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Optimal deployment of feeder remote terminal units in distribution networks to improve power supply reliability

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Abstract

Deploying feeder remote terminal units (FRTUs) in the distribution network and then integrating them into existing manual switches (MSs) can facilitate automatic locating of faulted sections and rapid isolation from faults to improve the power supply reliability. However, the fault management process, including fault location, fault isolation, and service restoration, is usually simplified in traditional FRTUs deployment methods. In particular, the fault isolation and service restoration operations are usually modeled individually without considering the FRTUs operation during the whole fault management process in these traditional methods. In this paper, the FRTUs in the potential service restoration paths for the customers are ruled out to avoid unnecessary power outage, and the effect of FRTUs operation on the fault management process is analyzed and discussed in branched distribution networks. Secondly, a quantification analysis model considering FRTUs operation is built to obtain the accurate interruption time of the distribution network. Thirdly, the quantification model is used to obtain the revenue generated by interruption cost reduction for the deployed FRTUs. Finally, an optimal deployment model of FRTUs in mixed-integer nonlinear format is constructed and solved efficiently by the software LocalSolver, which combines heuristic techniques and stochastic search algorithms. The new method is compared with the traditional FRTUs deployment method in the CSG 53-node test system, and the results show that the proposed method can achieve greater return on investment and higher power supply reliability.

Keywords: Feeder remote terminal unit; Distribution networks; Fault management process; Optimal deployment; Fault isolation; Service restoration

1. Introduction

As an important part of the power system [1], the distribution network [2] directly distributes the electrical energy to all kinds of customers to meet their service needs. Establishing an automated distribution network [3] by deploying automation equipment can accelerate the fault management process [4] to shorten the interruption

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Nomenclature

W_t	Set of years
W_f	Set of all feeders
W_i	Set of all possible fault positions
$W_{i,main}$	Set of fault positions on main feeder lines
$W_{i,late}$	Set of fault positions on lateral lines
W_j	Set of all customers
$W_{f,j}$	Set of customers in feeder f
W_X	Set of all locations at switches
W_K	Set of all types of customers
$SP_{B,C}$	Set of fault positions between reserve power supply and circuit breaker
$SP_{j,B}$	Set of fault positions between customer j and circuit breaker
$S_{f,C,j}$	Set of locations at switches on lines between customer j and reserve power supply in feeder f
$S_{f,B,j}$	Set of locations at switches on lines between customer j and circuit breaker in feeder f
$S_{f,i,j}$	Set of locations at switches on lines between customer j and fault position i in feeder f
D	Discount rate
h	Percentage of maintenance cost expenses to the installation cost
t_{MS}^{iso}	Time to isolate faults by manual switch
ε	The smallest number
t^{loc}	Average fault location time
t^{res}	Restoration time
t_{main}^{rep}	Fault repair time of components on the main feeder lines
t_{late}^{rep}	Fault repair time of components on lateral lines
t	Equipment life cycle
CI_{FRTU}	Installation cost of FRTU
CI_{EOM}	Installation cost of EOM
C_{tot}	Total cost
C_{int}	Interruption cost
C_{equ}	Equipment cost
C_{ins}	Equipment installation cost
C_{main}	Equipment maintenance cost
$C_{t,f,i,j,k}$	Interruption cost for the customer with type k at load point j after a fault at position i in feeder f in year t
$CDF_{t,f,i,j,k}$	Customer damage function for the customer with type k at load point j after a fault at position i in feeder f in year t
N_{FRTU}	Number of FRTUs
N_{S-FRTU}	Number of FRTUs in distribution substation S
N_{EOM}	Number of EOMs
$P_{t,f,j,k}$	The load of the customer with type k at load point j in feeder f in year t
$\lambda_{f,i}$	Failure rate of line i in feeder f
$T_{f,i,j}$	Interruption time of customer j after a fault occurring at position i in feeder f

time for customers and improve service reliability. Among many kinds of automation equipment, the feeder remote terminal unit (FRTU) [5] gets the most attention from electric companies. The FRTU is usually integrated with the manual switch (MS) [6], and these MSs are turned into remote-controlled switches (RCSs) [7]. The RCSs can speed up the process of fault location, fault isolation, and service restoration [8]. Therefore, the nature of the optimal deployment of RCSs in the distribution network is essentially the same as that of FRTUs in a newly-built distribution network. Furthermore, optimal deployment of FRTUs can also be used to upgrade an existing distribution network with MSs and RCSs. It is meaningful to conduct in-depth research on the optimal deployment of FRTUs in the distribution network. Numerous papers have been published in the field of optimal deployment of similar types of this automation equipment.

