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Modified centralized ROCOF based load shedding scheme in an islanded distribution network

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ABSTRACT

This paper presents two centralized adaptive under frequency load shedding (UFLS) methods based on loads willing to pay (WTP) and new objective function. The objective function is considered to minimize load shedding penalties that are paid by distribution network operator (DNO), using optimal algorithm. Maintaining DG units in an islanded distribution system is proposed to prevent system blackout. One of the most important protection schemes to prevent a system blackout is UFLS method. In our proposed UFLS method, amount of load shedding is dependent on loads priority table and intensity of event. Loads priority table is formed, using rate of change of frequency of loads (ROCOFL) indices. Proposed techniques apply the amount of loads active power every few minutes to update loads priority table. These proposed UFLS methods are implemented on the 14-bus Danish distribution system in 3 different load scenarios and are compared with a conventional approach.

Introduction

Motivation

Sudden increase of the system demand or electric supply failures may cause imbalance between generation and demand. This way, eventually, lead to frequency instability and blackout. When there is a small difference between power system consumption and generation, governors can retrieve the balance by controlling output power. Spinning reserves are the extra generation capacity of the connected generators to the network. Spinning reserves can also adjust the imbalance by producing power [1].

In the case of abrupt reduction in the frequency, governor and spinning reserve responses are not fast enough to restore system to the normal operation. In order to return the system back to the normal state, UFLS schemes are put into the action. The available UFLS algorithms can be divided into the following categories [2]:

(1) Traditional.
(2) Semi adaptive.
(3) Adaptive.

This paper deals with the last category, i.e., adaptive UFLS algorithms. In a group of adaptive algorithms, rate of change of frequency (ROCOF) is applied as a criterion to estimate the intensity of disturbance. This scheme activates when the system frequency reaches a certain threshold. Based on the value of ROCOF, a certain amount of load is shed when the frequency falls below a threshold [2–4].

Review of related works

An adaptive UFLS scheme using system frequency response (SFR) model is presented in [5]. Using reduced order of SFR model provides a relation between the initial ROCOF and the size of disturbance.

According to [5], it is not necessary to shed an amount of load exactly equal to the size of disturbance. Considering the dependence of loads on the frequency, the system may tolerate a specific amount of imbalance, even without load shedding. Spinning reserves also help in this situation. Under frequency load shedding in presence of spinning reserves is completely described in [6].

Dependence of loads on the voltage is not considered in the SFR model. This is the major drawback of this model [7]. Some papers explore new methods to calculate the imbalance between generation and consumption in which loads voltage dependence is considered [8–10]. In order to improve the voltage stability margins, prioritizing the loads to be shed is considered with new methods presented in [7].

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Nomenclature

i,j	the existing bus in the network
J	the loads connected to the ith bus
f	frequency
f_{COI}	frequency of the center of inertia (COI)
H_{COI}	network central inertia constant
H_{Gen}^{k}	kth generator inertia constant
$m_{0critical}$	initial critical frequency variation
ROCOFL_p^*	updated ROCOFL index considering active power variation.
$P_{new}(i,J)$	updated active power value of the Jth load in ith bus
$P_{old}(i,J)$	active power of the Jth load in ith bus
P_0	loads nominal active power
Q_0	loads nominal reactive power
V_0	nominal voltage
f_0	nominal frequency
K_{pv}	dependence of active power on the voltage
K_{qv}	dependence of reactive power on the voltage
K_{pf}	dependence of active power on the frequency
K_{qf}	dependence of reactive power on the frequency
$\mathrm{ROCOFL}_{p,v}^*$	updated ROCOFL index considering loads active power and voltage
$c(i)$	marginal cost in the ith bus
$P_L(i,J)$	active power related to Jth load in ith bus
$U(J,i)$	binary variable which indicates Jth load in ith bus that should be shed
P_i^G	active power generated (or absorbed) in ith bus
Q_i^G	reactive power generated (or absorbed) in ith bus
P_i^{DG}	active power that DG units generated in ith bus
Q_i^{DG}	reactive power that DG units generated in ith bus
V_i	the magnitude of voltage in ith bus
δ_i	the angle of voltage in ith bus
P_i^D	load's active power
Q_i^D	load's reactive power
$V_i^{\max}$	the maximum limits of voltage magnitudes at ith bus
$V_i^{\min}$	the minimum limits of voltage magnitudes at ith bus
$P_{DG}^{\max}$	maximum active power of DG
$P_{DG}^{\min}$	minimum active power of DG
$P_{Grid}^{\max}$	maximum active power limits of substation
$P_{Grid}^{\min}$	minimum active power limits of substation
$S_{ij}^{\max}$	maximum thermal limit of branch between i and j
P_i^{Grid}	active power imported from grid
Q_i^{Grid}	reactive power imported from grid
S_{ij}	power flow in branch between i, j
$Cost(CHP)$	cost of CHP
P	CHP power output
H	CHP heat recovery output

The priority of loads to be shed can be obtained by measuring ROCOF in each bus [11]. The frequency of the center of inertia (f_{COI}) is calculated and compared with ROCOF of each bus. The bus that has greatest ROCOF, drops its loads first [11]. Using ROCOFL indices, it is possible to estimate size of imbalance without using SFR model [12]. DGs are expected to play an increasing role in emerging electric power systems. Large amount of DG units allow network to operate in an islanded mode as a micro-grid. The islanded operation of the distribution networks has been studied in [11,12]. It is obvious that the strategy for load shedding in distribution networks with DGs must be different from the conventional systems.

Application of centralised load shedding algorithms has been proposed in some research works [13–15]. Two centralised adaptive load shedding algorithms are proposed in [7]. The first algorithm is response-based and the second one is a combination of event-based and response-based methods. In centralized adaptive algorithms, measured amounts of required signals are transmitted to the control center and the appropriate decision to shed loads is made in this center. A reliable and fast communication link, which is currently available in most power systems, is vital in centralized adaptive methods. Communication systems provide a lot of helpful information for the load shedding process. Centralized UFLS methods can adaptively select frequency and intentional time delay settings as well as the amount and location of loads to be shed. Centralized UFLS scheme based on a frequency stability boundary curve defined within the $\omega - d\omega/dt$ (frequency versus ROCOF) phase plane is presented in [16].

