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Impact of Grid Reconfiguration in Distribution Market Clearing and Settlement

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SUMMARY

The deployment of distributed energy resources (DERs) is rapidly increasing in distribution grids, supported by falling cost of the technology and various state and federal incentives. This proliferation is causing challenges in system operation, which is subsequently leading to proposals calling for distribution system operators (DSO) to be established and to be further in charge of the distribution system reliability, administer its operation, monitor a local energy market, and serve as an interface between the DERs and the upstream grid. In this paper, a distribution market clearing model is proposed to maximize the local social welfare while supporting grid reliability. This least-cost reliability-constrained objective is achieved through grid reconfiguration, i.e., a grid topology control. The model is verified by numerical simulations and the results confirm the added value of the reconfiguration in maximizing the system social welfare.

KEYWORDS

Distributed energy resource, distribution market, distribution system operator, grid reconfiguration.

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1. INTRODUCTION

Distributed energy resources (DERs), such as rooftop solar panels, energy storage systems and small-scale wind turbines, help increase the distribution system reliability and resiliency by allowing consumers to partially or fully supply their demand [1], while at the same time add technical complexity to grid management. This issue also exists in case of microgrids, as advanced technologies that integrate and manage several DERs and loads, resulted from their operation as proactive customers responsive to day-ahead price signals with uncertain net loads [2]. In either case, it has become evident that a distribution system operator (DSO) to manage the local distribution grid and solve this added complexity in a local manner is necessary. The necessity of the DSO in the distribution system is discussed in [3] and [4], along with the concerns of increasing penetration of proactive customers and their benefits and challenges in the distribution system. Figure 1 shows the role and market structure of the DSO. The DSO has many advantages for the distribution system including [5]:

1) Allowing the proactive customers to play a direct role in energy market within distribution system.
2) Removing the uncertainty of flexible loads on a day-ahead basis.
3) Forming a single point of contact between the ISO and proactive customers, which will significantly reduce the required two-way communications.

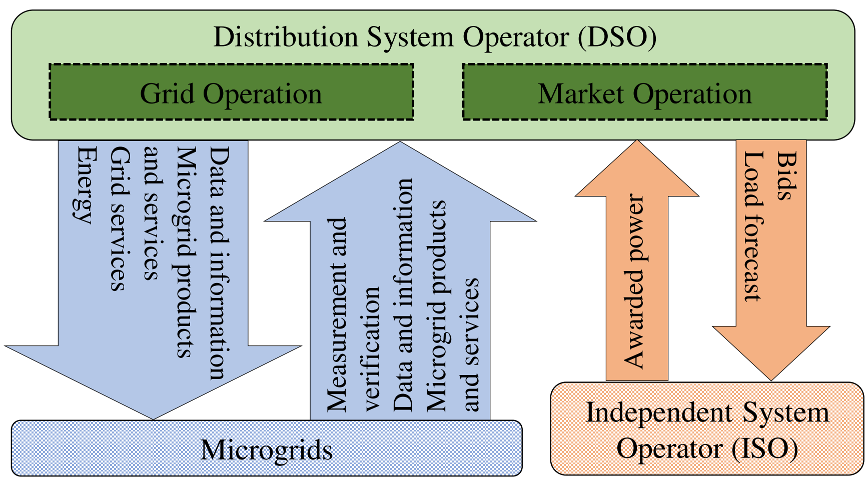

Figure 1: Market structure in presence of the DSO

The studies on DSO have been significantly increased over the past few years. Authors in [6] propose an optimal scheduling for microgrids based on market signal using distribution market operator (DMO). The DMO can establish an electricity market in distribution level and determine the amount of exchanged power among market participants on a day-ahead basis. Authors further expand their idea in [7] through a comparison between market-based and price-based microgrid optimal scheduling. It is shown that the market-based model improves the clearing process of the distribution market compared to the price-based model. An investigation of clearing and settlement of the distribution market is discussed in [8]. The DMO clears the distribution market and assigns the awarded power to flexible loads within its balancing area. Then, the distribution market would be settled by calculating the payment from each flexible load and the total payment to the DSO. In [9], authors investigate the DMO fairness to encourage proactive customers in participating in grid operations, which is obtained through an efficient pricing mechanism to achieve a net-zero settlement. The net-zero settlement means that the aggregated customers' payments is equal to the total payment by the DMO to the upstream grid/ISO. In [10], authors propose a day-ahead clearing market model in distribution system in which by using the distribution locational marginal pricing (DLMP), a price signal is provided to motivate DERs to help in congestion management and voltage support. Authors in [11] address the congestion management in the distribution system due to high penetration of renewable generation. A virtual power plant (VPP) concept is proposed as a service-centric aggregator to enable the integration of renewable energy sources in the distribution market and simultaneously support the DSO to perform congestion relief services.

