG's reactive power control are activated. In scenario 3, in addition to all activated controllabilities (OLTC and DG's reactive power control), LFM as a CM solution is also utilised to see its impact.

### 3.1 Example system

Fig. 3 shows the topology of the under-study distribution system, including two voltage levels of 110 and 20 kV, a transformer with an OLTC located in the primary substation, DG and three aggregated loads in the medium voltage level. The primary substation's transformer regulates the voltage of bus 3 within a predefined dead band. The up set-point, down set-point, and the reference value of the voltage controller's dead band are 1.01, 1 and 1.005 p.u. The tap changer posses 32 tap steps with 0.00625 p.u. step size. The idea behind setting the OLTC's dead band at a slightly low level (usually the reference value is >1.005 p.u.) is to increase the hosting capacity of bus 5. The DG is a grid-connected 5 MW photovoltaic system. The parameters of the volt-var mode of the DG, including minimum limit, maximum limit, dead band and reference, are set 0.96, 1.04, 0.04 and 1 p.u. The 20 kV lines are assumed to have maximum ampacity of 130 A. The maximum and minimum allowed voltages for grid operation are 1.05 and 0.95 p.u. respectively. Fig. 4 represents load and generation profiles. Fig. 4*d* of the figure clearly shows the DG's output meets its peak around midday that is expected to be the source of congestion.

It should be stressed that the predictive simulations in DMS are done for the next day (next 24 h), considering that the time resolution of data is 15 min; therefore, 96 flow states representing a DA constitute the *x*-axis of all plotted graphs.

### 3.2 Scenario 1

In this scenario, the distribution system without any controllability is assumed, which can be considered the worst-case scenario from a controllability perspective. It means that the primary substation's transformer has a fixed tap position (tap step 12), and the DG is utilising the unity power factor. The voltage of buses 3, 5 and 6,

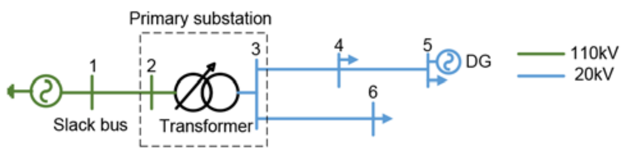


**Fig. 3** *Single-line diagram of the understudy distribution system*

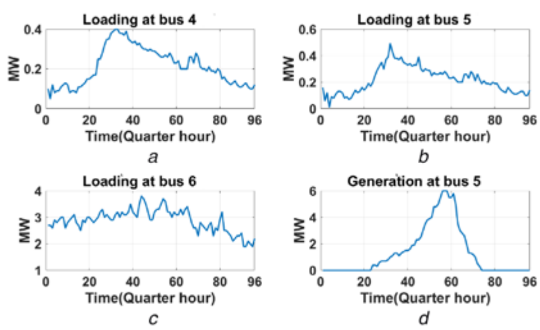


**Fig. 4** *Distribution network's supply and demand profiles*
**(*a–c*)** Network's loading, (***d***) DG's generation

and the tap position are shown in Fig. 5. Fig. 5*a* illustrates the voltage violation at bus 5 during the mid-day when the DG's output is close to its maximum. Fig. 6 illustrates the total active and reactive power losses of the network, DG's active and reactive power output, and loading of the lines between busses 3 to 6 and 4 to 5. The red dots in Fig. 6*f* highlight a current violation in the line between buses 4 and 5 which is the result of reverse power flow from bus 5 towards the primary substation. To sum up scenario 1, it clarifies the current problems (overvoltage at bus 5, overloading of the line between buses 4 and 5) that occur for the grid due to excess DG output around midday.

### 3.3 Scenario 2

In addition to the primary substation's OLTC, the volt/var mode of the DG connected to bus 5 has been activated in this scenario. As Fig. 7*a* illustrates, the intensity of voltage rise at bus 5 has been reduced (compared to the situation in scenario 1) considering that the DG's reactive power compensation has led to a slight rise in active and reactive power losses of the network as shown in Figs. 8*a* and *b*. Overloading of the line between buses 4 and 5 has slightly increased according to Fig. 8*f* due to reactive power compensation of the DG. It should be mentioned that whenever overvoltage at a bus coincides with the overloading of the nearby lines, reactive power compensation is not a good practice to relieve the overvoltage problem because it aggravates the overloading problem (especially if the power factor of the bus is close to unity). However, this scenario reduces the duration and intensity of overvoltage on bus 5; it introduces the under-voltage problem at bus 6 due to activating OLTC at the primary substation. In other words, the intention is to keep the reference value of OLTC's dead band at a slightly low level (1.005 p.u.) to increase the hosting capacity at bus 5, but it causes under-voltage problems for the adjacent feeder where bus 6 is fed from. Besides, the overloading intensity of the line between buses 4 and 5 has been increased because of the reactive power compensation of the DG. In general, in terms of duration and intensity of violations, scenario 2 has improved the situation, but it does not offer a complete solution.