Various heuristic algorithms have been used to solve the optimal deployment problem of automation equipment in distribution networks. In Ref. [9], integer codes were used to represent the deployment of RCSs, and the initial population was then formed. Furthermore, the selection, crossover, and mutation operations were performed on the population so that the optimal individual (optimal solution) satisfying the fitness function (the objective function of the deployment model) was evolved generation by generation. The Ref. [10] used the differential search algorithm to solve a multi-objective optimization model that minimizes the outage cost and the economic equipment cost, respectively, and thus obtained the number and location of RCS deployment. In addition, particle swarm optimization [11], immune algorithm [12], and ant colony algorithm [13] have been applied to solve the optimal deployment model of automation equipment, respectively. On the other hand, algorithms in the field of operations research [14] are also widely used. A mixed-integer linear programming model was constructed to obtain the optimal position and number of RCSs, and this model was solved by commercial software [15]. To improve the reliability of the cyber–physical distribution system [16], the deployment of FRTUs in two scenarios of overhead feeders and underground cables in [17] was considered. It is assumed that automated devices always work properly in the above literature, but obviously, it is not practical. Hence the failure probability of the switch was integrated into the placement model in [18,19]. Finally, it was found that considering the failure probability of the equipment would lead to a smaller number of optimized equipment than not considering the failure probability of the equipment itself. Ref. [20] developed the mixed integer programming (MIP) model and considered the neglected influence of financial risk [21] on the configuration results. Ref. [22] considered the impact of distributed generation penetration on the sectionalizing switches configuration.

The above literature review shows that it is feasible to obtain the optimal deployment scheme via balancing equipment investment and interruption cost. The interruption time caused by the fault is closely related to the implementation of the fault management procedure. However, the analysis of the fault management process with FRTU involvement in the above works is not sufficiently refined. Specifically, the coupling between the fault isolation operation and the customer's service restoration process is ignored. This may result in the customer not being able to successfully obtain service from the main power supply or reserve power supply after isolating it from the fault with the help of FRTU. Furthermore, since the FRTU on the path between the customer and fault position may locate on the path between the customer and the power source, opening the FRTU used to isolate the fault would cause the outage of the customer.

With that in mind, in the analysis of the fault management process, all possible restoration paths for the customer are especially considered in conjunction with the selection of switches used for fault isolation operation in the fault isolation process in this paper. A more realistic determination of whether the customer can be isolated from the fault without going through the fault location process can be achieved. This refined analysis method of the fault management process resulted in the FRTU optimization deployment mathematical model based on cost–benefit analysis in a mixed-integer nonlinear format. This model can be solved by the LocalSolver [23], which combines heuristics and exact algorithms. The simulation results on the CSG 53-node test system verify the effectiveness of the proposed model and method.

The rest of this article is structured as follows. The deployment model of FRTU is discussed and constructed in Section 2. In Section 3, the proposed FRTU deployment method is analyzed and verified in the test system with corresponding sensitivity analysis. Finally, the conclusion is given in Section 4.

2. FRTUs deployment model

2.1. Basic FRTUs deployment model

In (1), the sum of equipment cost of FRTUs and customers interruption cost are expected to be minimal.

$$\text{Minimize } C_{tol}(x) = C_{int}(x) + C_{equ}(x) \tag{1}$$

where $C_{int}(\cdot)$ and $C_{equ}(\cdot)$ denote the interruption cost of customers and the equipment cost, respectively. The interruption cost can be calculated by

$$C_{int}(x) = \sum_{t\in W_t}\sum_{f\in W_f}\sum_{i\in W_i}\sum_{j\in W_j}\left[\frac{1}{(1+D)^t}\lambda_{f,i}\times T_{f,i,j}(x)\times\sum_{k\in W_k}P_{t,f,j,k}\times C_{t,f,i,j,k}(x)\right] \tag{2}$$

where, $C_{t,f,i,j,k}$ $(\cdot)$ represents the customer interruption cost and is the function of $T_{f,i,j}(\cdot)$. It can be described as

$$C_{t,f,i,j,k}(x) = CDF_{t,f,i,j,k}(T_{f,i,j}(x)) \tag{3}$$

where, $CDF_{t,f,i,j,k}(\cdot)$ is the customer damage function.