This paper builds on the existing work in this area and focuses on maximizing the social welfare in the distribution market through grid reconfiguration. The rest of this paper is organized as follows: Section 2 presents the outline and formulation of the proposed model. Numerical analyses of the proposed model are provided in Section 3. Section 4 concludes the paper.

2. DISTRIBUATION SYSTEM CLEARING MODEL - OUTLINE AND FORMULATION

The proposed model aims at reconfiguring the distribution grid using the smart switches in order to maximize the system social welfare. The system social welfare is defined as the load benefit minus the cost of purchasing energy from the upstream grid (1).

$$\max\left(\sum_{i\in \mathrm{D_m}} B_i(P_i^{MG}) - \sum_{c\in \mathrm{C_m}} \lambda_c^T P_c^M\right) \tag{1}$$

where, i is the index for number of flexible loads, and or microgrids, in the distribution system and c is the index for the points of interconnection (POI) with the upstream grid. $B(.)$ represents the load benefit of flexible loads, i.e., the amount that customers are willing to pay for a desired level of power. λ^T and P^M represent the price and amount of power exchange with the upstream grid, respectively. The objective function is subject to operational and radiality constraints. Active and reactive power balance constraints are represented in (2) and (3), respectively, to ensure the supply-demand balance for all buses.

$$\sum_{c\in \mathrm{C_m}} P_c^M + \sum_{n\in \mathrm{B_m}} PL_{nm} + \sum_{i\in \mathrm{D_m}} P_i^{MG} = PD_m \qquad \forall m \tag{2}$$

$$\sum_{c\in \mathrm{C_m}} Q_c^M + \sum_{n\in \mathrm{B_m}} QL_{nm} + \sum_{i\in \mathrm{D_m}} Q_i^{MG} = QD_m \qquad \forall m \tag{3}$$

where, PL_{mn} and QL_{mn} represent the distribution line active and reactive power flow from bus m to bus n. P^{MG} and Q^{MG} are the flexible load active and reactive power, and PD_m and QD_m represent the fixed load active and reactive power. The line that connects the distribution grid to the upstream grid has a capacity limit as represented in (4). Similarly, the flexible loads need to be within certain operation limits as represented in (5) and (6).

$$-P_c^{M,\max} \le P_c^M \le P_c^{M,\max} \qquad \forall c\in \mathrm{C_m} \tag{4}$$

$$P_i^{MG,\min} \le P_i^{MG} \le P_i^{MG,\max} \qquad \forall i\in \mathrm{D_m} \tag{5}$$

$$Q_i^{MG,\min} \le Q_i^{MG} \le Q_i^{MG,\max} \qquad \forall i\in \mathrm{D_m} \tag{6}$$

The proposed model is developed using a linearized AC power flow. The details of linearization can be found in [12]. Active and reactive AC power flow equations are represented in (7) and (8), respectively. The distribution lines' capacity is modeled by (9) and (10) to impose active and reactive power flow limits.

$$-M(1-w_{mn}) \leq PL_{mn} - g_{mn}(\Delta V_m - \Delta V_n) + b_{mn}(\Delta\theta_m - \Delta\theta_n) - g_{mn}\Delta V_m(\Delta V_m - \Delta V_n) \leq M(1-w_{mn}) \quad \forall mn \in \mathrm{L} \tag{7}$$

$$-M(1-w_{mn}) \leq QL_{mn} + b_{mn}(\Delta V_m - \Delta V_n) + g_{mn}(\Delta\theta_m - \Delta\theta_n) + b_{mn}\Delta V_m(\Delta V_m - \Delta V_n) \leq M(1-w_{mn}) \quad \forall mn \in \mathrm{L} \tag{8}$$

$$-PL_{mn}^{\max} w_{mn} \leq PL_{mn} \leq PL_{mn}^{\max} w_{mn} \qquad \forall mn \in \mathrm{L} \tag{9}$$

$$-QL_{mn}^{\max} w_{mn} \leq QL_{mn} \leq QL_{mn}^{\max} w_{mn} \qquad \forall mn \in \mathrm{L} \tag{10}$$

where, M is a large positive number which is used to relax the power flow equations when the line is switched off, and w_{mn} is a state variable which is used to decide the state of distribution lines (w_{mn} is 1 when the switch is closed and 0 otherwise). When the state variable of the distribution line, i.e., w_{mn}, is 0, (9) and (10) force to switch off the line and make sure no power flows in that line, whereas (7) and (8) would be relaxed. On the other hand, the distribution line would be in service when $w_{mn} = 1$. Thus, the power flow limits (9) and (10) allow the power flow in the line and (7) and (8) would be forced. ΔV_m and $\Delta\theta_m$ are the variations in voltage magnitude and angle for each bus relative to the POI. The POI bus is considered as a reference bus with voltage magnitude of 1 pu and an angle of 0 degrees. These variations are constrained by (11) to make sure there will be no voltage violation in the distribution buses.