To optimize the amount of load shedding in UFLS methods, optimal UFLS algorithms are proposed. These methods are categorized in deterministic and heuristic optimization algorithms.

In deterministic optimization algorithms, frequency thresholds, intentional delay times and step sizes are optimized. An optimization by means of quasi – newton methods is presented in [17]. In heuristic algorithms, all frequency thresholds and intentional delay times are fixed and step sizes are optimized, as considered in our proposed paper. In [18], an optimization by means of genetic algorithm (GA) is presented. Variation of UFLS step sizes and impact of non-responding turbine generator systems in UFLS methods are analyzed by Monte Carlo (MC) approach in [19].

Contributions

In this paper, two centralized adaptive UFLS schemes are proposed. The contribution of the proposed work in comparison with the previously published works like as [12] could be summarized as follows:

1. Loads are changing continuously and the effect of load variation on ROCOFL is not considered in [12]. In the proposed method, computations for determining updated ROCOFL indices are performed offline by active power amount sent to control center every few minutes. Information obtained in the control center is being processed and the loads to be shed are prioritized.
2. Voltage and frequency dependency of the loads will affect the ROCOFL index calculation in [12]. According to reduced SFR model, initial ROCOF is in a direct relation with the active power imbalance. In this paper, measured initial ROCOF should be multiplied by a factor of 1.05 to model loads voltage dependence in ROCOFL determination.
3. The frequency control module (FCM) is used to calculate f_{COI} in the proposed methods which is not considered in previous works.
4. Spinning reserves make small disturbances tolerable. In order to prevent overshedding, the initial critical frequency variation ($m_{0\ \mathrm{crtitical}}$) should be compared with the amount of measured initial ROCOF which is not considered previously. $m_{0\ \mathrm{crtitical}}$ shows the maximum variation of frequency that the network can tolerate without shedding any load.
5. Priority of loads to be shed is based on loads WTP in [12]. In the proposed methods, load shedding control module (LSCM) module is proposed which determines the loads to be shed. In the

second proposed method, LSCM module uses optimal solutions to provide minimum cost function (CF) and minimizes the payment of penalty by the DNO and imposed by the disconnection of loads which is not considered in the first proposed method and the conventional ones. In the proposed CF, ROCOFL constraint is used to retrieve the balance with an acceptable system frequency. In contrast to our work, no optimization is considered in [12].
6. ROCOF threshold value presented in [12] is corresponding to the lowest ROCOFL index. In our proposed method, M and $m_{0\text{critical}}$ are threshold values obtained through the study of various scenarios. These threshold values diagnose different types of events in the system.
7. Different event types are not considered in [12] that cause overshedding in small disturbances. Loads are shed according to measured initial ROCOF and ROCOF threshold value in this algorithm. Unshed loads will have to wait for the frequency to go down below frequency threshold and for the ROCOF to be negative for the duration of T. ROCOF values must be sent by frequency relays to the control center every half cycle after islanding detection in [12]. In the proposed methods, the intensity of event is divided into 3 types: severe, moderate and weak. In the proposed adaptive methods, frequency threshold values, intentional delay times and step sizes are changed based on the measured initial ROCOF value. In this proposed method, we just use initial ROCOF value after islanding detection.

Paper organization

The remainder of the paper is organized as follows. Proposed algorithm is explained in Section 'The proposed methods'. In Section 'Assumptions and test system', assumptions and test system are explained. In Section 'Simulation results and discussions', the methodology is implemented in DigSilent Power Factory 14.0.520 on the 14-bus Danish distribution system in three different load scenarios. Conclusions are finally given in Section 'Conclusion'.

The proposed methods

In the proposed methods, in order to prevent network instability, frequency relays continuously send the values of local frequency to the control center to perform required actions and select loads to be shed. By removing these loads, network can retrieve the balance of generation and consumption following a disturbance. Hence, an islanded network may continue its normal operation as a micro-grid.

System frequency

The frequency of the center of inertia is used in ROCOF calculation, [11]. Therefore, system initial ROCOF can be obtained as the following:

$$(df/dt)_{COI_0} = \frac{\left(\sum_{k=1}^{n} (df/dt)_{t=0}^{k} \times H_{Gen}^{k}\right)}{H_{COI}} \quad (1)$$

where $(df/dt)_{t=0}^{k}$ shows the initial ROCOF of the kth generator. H_{COI} and H_{Gen}^{k} show network central inertia constant and kth generator inertia constant, respectively.

Considering spinning reserves, in order to prevent over shedding, we should compare amount of measured initial ROCOF with initial critical frequency variation ($m_{0critical}$). $m_{0critical}$ shows the maximum variation of frequency that the network can tolerate without shedding any loads. This should be obtained, specifically, for each system, through extensive simulation studies.

Using Eq. (2), modified initial ROCOF is presented as follows:

$$(df/dt)_{COI_0}^{*} = (df/dt)_{COI_0} - m_{0critical} \quad (2)$$

ROCOFL determination

In this paper, ROCOFL index has been determined for each load. In [12], the following procedures are applied to determine ROCOFL indices. First, it is assumed that the network continues to work in an islanded mode and there is no imbalance in the network. Deliberately, the amount of load in each bus separately is duplicated. In this case, an imbalance with size of each load has occurred in the network. Then the initial ROCOF is measured and ROCOFL indices for each load are obtained. In determination of ROCOFL indices, loads are assumed to be constant. It should be mentioned that all of the computations are performed offline.

In ROCOFL index determination presented in [12], the following problems are encountered:

(1) Loads active powers are not accurately predictable and change continuously. This has not been considered in [12].
(2) Loads voltage and frequency dependence cause errors in the calculation of ROCOFL indices.