The life-cycle equipment cost of FRTUs can be described as

$$C_{equ}(x) = C_{ins}(x) + C_{main}(x) \tag{4}$$

where, $C_{ins}(\cdot)$ and $C_{main}(\cdot)$ are respectively the installation and maintenance costs, can be obtained by (5) and (6), respectively.

$$C_{ins}(x) = N_{FRTU}(x)\cdot CI_{FRTU} + N_{EOM}(x)\cdot CI_{EOM} \tag{5}$$

$$C_{main}(x) = \sum_{t\in W_t}\frac{1}{(1+D)^t}h\cdot\left[N_{FRTU}(x)\cdot CI_{FRTU} + N_{EOM}(x)\cdot CI_{EOM}\right] \tag{6}$$

where $N_{EOM}(\cdot)$ and $N_{FRTU}(\cdot)$ denote the numbers of electric operation mechanisms (EOMs) and FRTUs, respectively.

Since one FRTU deployed in a distribution substation can control all MSs installed EOMs on both sides of this substation, the number of FRTU in substation node S is 0 or 1, and the calculation is as follows:

$$N_{S-FRTU}(x) = 1 - \prod_{k\in S}(1 - x_k) \tag{7}$$

N_{EOM} (x) is calculated as:

$$N_{EOM}(x) = \sum_{k\in W_X} x_k \tag{8}$$

The binary variable x_k can be described as:

$$x_k = \begin{cases} 1 & \text{if switch } k \text{ is integrated with a FRTU} \\ 0 & \text{otherwise} \end{cases} \tag{9}$$

2.2. Calculation for interruption time

In the distribution network, the faults that can lead to the service interruption could occur on the main feeder line or the lateral line where the customer is located.

Fig. 1(a) depicts the distribution network of FRTUs to be deployed. The MS controlled by the FRTU is regarded to have the same functions as RCS, that is, fault current detecting and automatic fault isolation. First, assume that the fault occurs on the main feeder, as shown in Fig. 1(b). The presence of an RCS on the path between the customer and the fault position indicates that the fault is not downstream of the RCS, and this customer can be isolated from the fault by this RCS without enduring fault location time and obtain services from the reserve power supply. However, in Fig. 1(c), the reserve connection point is not the most downstream of the feeder. This RCS cannot be used for isolation because this RCS is also located on the path where the customer obtains service from the reserve power supply. In this case, the fault can only be isolated with the help of other MSs after the fault is accurately located. In summary, two factors must be considered in combination with all customers' service restoration paths: (1) Whether the customer can be isolated from the fault without waiting for the fault to be accurately located, and (2) the selection of the switch to perform the isolation operation.

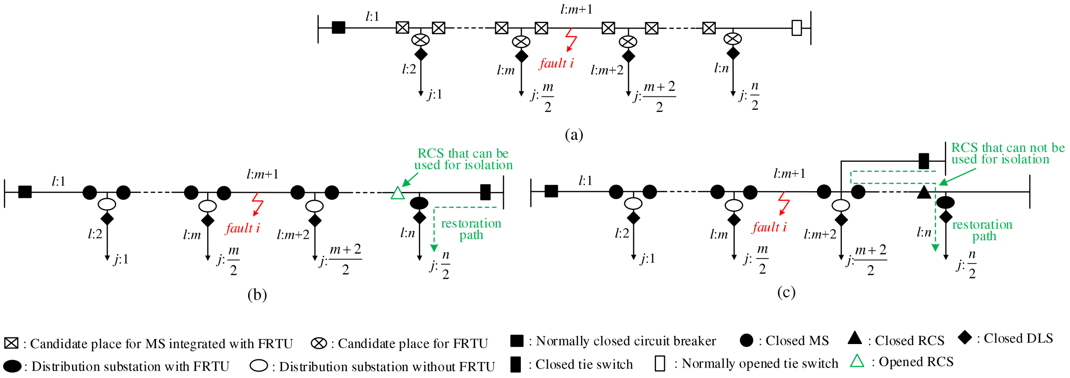


Fig. 1. An example distribution network for calculation of interruption time when a fault occurs on the main feeder line: (a) a fault occurs on the feeder; (b) RCS that can be used for isolation; (c) RCS that cannot be used for isolation.