$$\Delta V_m^{\min} \leq \Delta V_m \leq \Delta V_m^{\max} \qquad \forall m \tag{11}$$

The radial structure of the distribution grid should not be affected by the grid reconfiguration. The term "radial structure" means that all nodes are connected but they do not form any loops. The radiality constraint (12) is added to make sure the distribution system stays radial and does not form loops.

$$\sum_{mn \in \Gamma} w_{mn} \leq L-1 \qquad \forall mn \in \mathrm{L} \tag{12}$$

where, L is the number of distribution lines in each possible loop. This constraint would force the number of closed lines to be one less than the number of lines that can form a loop. Hence, there should be one open line in each potential loop.

3. NUMERICAL SIMULATION

The proposed model is tested on a modified IEEE 33-bus distribution system shown in **Error! Reference source not found.**. This system consists of 33 buses, 32 sectionalizing switches (normally close), 5 tie switches (normally open), 29 fixed loads, and 3 microgrids. Closing any tie switch would form a loop. All potential loops are shown in **Error! Reference source not found.**. The proposed formulation is modeled by mixed integer linear programming (MILP) and solved using CPLEX 12.6. It is solved for only one-hour; however, it can be extended to be solved for any other selected time horizon, including day-ahead. The total fixed load is 2620 kW, and the generation capacity of each microgrid is 1000 kW. The market price at the POI is $0.070/kWh. The fixed load of microgrids 1, 2, and 3 at this selected hour are 63.379 kW, 296.204 kW, and 42.427 kW, respectively. Table 2 shows the microgrids characteristics. The proposed model is solved for two cases with and without grid reconfiguration to show the impact on the results.

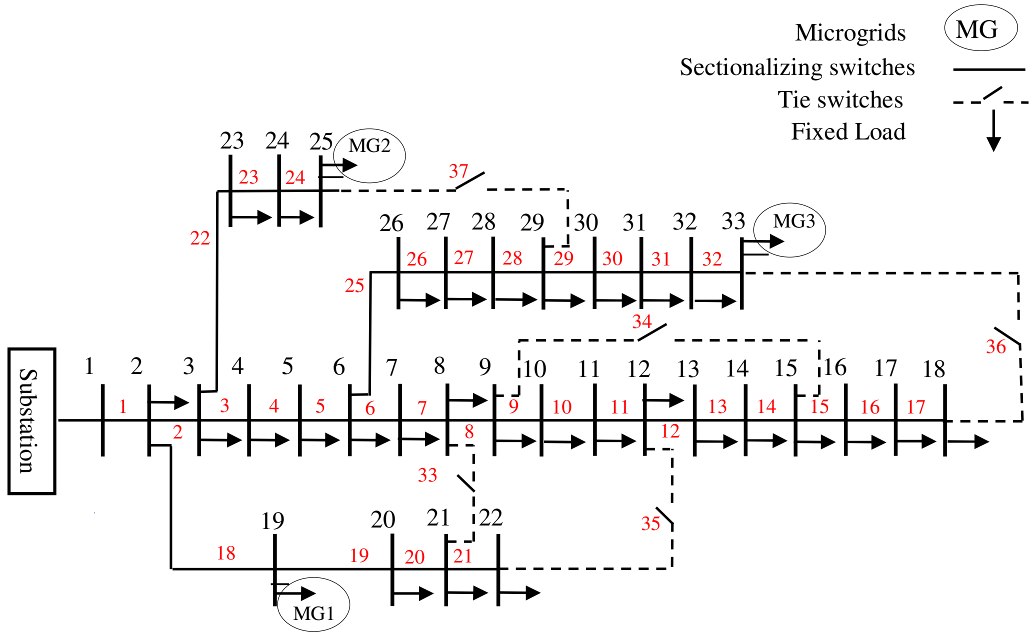

Figure 2: The IEEE 33-bus distribution test system

Table 1: The potential loops

Loop No.	Lines in the loop
1	2, 3, 4, 5, 6, 7, 18, 19, 20, 21, 33
2	9, 10, 11, 12, 13, 14, 34
3	2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 18, 19, 20, 21, 35
4	6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 25, 26, 27, 28, 29, 30, 31, 32, 36
5	3, 4, 5, 22, 23, 24, 25, 26, 27, 28, 37

Table 2: Microgrids' Characteristics

Segments	1		2		3	
	Quantity (kW)	Price ($/kW)	Quantity (kW)	Price ($/kW)	Quantity (kW)	Price ($/kW)
Microgrid 1	500	0.065	300	0.039	200	0.027
Microgrid 2	450	0.072	350	0.065	200	0.029
Microgrid 3	400	0.085	400	0.064	200	0.035

Case 1: Without grid reconfiguration: In this case, the proposed model is solved for a one-hour period without allowing any changes in the grid topology. This is achieved by forcing all tie switches to stay open by fixing the state variable w_{mn}=0. The social welfare is calculated as $150.54. The total power purchase from the upstream grid is 1233.09 kW. Microgrids 1, 2, and 3 generate 703.949 kW, 600 kW, and 142.418 kW, respectively. The total power loss is calculated as 59.46 kW. In this case, the payment to the upstream grid is $86.32, and the customers' payment to the DSO is $183.88.