- Solution to the first problem

Using reduced SFR model, ROCOF has a linear relation to the active power imbalance. Therefore, the first problem can be solved by updating indices values every few minutes using Eq. (3). Loads active powers are transmitted to the control center every few minutes. This procedure does not require high speed communication links [7].

$$\text{ROCOFL}_p^{*} = \text{ROCOFL} \times \left(\frac{P_{new}(i,J)}{P_{old}(i,J)}\right) \quad (3)$$

where ROCOFL_p^{*} shows the updated ROCOFL index based on loads active power. $P_{new}(i,J)$ is the updated active power value of the Jth load in the ith bus transmitted to the control center. $P_{old}(i,J)$ shows the active power of Jth load in the ith bus that the preliminary ROCOFL indices calculations were based on it. According to (3), ROCOFL index for each load has linear relation with the active power of the load.

- Solution to the second problem

Loads used in the network are frequency and voltage dependent. These dependencies may be modeled by Eqs. (4) and (5) [20]:

$$P = P_0\left(\frac{V}{V_0}\right)^{K_{pv}}\left(1 + K_{pf} \times \frac{\Delta f}{f_0}\right) \quad (4)$$

$$Q = Q_0\left(\frac{V}{V_0}\right)^{K_{qv}}\left(1 + K_{qf} \times \frac{\Delta f}{f_0}\right) \quad (5)$$

P_0 and Q_0 are the loads nominal active and reactive powers. In addition, V_0 and f_0 are nominal voltage and frequency, respectively.

Active and reactive powers change due to voltage and frequency variation. K_{pv} and K_{qv} show the dependence of active and reactive powers to the voltage, respectively. Also, K_{pf} and K_{qf} represent dependence of active and reactive powers to the frequency, respectively.

Estimated active power imbalance is multiplied by a factor of 1.05 to model loads voltage dependence, in SFR model [7]. In this paper, calculated initial ROCOF should be multiplied by a factor of 1.05 to solve the second problem. Using Eq. (2), modified initial ROCOF which considers loads voltage dependence can be obtained as follows:

$$(df/dt)_{COI_0}^{*} = 1.05 * (df/dt)_{COI_0} - m_{0critical} \quad (6)$$

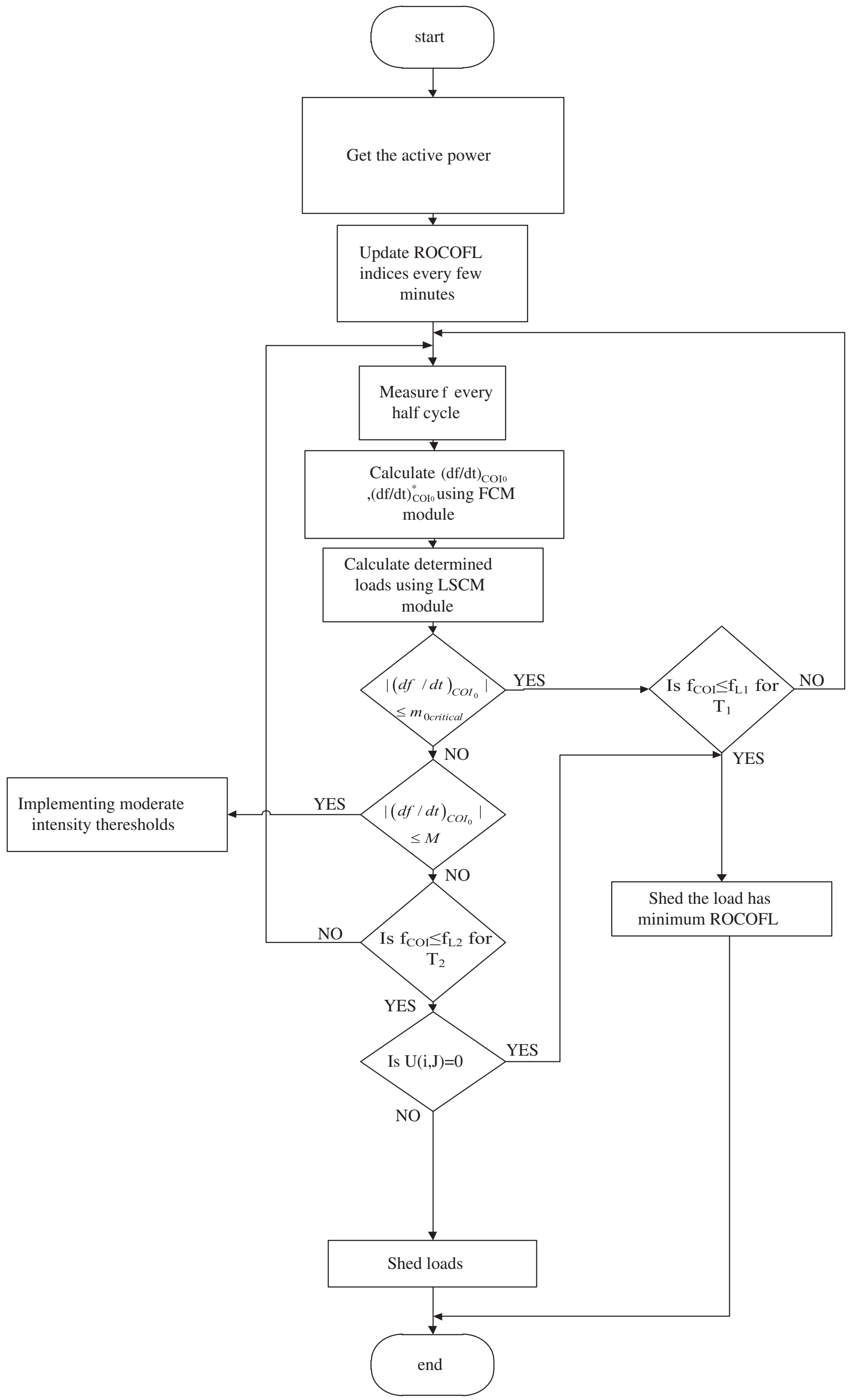

Fig. 1. Flowchart of the proposed method.