### 3.4 Scenario 3

In this scenario, the target is to utilise non-market-based solutions (primary substation's OLTC and DG's volt/var control) and market-based solutions (LFM) and observe how the network's congestion is improved. The sequence of CM in this scenario starts with using non-market-based solutions followed by using LFM if it is needed. In other words, after taking non-market-based solutions, if the congestion persists, LFM is utilised to offer flexibility for the use of DSO. The used flexibility product is scheduled reprofiling (SRP) that is defined as 'the obligation of the flexibility to modify the demand or generation at a given time for the benefit of flexibility buyer' [3]. Since flexibility activation is

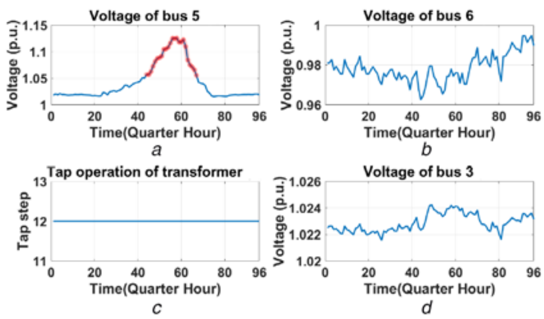


**Fig. 5** *Scenario 1*

***(a, b, d)*** Bus voltages, ***(c)*** OLTC's tap operation

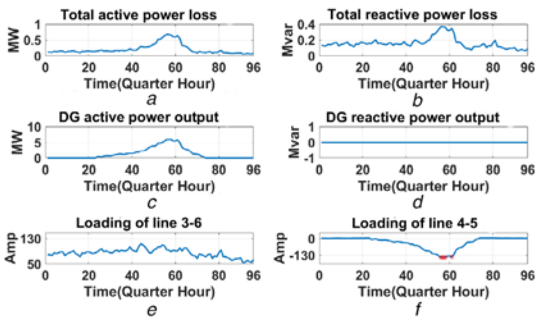


**Fig. 6** *Scenario 1*

***(a, b)*** Distribution network's losses, ***(c, d)*** DG's output, ***(e, f)*** Distribution network's loading

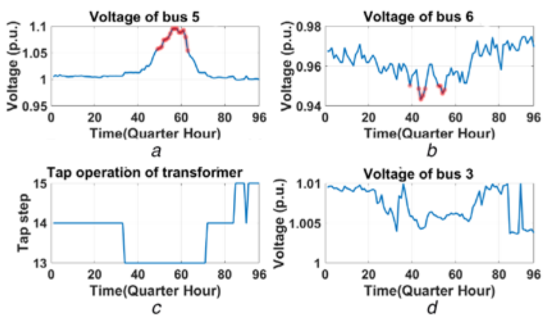


**Fig. 7** *Scenario 2*

***(a, b, d)*** Bus voltages, ***(c)*** OLTC's tap operation

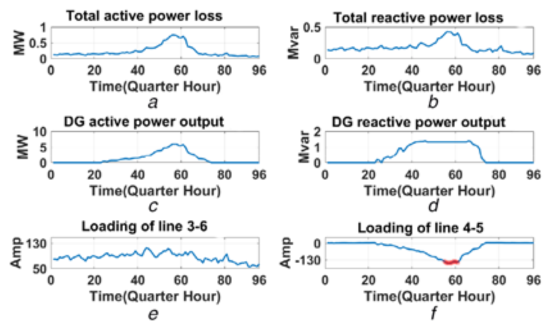


**Fig. 8** *Scenario 2*

***(a, b)*** Distribution network's losses, ***(c, d)*** DG's output, ***(e, f)*** Distribution network's loading

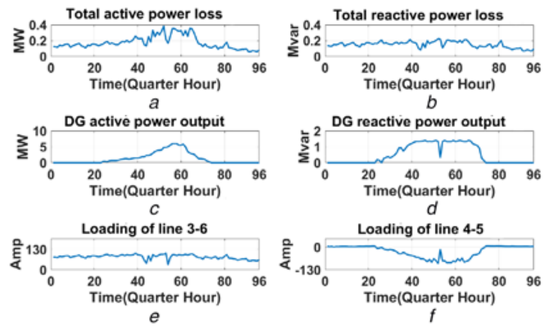


**Fig. 9** *Scenario 3*

***(a, b)*** Distribution network's losses, ***(c, d)*** DG's output, ***(e, f)*** Distribution network's loading

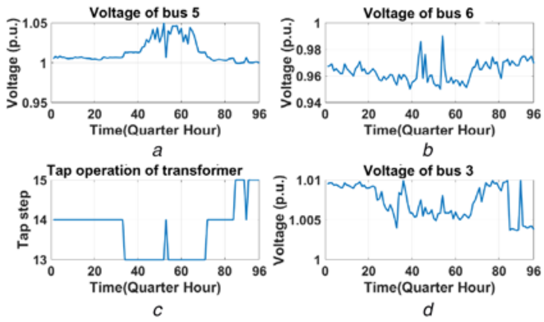


**Fig. 10** *Scenario 3*

***(a, b, d)*** Bus voltages, ***(c)*** OLTC's tap operation

included in the SRP product's price, a DSO prefers to use it first and then utilise other contrallabilities if needed. When flexibilities for the congested quarter hours are procured, it has been designed that, in real-time, the OPF uses the flexibilities for CM first because of using SRP, and second, it utilises non-market-based solutions; however, the mentioned sequence of using market and non-market-based solutions are not the only way for CM which can vary based on different parameters and considerations (i.e. flexibility product design). In fact, the non-market-based solutions act as a support for the procured flexibilities. Figs. 9 and 10 confirm that the procured flexibilities have been effective on congestion removal because neither voltage nor current violation is visible, so it can be claimed that the network status is in an acceptable state by combining market and non-market-based alternatives for CM of the under-study distribution network.

The work of Attar [3] contains the amount, location and direction of the used flexibilities as well as the network model data etc.

## 4 Conclusion

The paper introduced not only a theoretical but also a practical approach for CM by using a simulation environment that emulates the reality of the distribution system. By using the environment, it was shown that non-market-based solutions might not relieve congestion, and alternatives based on flexibility provision are needed. LFM timeframe was proposed and congestion was relieved by using the LFM market along with the non-market-based solutions.

## 5 Acknowledgments

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