Based on the above analysis, as a fault occurs on the main feeder line, the interruption time of customers upstream and downstream of the fault can be calculated by (10) and (11), respectively.

$$T_{f,i,j}(x) = t^{loc} \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,C,j}} (1-xk) \cdot \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,B,j}} (1-xk) + t^{iso}_{MS} \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,C,j}} (1-xk) \cdot \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,B,j}} (1-xk) + \varepsilon + t^{res}$$
$$\forall f \in Wf,\ i \in W_{i,main},\ i \notin SP_{j,B},\ j \in W_{f,j} \tag{10}$$

$$T_{f,i,j}(x) = t^{loc} \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,C,j}} (1-xk) + t^{iso}_{MS} \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,C,j}} (1-xk) + \varepsilon + t^{res}$$
$$\forall f \in W_f,\ i \in W_{i,main},\ i \in SP_{B,C},\ i \in SP_{j,B},\ j \in W_{f,j} \tag{11}$$

In addition, if the customer is downstream of the fault and there is no reserve power supply downstream, this customer has to wait until the fault is repaired before resuming service. Thus,

$$T_{f,i,j}(x) = t^{loc} + t^{rep}_{main} + t^{res} \qquad \forall f \in W_f,\ i \in W_{i,main},\ i \notin SP_{B,C},\ i \in SP_{j,B},\ j \in W_{f,j} \tag{12}$$

When a fault occurs on the lateral line, as in Fig. 2, the difference with the failure on the main feeder is the calculation for the time required for fault isolation. Due to the presence of a demarcation load switch (DLS) on the lateral where the customer is located, the customer who needs to experience the fault location process can be isolated from the fault by the DLS on the faulted lateral line. The customer who does not need to endure the fault location time can rely on the RCS for the isolation from the above analysis. Since the times required to operate them are all very short, it is assumed that the two times are equal for simplicity. Besides, note that only the customer on the faulty lateral line has to go through the fault repair process at this point.

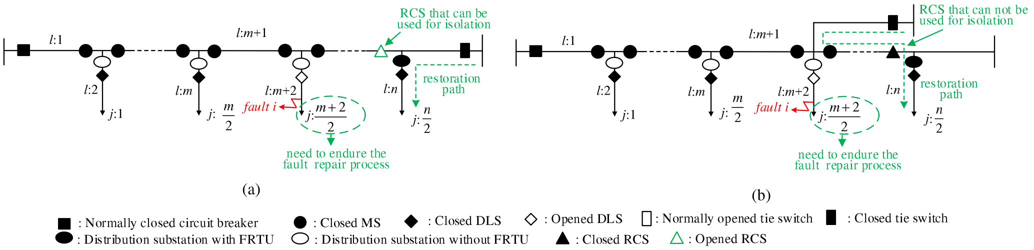


Fig. 2. An example distribution network for calculation of interruption time when a fault occurs on lateral lines in feeder f: (a) RCS that can be used for isolation; (b) RCS that cannot be used for isolation.

Then, the interruption time of customers upstream and downstream of the fault can be calculated by (13) and (14), respectively.

$$T_{f,i,j}(x) = t^{loc} \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,C,j}} (1 - xk) \cdot \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,B,j}} (1 - xk) + \varepsilon + t^{res}$$

$$\forall f \in W_f, i \in W_{i,late}, j \neq i/2, i-1 \notin SP_{j,B}, j \in W_{f,j} \tag{13}$$

$$T_{f,i,j}(x) = t^{loc} \prod_{\substack{k\in Sf,i,j \\ k\notin Sf,C,j}} (1 - xk) + \varepsilon + t^{res} \quad \forall f \in W_f, i \in W_{i,late}, j \neq i/2, i-1 \in SP_{j,B}, j \in W_{f,j} \tag{14}$$

Eq. (15) corresponds to the customer on the faulted line who needs to endure the fault repair process.

$$T_{f,i,j}(x) = t^{loc} + t^{rep}_{late} + t^{res} \quad \forall f \in W_f, i \in W_{i,late}, j = i/2 \tag{15}$$

Finally, as shown in (16), customers who are not on the same feeder as the fault are not affected by this fault.

$$T_{f,i,j}(x, y) = 0 \quad \forall f \in W_f, i \in W_i, j \notin W_{f,j} \tag{16}$$

3. Case study and discussions

To demonstrate the method and optimal allocation model of FRTUs in distribution networks proposed in Section 2, the simulation results on the CSG 53-node test system of the State Grid in China are obtained and analyzed in the following. Specifically, the objective function as shown in (1) calculated from (2)–(16) is organized by LocalSolver into a standard mixed-integer nonlinear mathematical model, which is then solved with the help of heuristic techniques and nonlinear programming methods to arrive at the solution.