Proposed UFLS flowchart

Both proposed centralized algorithms use the UFLS flow-chart presented in Fig. 1. Since the amounts of loads active power are sent to the control center every few minutes, the ROCOFL indices are updated. Initially, islanded operation of distribution network is detected by islanding detection methods like the one proposed in [21].

Frequency (*f*) and frequency variation (*df/dt*) of each generator are measured by installed frequency relays. $(df/dt)_{COI_0}$ and $(df/dt)^*_{COI_0}$ are calculated by Eqs. (1) and (3) using FCM in the control center and the LSCM provides determined loads to be shed which are not presented in [12]. Determined loads are shed by considering proposed method.

In the proposed method, M and $m_{0critical}$ are ROCOF threshold values obtained through the study of various scenarios. These

Table 1
Proposed adaptive UFLS scheme.

Event type	System initial ROCOF	Frequency state and time delay	Amount of load to be shed
Low	$\lvert(df/dt)_{COI_0}\rvert \leqslant m_{0critical}$	$f_{COI} < fL_1$ for T_1	The load has minimum ROCOFL index
Moderate	$m_{0critical} \leqslant \lvert(df/dt)_{COI_0}\rvert \leqslant M$	Step 1: $f_{COI} < fth_1$ for y_1 Step 2: $f_{COI} < fth_2$ for y_2 Step 3: $f_{COI} < fth_3$	Step 1: ×1% of determined loads Step 2: ×2% of determined loads Step 3: rest of determined load
Severe	$\lvert(df/dt)_{COI_0}\rvert \geqslant M$	$f_{COI} < fL_2$ for T_2	All of the determined loads

threshold values diagnose different types of events in the system. Also we determine M for the case that 30% of generation is lost [22]. Time delays (y_1, y_2, T_1, T_2) and frequency thresholds (f_{th1}, f_{th2}, f_{th3}, f_{L1}, f_{L2}) for each step are achieved by studying various scenarios. In addition, T_3 is imposed delay time caused by breakers operation and communication delay time.

Depending on the calculated $(df/dt)_{COI_0}$, intensity of event is classified in three states: low, moderate, and severe. For a small event, $(df/dt)_{COI_0}$ is less than $m_{0critical}$. If f_{COI} is less than f_{L1} for more than T_1 seconds, to prevent frequency instability, load with the lowest ROCOFL index will be removed. If $(df/dt)_{COI_0}$ is less than M and greater than $m_{0critical}$, the algorithm will recognize event as the moderate one and the proposed load shedding procedure is implemented. When $(df/dt)_{COI_0}$ is greater than M, the intensity of event is severe and all the determined loads must be shed.

When all the above constraints are imposed and determined loads equals to zero, to prevent frequency instability, the load with minimum ROCOFL is selected.

In Table 1, the action of the proposed adaptive UFLS algorithm is summarized.

According to Table 1, in moderate events, amounts of shedding loads in each step ($x1$, $x2$) are assigned. When system frequency reaches specified frequency thresholds, loads are shed in each step. Using the proposed algorithm, UFLS scheme can operate and retrieve the balance of generation and consumption.

Load shedding controller module (LSCM)

For both adaptive methods, LSCM can determine loads to be shed. Determined loads are shed according to the type of event.

- LSCM operation for the first proposed adaptive method

Load shedding in distribution systems must not be governed by technical reasons alone. Economic reasons play an important role in the islanded distribution systems. Some of the customers will pay more for the better power reliability. DNOs are obligated to supply loads that are paying more without regarding to demand size. In this adaptive method, loads priority table is based on loads WTP.

- LSCM operation for the second proposed adaptive method

As it was mentioned in previous sections, number of the loads should be disconnected to provide normal operation to the islanded network. Due to load's interruption, the cost of intentional load curtail (ILC) at each bus is considered to be 100 times of the ith bus marginal cost ($c(i)$). Hence, the optimal number of loads based on ROCOFL indices is determined so that the payment penalty is minimized and the network will return to the normal operating condition.

The cost function (CF) is defined as follows:

$$CF = \sum_{i=1}^{n}\sum_{J=1}^{m} 100 \times c(i) P_{shed}(i,J) \tag{7}$$

$$P_{shed}(i,J) = P_L(i,J) \times U(i,J) \tag{8}$$

where i represents the existent bus in the network and J shows the loads connected to the ith bus. $P_L(i,J)$ is active power related to Jth load in the ith bus. $U(i,J)$ is a binary variable which indicates Jth load in the ith bus that should be shed.

The power flow equations must be satisfied in the ith bus as follows:

$$P_i^{Grid} + P_i^{DG} - P_i^{D} = V_i \sum_{j}^{n} V_j (G_{ij}\cos\delta_i + B_{ij}\sin\delta_i) \tag{9}$$

$$Q_i^{Grid} + Q_i^{DG} - Q_i^{D} = V_i \sum_{j}^{n} V_j (G_{ij}\cos\delta_i + B_{ij}\sin\delta_i) \tag{10}$$

where P_i^{Grid} and Q_i^{Grid} are active and reactive power generated (or absorbed) in the ith substation. V_i and δ_i show the magnitude and angle of voltage in the ith bus, respectively.

P_i^{DG} and Q_i^{DG} are active and reactive power that DG units generated in the ith substation. P_i^{D} and Q_i^{D} are load's active and reactive power.

The voltage of each bus and its angle should be kept in the safe operating limits.

$$V_i^{\min} \leqslant V_i \leqslant V_i^{\max} \tag{11}$$

$$\delta_i^{\min} \leqslant \delta_i \leqslant \delta_i^{\max} \tag{12}$$

where $V_i^{\max}$ and $V_i^{\min}$ are the maximum and minimum limits of voltage magnitudes at the ith bus, respectively.