Case 2: With grid reconfiguration: In this case, the grid reconfiguration is considered in the proposed model. This is accomplished by allowing the state variables of the tie and sectionalizing switches to change (to either 0 or 1) in the optimization problem. In this case the optimal grid reconfiguration is achieved by closing 2 tie switches (36 and 37) and simultaneously opening 2 sectionalizing switches (15 and 22) to prevent forming loops in the distribution system. The social welfare is increased in this case to $153.56, which is more than the previous case by 2%. The total power purchase from the upstream grid is 616.76 kW, which is decreased by 49.98% compared to previous case. In this case microgrids 1, 2, and 3 generation are increased by 7.1%, 66.67%, and 104.16%, respectively. The total power loss is decreased by 30.26% compared to the previous case, reaching 41.47 kW. Moreover, the payment to the upstream grid in this case is $43.17, which is decreased by 49.98%. However, the customers' payment to the DSO is increased by 1.02% to $185.76. The upstream grid payment is decreased as the power purchase from the upstream grid is dropped, and instead power is purchased locally from microgrids to maximize the system social welfare. As a result, microgrids generation is increased in in this case compared to Case 1. **Error! Reference source not found.** and **Error! Reference source not found.** compare the market clearing and power flow results in Cases 1 and 2, respectively.

Table 3: Comparison between results of Cases 1 and 2

		Without Reconfiguration	With Reconfiguration	Change
Social Welfare ($)		150.54	153.56	2%
Upstream power purchase (kW)		1233.09	616.76	-49.98%
Microgrids power (kW)	MG1	703.949	753.949	7.1%
	MG2	600	1000	66.67%
	MG3	142.418	290.765	104.16%
Power Loss (kW)		59.46	41.47	-30.26%
Upstream grid payment ($)		86.32	43.17	-49.98%
Customers payment ($)		183.88	185.76	1.02%

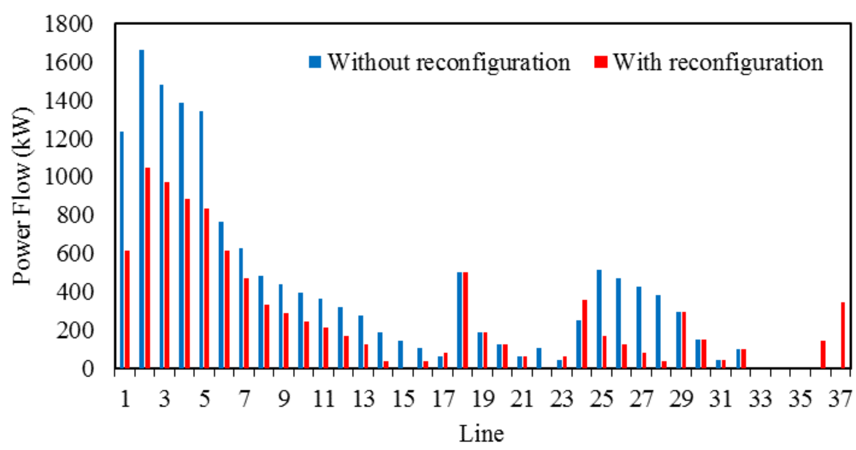

Figure 3: Power flow comparison between cases 1 and 2

As shown in **Error! Reference source not found.**, the power flow when reconfiguration is not considered is high for most of the lines compared to the case with reconfiguration. This is because of the opportunity that is provided for local generators, within microgrids, to supply local loads and change the grid power flow. This change in power flow also helps reduce the power loss as shown in the results.

4. CONCLUSION

A grid reconfiguration model was proposed seeking to maximize the social welfare in a distribution market. The proposed model was formulated by MILP and tested on a modified IEEE 33-bus distribution system. The results showed that the social welfare could be improved by applying the grid reconfiguration. Moreover, the proposed model showed the capability to serve as a congestion relief and loss reduction method by revising the power flow within the grid. Overall, the model advocated that the reconfiguration can provide a level of flexibility in distribution markets to improve the system social welfare and help with better utilization of distributed resources within radial distribution grids.

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