3.1. CSG 53-node test system

The CSG 53-node test system [24] was developed by the State Grid Corporation according to the typical structure characteristics of China's distribution network. As shown in Fig. 3, the CSG 53-node test system, consisting of six main feeders, serves customers at 50 load points within the system. Specifically, the customer's service at each load point is distributed by a distribution substation located on the lateral line. In addition to the 50 main feeder lines, three tie lines can make three electrical energy transfers between different feeders. The load and type of each customer and the length of each line in the distribution system are given in [24]. The customer damage function is given by [25]. The operation time of manual switch and remote-controlled switch is 1.5 h and 0.02 h, respectively. The average fault location time is 0.7 h, and restoration time is 0.02 h. The fault rate and the repair time of the line and the distribution transformer are 0.042 (f/y· km), 0.012 (f/y), and 5.5 h, 4 h, respectively. The full life cycle of the equipment is set as 10 years. Each FRTU and EOM costs \$ 5000 and \$ 1000 to install, respectively. The load growth rate, discount rate, and ratio of maintenance cost to installation cost are 1.1%, 4%, and 3%, respectively.

3.2. Simulation results of FRTU deployment

The results of two cases without and with FRTU deployment in the CSG 53-node test system are given in Table 1. In Case I, no FRTUs are deployed, the corresponding fault interruption cost equals k\$ 115.92, and the reliability index of the whole system equals 99.9790%. In Case II, thirteen FRTUs are deployed in the locations given in Table 2. Although the equipment cost of deployed FRTUs equals k\$ 10.40, the corresponding fault interruption cost only equals k\$ 70.99 because the reliability index of the whole distribution system increases to 99.9883%. Therefore, the total cost for Case II equals k\$ 81.39, while the total cost for Case I equals k\$ 115.92. The total cost is reduced by k\$ 34.53, almost 29.8%. In addition, the value of the average service availability index (ASAI) increases by 0.0093%, i.e., the average annual interruption time of all customers decreased by about 40.73 h. It can be seen that the fault interruption cost and the total cost are reduced significantly after deploying FRTUs based on the proposed methods.

Table 2 lists the detailed deployed locations of FRTUs in Case II. 13 FRTUs are installed along Feeders F1, F2, F3, F4, and F5. The number of deployed FRTUs on these feeders equals 6, 4, 1, 1, and 1, respectively. Because one FRTU can be used to control several MSs, the number of the switches controlled by these deployed FRTUs reaches eighteen. For example, six FRTUs on Feeder F1 are installed on the positions labeled as 3, 4, 5, 6, 7, and 8. Eight MSs, numbered by 3E, 4E, 5E, 6E, 7E, 8E, 9B, and 10B, can be controlled by these six FRTUs.

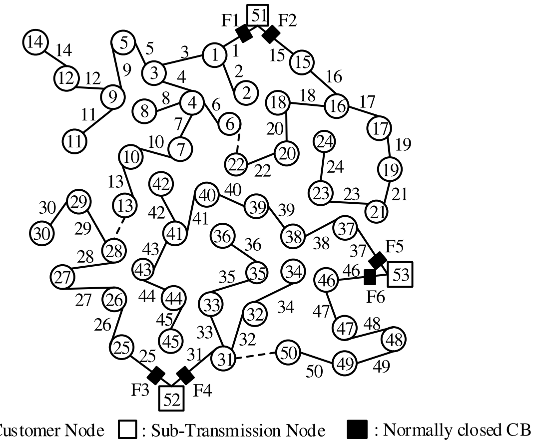


Fig. 3. CSG 53-node test system.

Table 1. Simulation results of FRTUs deployment in the CSG 53-node test system.

Case	Costs [k$]		Reliability index	
	Equ.	Int.	Total	ASAI (%)
I	0	115.92	115.92	99.9790
II	10.40	70.99	81.39	99.9883

Equ. : Equipment cost of FRTUs; Int. : fault interruption cost.

Table 2. Deployment locations of FRTUs in Case II.

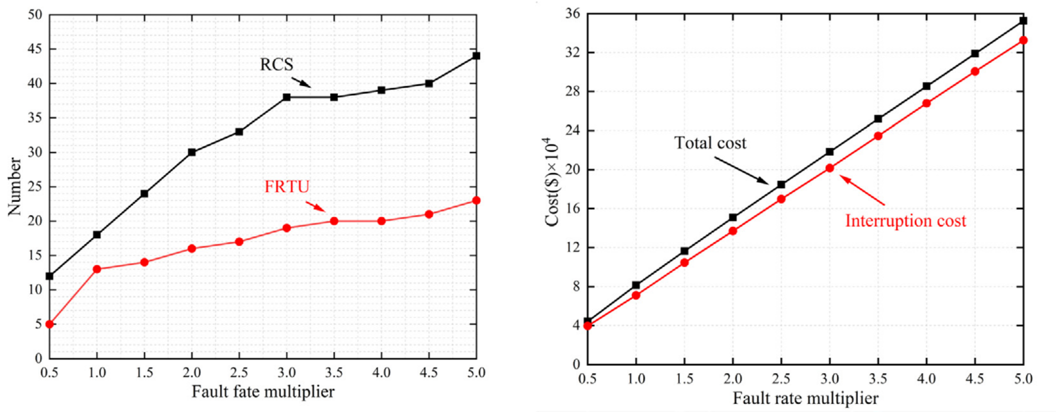
Feeder	Deployment scheme	
	FRTUs	Switches controlled by deployment FRTUs
F1	3, 4, 5, 6, 7, 8	3E, 4E, 5E, 6E, 7E, 8E, 9B, 10B
F2	16, 17,18, 21	16E, 17E,18E, 20B, 23B
F3	27	28B
F4	31	31E, 32B, 33B
F5	40	41B
F6	–	–