The active and reactive power limits of the substation are proportional to its capacity and can be formulated as follows [23]:

$$P_{Grid}^{\min} \leqslant P_i^{Grid} \leqslant P_{Grid}^{\max} \tag{13}$$

$$Q_{Grid}^{\min} \leqslant Q_i^{Grid} \leqslant Q_{Grid}^{\max} \tag{14}$$

The DG units should be operated with considering the limits of their maximum installed capacity [23]:

$$P_{DG}^{\min} \leqslant P_i^{DG} \leqslant P_{DG}^{\max} \tag{15}$$

$$Q_{DG}^{\min} \leqslant Q_i^{DG} \leqslant Q_{DG}^{\max} \tag{16}$$

The thermal constraint of the line connected between nodes i and j should be satisfied as follows:

$$S_{ij} \leqslant S_{ij}^{\max} \tag{17}$$

In this paper, ROCOFL constraint is proposed as follows:

$$\sum_{i=1}^{n}\sum_{J=1}^{m} \mathrm{ROCOFL}_p^{*}(i,J) \times U(i,J) > (df/dt)_{COI_0}^{*} \tag{18}$$

Using Eq. (18), the total ROCOFL indices for the loads must be greater than modified initial ROCOF.

According to the assumed cost function and related constraints, marginal cost in each bus is obtained. According to the previous materials, LSCM is presented in Fig. 2.

Computation of LSCM in the second adaptive method is formulated as a mixed integer non-linear problem (MINLP) which can be solved using efficient commercial optimization packages like as GAMS.

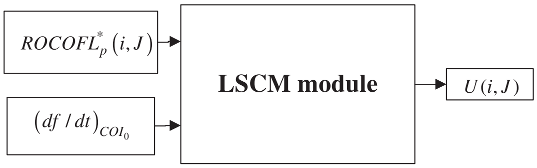

Fig. 2. LSCM in the proposed algorithms.

Table 3
Network and generator parameters.

Parameters	Values
H_{wind} (s)	0.38
S_{wind} (KVA)	692
H_{CHP} (s)	0.54
S_{CHP} (MVA)	4.125

Assumptions and test system

Assumptions of the problem

Static load models are used in the simulation studies. Loads are assumed to be voltage and frequency dependent. They are modeled using (2) and (3). The following parameters are used for load modeling [20].

$k_{pv} = 1, k_{qv} = 2, k_{pf} = 1, k_{qf} = -1$

Frequency thresholds of $f_{th1}, f_{th2}, f_{th3}, f_{L1}, f_{L2}$ are 49, 48.5, 48, 49 and 49.5 Hz, respectively for this case. Deliberate delay times of y_1, y_2, T_1, T_2 are 100, 200, 120, and 60 ms, respectively. The imposed delay time (T_3) caused by breakers operation and transmission delay is considered 80 ms [12].

In this paper, for moderate intensity, percent of load shedding in each step is as follows.

(1) step 1: 33% ($x1$),
(2) Step 2: 33% ($x2$),
(3) step 3: rest of the loads ($x3$).

The CHP cost function is considered as follows:

$$\text{Cost(CHP)} = aP^2 + bP + c + e'PH + f'H^2 \quad (19)$$

where P and H are CHP power and heat output. We assume that transmission grid works like a generator (G_{TranGrid}). Generator's cost function is considered as the same as CHP's. The cost function parameters for CHP and generator are listed in Table 2.

CHP output heat recovery is assumed constant and its value in 14-bus Danish distribution system is 32.85 MWth [24]. Operation cost of wind turbine generators are assumed zero. Other parameters used in this paper are listed in Table 3.

Description of 14-bus Danish distribution system

In this part, the proposed algorithm is tested on the Danish 14-bus network [12]. All the simulation studies are performed using DigSilent Power Factory 14.0.520 software. Fig. 3 shows the single diagram of Danish distribution network. The test system consists of three fixed-speed stall-regulated wind turbine generators (WTGs) of 630 kW which are installed on buses 8, 9, 10. A Combined Heat and Power (CHP) plant with three gas turbine generators of 3 MW are installed on bus 1. The CHP unit model is like as a gas turbine with heat recovery. The model used for CHP unit, presented in Ref. [24]. Network data and generator parameters are given in [12]. The distribution network is connected to the transmission network at bus 2.

Table 2
Generator and CHP cost function parameters.

Unit	14-bus Danish	
	$G_{\text{Tran Grid}}$	CHP
a	0.001	0.486
b	120	105
c	1500	350
e′	0	0.17
f′	0	0.11

A distribution system will continue to operate as an islanded network in effect of upstream outage. An IEEE-type ST1 excitation system and GAST model are used to model exciter and governor in proposed CHP plant, respectively. Those parameters of exciter and governor are given in appendix. Power demand over the two months of December 2006 and January 2007 are given in appendix.

Simulation results and discussions

The proposed method is applied to the distribution system to demonstrate its abilities. As already mentioned, the case study is the 14-bus Danish distribution system.

The proposed algorithm requires the calculation of ROCOFL index for each of the loads. ROCOFL index values are dependent on the network load and inertia. Calculation of the applied indices can be performed offline. For modeling the effect of load variation, the calculated ROCOFL indices are updated using (1). Since wind generators are not always presented in the network, ROCOFL calculations for the worst state will be considered (without taking into account wind generators [12]). ROCOFL values obtained for loads in December 2006 and updated values for January 2007 are presented in Table 4.

In this part, three load scenarios are considered as described in the following.

First load scenario: Using January 2007 active power demands.

Second load scenario: Loads STSY, STCE, STNO, 11, 10, 9 and 8 in January 2007 are increased by 10.

Third load scenario: All of the January 2007 active power demands are increased by 10 percent.

In this algorithm, optimal UFLS scheme is implemented by considering marginal costs of each bus. Marginal costs of each bus are obtained by running energy market based on defined cost function and network constraints for each scenarios.

Marginal cost values for each bus are listed in Table 5.

Using Eq. (3), ROCOFL_p^* values are obtained and listed in Table 6 for three scenarios using loads WTP.

Generators output powers are obtained by running an Optimal Power Flow (OPF) solution for different scenarios listed in Table 7.

In the first scenario, 14-bus test system with three CHP units and three wind generators are considered.

Distribution system is disconnected from the upstream network at time $t = 2$ s (s). Fig. 4 shows the system frequency during islanding without load shedding in different scenarios.