The location of FRTU: The lateral line to which the corresponding numbered customer node is connected;
The location of switch: The main feeder line with the corresponding number;
B: Upstream side of the main feeder line; E: Downstream side of the main feeder line.

3.3. Sensitivity analysis on component fault rate

There is no doubt that the fault rate of each component in the power distribution system directly reflects the frequency of failure, which in turn has a direct impact on customer service reliability. So it is essential to simulate in advance the variation of the associated costs and the number of deployments with different fault rates. Fig. 4(a) and (b) respectively show the changes in equipment numbers and system costs when the fault rate changes from 0.5 times the initial value to 5 times the initial value.

From Fig. 4(a), it is known that the number of FRTUs and RCSs are both strictly increasing when the fault rate becomes higher. The number of RCSs is always larger than the number of FRTUs, and this is because one FRTU located in a distribution substation can be integrated with multiple MSs and make them RCSs. It can be seen from Fig. 4(a) that as the fault rate increased to 4.5 times the initial value, the number of FRTUs and RCSs increased by 16 and 28, respectively. It is not difficult to think that as the frequency of fault rate increases, the number of interruptions increases. In this case, FRTUs in the distribution system can reduce the time needed for locating faults



(a) (b)

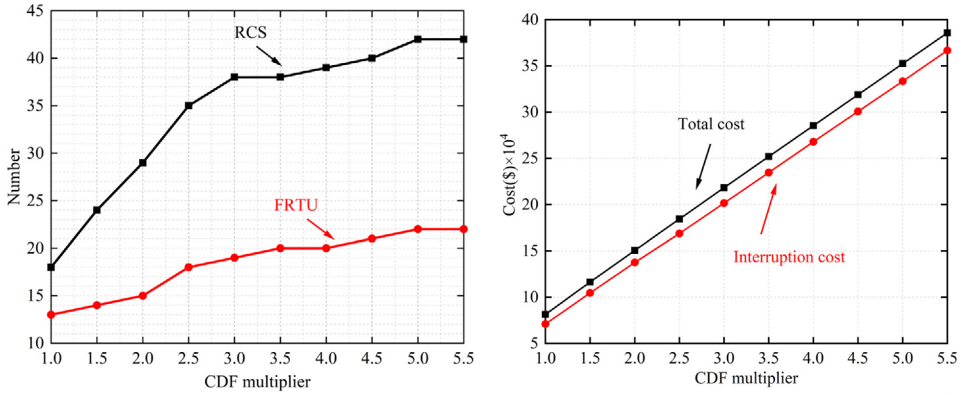
Fig. 4. The deployment results related to the fault rate: (a) The FRTUs deployment numbers for different component fault rates; (b) The system costs for different component fault rates.

and isolating faults. However, Fig. 4(b) shows that even with the increase in the number of FRTU deployments, the customer's fault interruption cost and the total system cost are still rising, increasing by about k$ 326.3 and k$ 341.6 respectively during the whole change process.

The above trends show that the growth in the fault rate inevitably leads to an increase in all system costs, so it makes sense to maintain the components of the distribution system to avoid this outcome as much as possible.

3.4. Sensitivity analysis on customer damage function

The customer damage function (CDF) directly determines the interruption cost due to failure for various kinds of customers. Therefore, before the CDF is formulated, it is required to simulate and analyze the impact on the number of equipment deployed and associated costs when its value changes. Fig. 5(a) indicates that when the CDF is increased to 5.5 times of the initial value, the number of FRTUs and RCSs increases by about 69% and 133%, respectively. In addition, the change of costs in Fig. 5(b) shows an upward trend, it can be seen that interruption costs account for most of the total cost, and they have increased by about k$ 295.6 and k$ 304.3, respectively. All these variations can provide valuable references for developing CDF functions and the deployment of FRTUs.

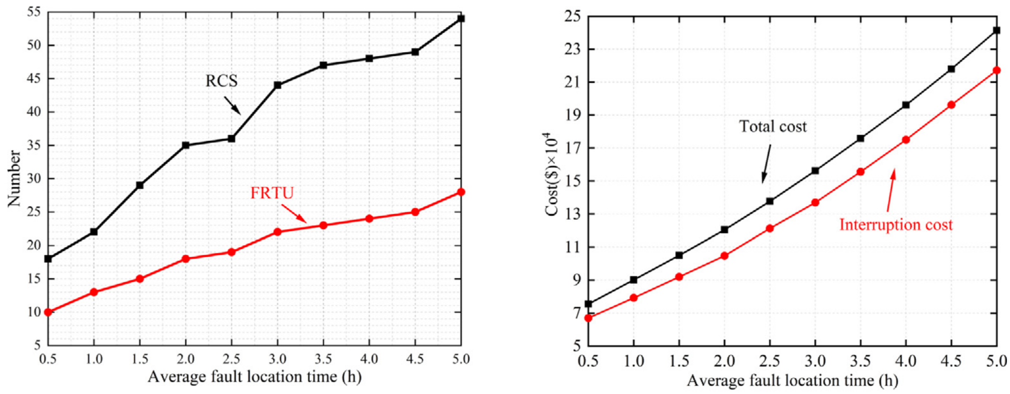


(a) (b)

Fig. 5. The deployment results related to the customer damage function: (a) The FRTUs deployment numbers for different CDFs; (b) The system costs for different CDFs.

3.5. Sensitivity analysis on average fault location time

For customers who need to experience the fault location process, the average fault location time is also a major part of their fault interruption time. The simulation results for fault location times between 0.5 and 5 h are presented in Fig. 6(a) and (b). Within this range, the number of FRTUs and RCSs increased by 18 and 36, respectively. In addition, the number of RCSs changed more sharply than that of FRTUs. The more average fault location time, the easier it is for customers to have their interruption time reduced with the help of FRTUs. Therefore, it is reasonable to invest more FRTUs to increase the service reliability to a greater extent. However, in Fig. 6(b), the interruption cost increases by about k$150.2, ultimately resulting in a total cost increase of about k$ 166.0. This indicates that the increase in interruption cost caused by each change in fault location time is still higher than the sum of the new equipment investment cost and the interruption cost that can be improved after the equipment is invested.



(a) (b)

Fig. 6. Deployment results related to the average fault location time: (a) Deployment numbers for different average fault location times, (b) System costs for different average fault location times.

3.6. Simulation results for different numbers of deployed FRTUs

The cost of equipment that an electric utility can afford directly determines the number of FRTUs that can be deployed in the distribution system. Fig. 7 shows the cost variation associated with FRTU for different deployment numbers. Because the number of FRTUs increases one by one, it leads to an approximate directly proportional relationship between the equipment cost and the number of FRTUs. The interruption cost caused by faults decreases as the number of FRTU deployments increases, while the magnitude of the change reduces. This trend leads to an optimal number of deployments by weighing the equipment and the interruption costs, as shown in Fig. 7. Specifically, the total cost of the system is minimal when the number of FRTU deployments is 13. In other words, as the number exceeds 13, the equipment cost of new input brought by each change is greater than the change of interruption cost. However, in any case, the sum cost of installing and maintaining FRTUs is less than the interruption cost.

3.7. Comparison of results in different fault management process analysis methods

In this paper, the coupling effect between the implementation of the fault isolation process and the restoration process is considered in the modeling process of Section 2, while this effect is usually ignored in traditional methods. The comparison results are shown in Tables 3 and 4.

In Table 3, the number of deployed FRTUs equals thirteen in the proposed method compared to ten in the traditional method. Nevertheless, the total revenue equals k$ 34.53 in the proposed method, while the total revenue equals k$ 33.14 in the traditional method. The total revenue is increased by 4.2%. In the meantime, the reliability index of the whole system is increased by 0.0007%.