It is obvious that system frequency is unstable. The frequency cannot reach the acceptable range of frequency after 10 s. If UFLS method is not implemented and loads are not being shed, generators under frequency relays will trip and system is going to be collapsed.

In the first scenario, the network imbalance is 2.91 MW. CHP frequency at time $t = 2.01$(s) drops to 49.491 Hz and the CHP initial ROCOF is measured 5.9 Hz/s. In an islanded operation, CHP will increase its output power using its governor. Fig. 5 shows the CHP generation power in the first scenario.

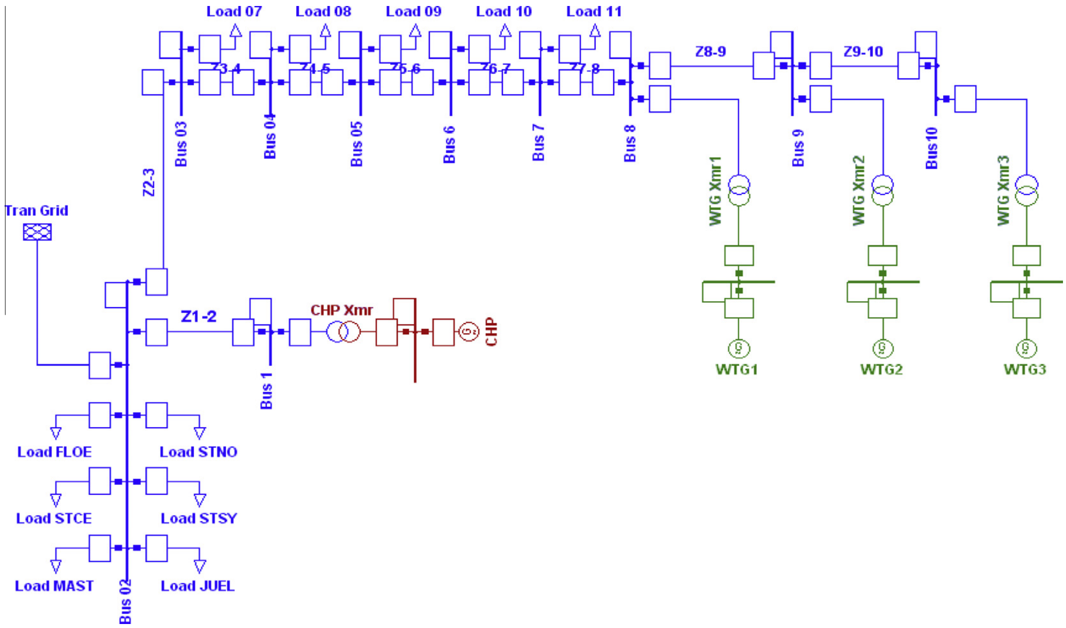

Fig. 3. Single line diagram of 14-bus Danish distribution system.

Table 4
Updated ROCOFL$_p^*$ values for January 2007 in the first scenario for 14-bus system.

Load	ROCOFL (HZ/s) December 2006	ROCOFL$_p^*$ (HZ/s) January 2007
8	−3.5	−3.25
JUEL	−4	−4
9	−0.55	−0.5
10	−0.55	−0.5
11	−0.55	−0.5
7	−2.2	−2.05
STCE	−5.15	−5.25
FLQE	−8.5	−9.55
STSY	−8.55	−7.45
STNO	−7.7	−9
MAST	−11.5	−12.5

Table 5
Marginal cost values in different scenarios.

BUS	Marginal cost ($C(i)$) ($/MW)		
	First load scenario	Second load scenario	Third load scenario
1	119.336	119.337	119.338
2	120.006	120.007	120.008
3	120.111	120.121	120.126
4	120.207	120.229	120.235
5	120.235	120.268	120.237
6	120.234	120.268	120.274
7	120.113	120.156	120.163
8	120.012	120.056	120.062
9	120.005	120.048	120.055
10	119.967	120.011	120.017

Using the results of performed simulation, an initial ROCOF of each generator is obtained as following:

$$\frac{df}{dt_{wind}}(t = 2.01s) = -7.8HZ/s \tag{20}$$

$$\frac{df}{dt_{CHP}}(t = 2.01s) = -5.9HZ/s \tag{21}$$

According to Eqs. (1), (2), $(df/dt)_{COI_0}$ and $(df/dt)^*_{COI_0}$ equal to 6.65 Hz/s and 6.15 Hz/s, respectively for the first scenario. According to amount of $(df/dt)_{COI_0}$, intensity of event in this scenario recognize moderate. Table 8 presents initial ROCOF and modified ROCOF for diffrent scenarios.

$P_L(i,J)$ used in cost function for 14-bus Danish test system in the second proposed method is as below:

$$P_L(i,J) = \begin{array}{c} \\ i2 \\ i3 \\ i4 \\ i5 \\ i6 \\ i7 \end{array}\!\!\begin{array}{c} \begin{array}{cccccc} J1 & J2 & J3 & J4 & J5 & J6 \end{array} \\ \begin{bmatrix} P_{FLQE} & P_{STCE} & P_{MAST} & P_{STNO} & P_{STSY} & P_{JUEL} \\ P_7 & - & - & - & - & - \\ P_8 & - & - & - & - & - \\ P_9 & - & - & - & - & - \\ P_{10} & - & - & - & - & - \\ P_{11} & - & - & - & - & - \end{bmatrix} \end{array}$$

Using LSCM module provides determined loads to be shed for both proposed adaptive methods as follows:

In the first adaptive method, determined loads and amount of load shedding is obtained using Table 9 in each scenario as follows:

In the second adaptive method, determined loads imposed minimum cost function in the first scenario is selected as follow:

$$U(J,i) = \begin{array}{c} \\ J1 \\ J2 \\ J3 \\ J4 \\ J5 \\ J6 \end{array}\!\!\begin{array}{c} \begin{array}{cccccc} i2 & i3 & i4 & i5 & i6 & i7 \end{array} \\ \begin{bmatrix} 0 & 1 & 1 & 1 & 1 & 1 \\ 0 & - & - & - & - & - \\ 0 & - & - & - & - & - \\ 0 & - & - & - & - & - \\ 0 & - & - & - & - & - \\ 0 & - & - & - & - & - \end{bmatrix} \end{array}$$

$U(J, i)$ shows determined loads which are Load 7, Load 8, Load 9, Load 10, and Load 11. Determined loads obtained by LSCM module and amount of cost function for different scenarios are shown in Table 10.

By considering proposed flowchart, it does not need to shed all of determined loads. Depending on type of scenario, shedding loads are going to be changed. Proposed UFLS method that applies to different scenarios is shown in Table 11.

Table 6
Updated ROCOFL$_p^*$ values for January 2007.

Load	WTP	First scenario		Second scenario		Third scenario	
		ROCOFL	ROCOFL$_p^*$	ROCOFL	ROCOFL$_p^*$	ROCOFL	ROCOFL$_p^*$
STSY	0.79	−7.45	−7.45	−7.45	−8.195	−7.45	−8.195
10	0.84	−0.5	−0.5	−0.5	−0.55	−0.5	−0.55
STNO	0.85	−9	−9	−9	−9.9	−9	−9.9
9	0.86	−0.5	−0.5	−0.5	−0.55	−0.5	−0.55
STCE	0.89	−5.25	−5.25	−5.25	−5.775	−5.25	−5.775
7	0.9	−2.05	−2.05	−2.05	−2.05	−2.05	−2.225
8	0.91	−3.25	−3.25	−3.25	−3.57	−3.25	−3.57
FLQE	0.95	−9.55	−9.55	−9.55	−9.55	−9.55	−10.51
11	0.98	−0.5	−0.5	−0.5	−0.55	−0.5	−0.55
JUEL	0.99	−4	−4	−4	−4	−4	−4.4
MAST	1	−12.5	−12.5	−12.5	−12.5	−12.5	−13.75

Table 7
Generators output power in different scenarios.

Generator	First scenario	Second scenario	Third scenario
$P_{GTranGrid}$ (MW)	2.91	3.498	4.118
P_{CHP} (MW)	9	9	9
P_{WTG1} (MW)	0.084	0.084	0.084
P_{WTG2} (MW)	0.084	0.084	0.084
P_{WTG3} (MW)	0.084	0.084	0.084
$Q_{GTranGrid}$ (MVar)	3.73	4.09	4.26
Q_{CHP} (MVar)	−0.637	−0.637	−0.637
Q_{WTG1} (MVar)	0	0	0
Q_{WTG2} (MVar)	0	0	0
Q_{WTG3} (MVar)	0	0	0

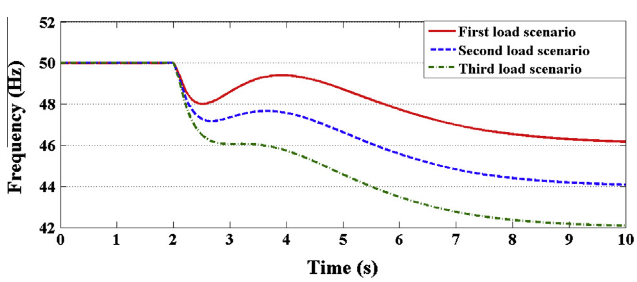

Fig. 4. System frequency without under frequency load shedding in different scenarios.

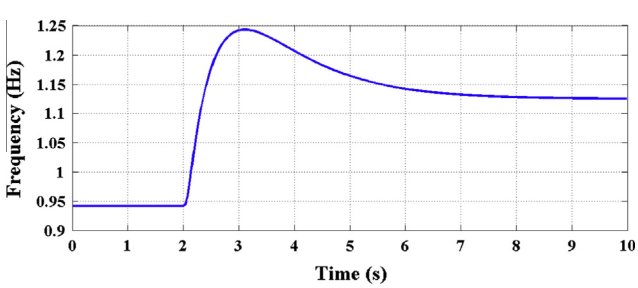

Fig. 5. CHP output power without under frequency load shedding in the first scenario.

Table 8
Event type in different scenarios.

Scenario	$(df/dt)_{COI_0}$ (Hz/s)	$(df/dt)^*_{COI_0}$ (Hz/s)	Type of event
1	6.65	6.48	Moderate
2	8.6	8.53	Moderate
3	10.54	10.57	Severe

Table 9
Determined loads and amount of load shedding in the first adaptive method for different load scenarios.

Scenario	Imbalance (MW)	Determined loads	Amount of determined loads (MW)	Amount of load shedding (MW)
1	2.91	STSY	1.656	1.656
2	3.5	STSY, 10	1.9481	1.9481
3	4.12	STSY, 10, STNO	4.1283	4.1283

Table 10
Determined loads and CF in the second adaptive method for different load scenarios.

Scenario	Determined loads	CF ($)
1	Load STCE, Load 9, Load 10, Load 11	18211.396
2	Load JUEL, Load 8, Load 9, Load 11	23420.638
3	Load STCE, Load 8, Load 9, Load 10, Load 11	27796.94

Table 11
Second adaptive UFLS method in different scenarios in 14-bus system.

Scenario	Imbalance (MW)	Determined loads	Amount of determined loads (MW)	Amount of load shedding (MW)
1	2.91	STCE, 9, 10, 11	1.517	1.402
2	3.5	JUEL, 8, 9, 11	1.9497	1.9497
3	4.12	STCE, 8, 9, 10,11	2.4654	2.4654

Using UFLS scheme presented in [12], dropped loads are obtained and presented in Table 12 for all different load scenarios.

CHP frequency after shedding specified loads for both proposed adaptive UFLS methods compared with UFLS algorithm presented in [12] in different load scenarios is presented in Figs. 6–8.

Amount of load shedding in our improved algorithm compared with the algorithm presented in [12] is shown in Table 13.

According to the results, in a small distribution network, we do not need to shed all of the determined loads for small disturbances. According to Table 11, in the first scenario, load 11 is not shed in our first proposed algorithm. The first algorithm provides fewer load shedding than the method presented in [12].