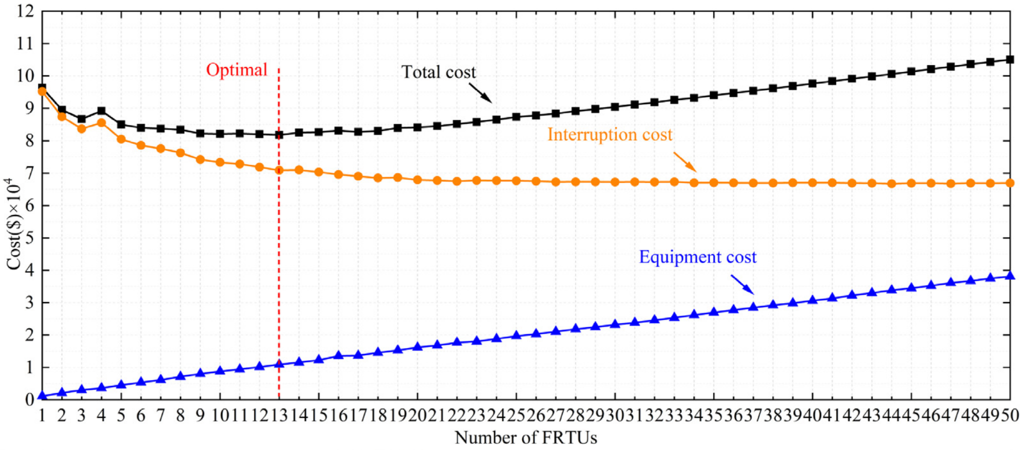


Fig. 7. The simulation results for different numbers of FRTUs deployed.

Table 3. The FRTUs deployment results in different methods.

Methods	FRTU deployment number	Revenue* [k$]	Reliability index* ASAI (%)
Proposed method	13	34.53	99.9883
Traditional method [3]	10	33.14	99.9876

Table 4. The FRTUs deployment locations in different methods.

	Proposed method		Traditional method [3]	
	FRTUs	Switches controlled by deployment FRTUs	FRTUs	Switches controlled by deployment FRTUs
F1	3, 4, 5, 6, 7, 8	3E, 4E, 5E, 6E, 7E, 8E, 9B, 10B	1, 4, 5, 7,	2B, 3B, 4E, 5E, 7E, 8B, 9B, 10B,
F2	16, 17,18, 21	16E, 17E,18E, 20B, 23B	15, 18, 21	15E, 16B, 18E, 20B, 21E, 23B,
F3	27	28B	26,	26E, 27B,
F4	31	31E, 32B, 33B	31	32B, 33B
F5	40	41B	40	41B
F6	–	–	–	–

In Table 4, the FRTU deployment locations with different methods are compared. Seven FRTUs, labeled as 4, 5, 7, 18, 21, 31, and 40, are deployed in the same positions in both the proposed and the traditional methods. Other FRTUs are installed in different positions. For example, FRTUs are installed on the positions labeled as 3, 4, 5, 6, 7, and 8 along feeder F1 in the proposed method. However, FRTUs are installed on the positions labeled as 1, 4, 5, and 7 along feeder F1 in the traditional method. It can be seen that disregarding the customer's service restoration paths results in completely different deployment schemes and revenues. The benefit is the difference between the reduction in interruption cost and the cost of deploying FRTUs. The analysis shows that the proposed method can get significantly different numbers and deployment locations of FRTUs from those obtained by the traditional method, leading to higher revenue and reliability index, almost a difference of k$ 1.39 and 0.0007%, respectively. This is because FRTU does not contribute to the acceleration of the fault management process in different analysis methods. In simple terms, if a simplified analysis is performed, the FRTU-controlled RCS, located both on the path between the customer and the fault position and on the path between the customer and the power supply, can be used to isolate the fault and make the customer does not need to experience the fault location process. However, this can cause the switch used for isolation to cut off the restoration path. Hence, the choice of switches for isolation has to be limited, leading to some differences in the final optimization results.

4. Conclusion

To improve the reliability of power supply in the distribution network and reduce the cost of customer interruption caused by faults, a new method to deploy feeder remote terminal units (FRTUs) in distribution networks is proposed.

Unlike the existing deployment methods, this paper finely analyzes the impact of fault isolation on the service restoration process in the fault management procedure in which FRTUs participate. Based on this, a mathematical deployment model dedicated to minimizing the sum of equipment cost of FRTUs and fault interruption cost is developed. This model in mixed-integer nonlinear format can be solved efficiently with LocalSolver, which combines sophisticated techniques such as heuristic algorithms and nonlinear programming.

The simulation results on the CSG 53-node test system show that the deployment of FRTUs reduces the total cost by k$ 34.53, or about 30%. Furthermore, the average annual interruption time for all system customers can be reduced by almost 40.73 h. The results of the sensitivity analysis, in terms of fault rate, customer damage function, and average fault location time, demonstrate the validity of the proposed model and method. In addition, the results show that the coupling relationship between the fault isolation process and the restoration process results in a different deployment scheme and higher revenue, about k$ 1.39 more than the traditional method.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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