According to Table 13, it is obvious that the second proposed algorithm shed fewer loads than the algorithm presented in [12] and the first proposed algorithm. Also, second proposed algorithm

Table 12
Dropped loads using the algorithm presented in [12] for different load scenarios.

Scenario	Dropped loads	Amount of load shedding (MW)
1	STSY, 10	1.771
2	STSY, 10, STNO	4.1283
3	STSY, 10, STNO	4.1283

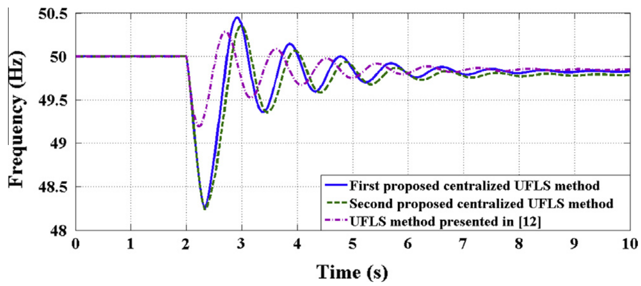

Fig. 6. System frequency after load shedding in the 1th load scenario in 14-bus test system.

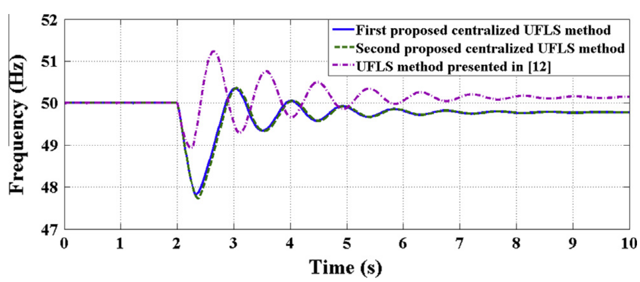

Fig. 7. System frequency after load shedding in the 2th load scenario in 14-bus test system.

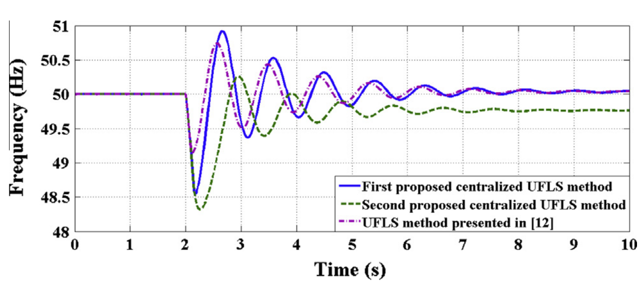

Fig. 8. System frequency after load shedding in the 3th load scenario in 14-bus test system.

Table 13
Amount of load shedding in both proposed and conventional ([12]) UFLS methods for different load scenarios.

Load scenario	Imbalance (MW)	Amount of load shedding using [12] (MW)	Amount of load shedding using first proposed UFLS algorithm (MW)	Amount of load shedding using second proposed UFLS algorithm (MW)
1	2.91	1.771	1.656	1.402
2	3.5	4.1283	1.94	1.94
3	4.12	4.1283	4.1283	2.4654

used optimal solutions to provide minimum CF which is not considered in the first adaptive method and the conventional method ([12]). Depending on the type of event, proposed algorithms change relay settings. For severe events proposed algorithms shed loads with minimum delay time compared to moderate event. According to Figs. 6–8, our proposed algorithms can retrieve the balance with an acceptable system frequency.

Conclusion

In this paper, two centralized adaptive UFLS methods that stabilize frequency of islanded network are presented. These algorithms are implemented in a system with competitive energy markets and economic issues are considered in the selection of amount and type of load. In our proposed method, ROCOFL indices are assigned to each load. ROCOFL indices can be updated every few minutes by receiving load's active power to the control center. Load's priority table is assigned based on WTP and minimizing system penalty paid by DNO in two different proposed methods. These centralized adaptive methods shed loads by measuring initial ROCOF. According to measured values, intensity of event is diagnosed. In this paper, we do not need to estimate P_{def} by reduced SFR model. In addition, this method provides ROCOF based scheme which considers loads voltage dependence and system critical frequency. The scheme has been tested on a 14-bus Danish distribution system in three different load scenarios. Using the proposed scheme, an islanded network can retrieve the balance by shedding proper loads.

Appendix A

(See Tables A1–A3).

Table A1
Excitation system data of CHP units.

Parameters	Value
Measurement delay (s)	0
Filter delay time (s)	0.01
Filter derivative time constant (s)	0
Controller gain (pu)	250
Controller time constant (s)	0.01
Exciter current compensation factor (pu)	0
Stabilization path gain (pu)	0.01
Stabilization path delay time (s)	1
Controller minimum input	−7.5
Controller minimum output	−7.5
Controller maximum input	9.35
Controller maximum output	9.35

Table A2
Governor system data of CHP units.

Parameters	Value
Speed droop (pu)	0.04
Controller time constant (s)	0.4
Actuator time constant (s)	0.04
Compressor time constant (s)	3
Ambient temperature load limit (pu)	0.9
Turbine factor (pu)	1
Frictional losses factor (pu)	0
Turbine rated power (MW)	0
Controller minimum output (pu)	0
Controller minimum output (pu)	1

Table A3
Load and generation data for the 14-bus Danish Distribution system [12].

Load	December 2006		January 2007	
	P (MW)	Q (MW)	P (MW)	Q (MW)
Load FLQE	1.888	0.453	2.109	0.576
Load JUEL	0.89	0.163	0.9	0.164
Load 07	0.4995	0.2054	0.4598	0.1341
Load 08	0.7868	0.3235	0.7243	0.2113
Load 09	0.1249	0.0514	0.115	0.0335
Load 10	0.1249	0.0514	0.115	0.0335
Load 11	0.1249	0.0514	0.115	0.0335
Load MAST	2.521	0.878	2.732	0.842
Load STCE	1.158	0.168	1.172	0.139
Load STNO	1.699	0.248	1.982	0.223
Load STS	1.901	0.493	1.656	0.384

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