A New Centralized Adaptive Under-Frequency Load Shedding Controller for Microgrids based on a Distribution State Estimator

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Abstract—This paper presents a new centralized adaptive under-frequency load shedding controller that is integrated with a distribution state estimator to improve the frequency stability of islanded microgrids. Whilst under-frequency load shedding is a well-established corrective emergency frequency control action, it is not entirely suitable for use in microgrids with low inertia and a limited number of measurement devices. The novel centralized controller presented in this paper overcomes these challenges by incorporating a distribution state estimator to estimate the power consumption of the demand. In parallel to this, the actual active power imbalance in the microgrid is estimated by simultaneously monitoring the system frequency and its rate of change. The centralized controller uses these two variables to determine the correct amount of load to be shed. The performance of the proposed controller has been validated using computer simulations of the actual distribution network in Malaysia. These simulation results show the effectiveness of the proposed centralized controller for preventing power system instabilities, which might lead to cascading outages and even a complete blackout in microgrids that have been disconnected/islanded, from the main grid.

Index Terms—Centralized under-frequency load shedding, distribution network, distributed resource, distribution state estimator, islanding operation, microgrid.

ACRONYMS AND ABBREVIATIONS

CAULSC Centralized Adaptive Under-frequency Load Shedding Controller
COI the equivalent Centre of Inertia
DR Distributed Resource
DSE Distribution State Estimator
DSEM Distribution State Estimator Module
DMS Distribution Management System
ECM Event Calculator Module
FCM Frequency Calculator Module
LSCM Load Shedding Controller Module
PCC Point of Common Coupling
PMU Phasor Measurement Unit
ROCOF Rate of Change of Frequency
UFLS Under-Frequency Load Shedding

I. INTRODUCTION

The islanded operation of a microgrid enables the continued supply of power to customers during any interruption of the supply from the main grid. This is achieved by using the available Distributed Resource (DR) in the distribution system to supply electrical power whenever the main grid is disconnected. With this approach in mind, in 2011 a guide for the design and operation of islanded systems with a high penetration of DR when integrated with the main electric power system (IEEE Standard 1547.4-2011) was approved [1]. However, even with such a guide, operating DRs in an islanded microgrid poses a number of issues, foremost of which is the risk of frequency instability. When a distribution network is islanded it will continue to experience fluctuations in load and generation but will not have the support of the rest of the system, leaving it much more vulnerable to frequency and voltage excursions. For DRs with low inertia, such as mini hydro, the system frequency will fall very quickly and the speed controllers (governors) of the DRs may not be able to maintain the stability of the microgrid. Therefore, the use of load shedding to stabilize the frequency of an islanded microgrid may be necessary.

The most common load shedding technique applied by power utilities is decentralized conventional under-frequency load shedding (UFLS), which disconnects certain predefined loads or feeders based on certain frequency threshold values and with a predefined delay. The main flaw of this predefined load shedding is that it lacks an estimate of the load power imbalance in the system, which means that the amount of load to be shed is based on an assumed system state and size of imbalance and not the actual system conditions. Therefore, in practice, the scheme will tend to either over shed or under shed, both of which can have undesirable consequences. Over shedding is a particular threat to the stability of low inertia systems because they will experience a larger initial Rate of Change of Frequency (ROCOF) after the shedding, which may cause the maloperation of loss of mains or other ROCOF based protection.
The problem of load power imbalance estimation has been widely investigated [1-4]. Hence, adaptive load shedding schemes have been introduced that improve upon conventional load shedding by only shedding the required amount of load, which is calculated in real time by assessing the actual rate of change of the system frequency (df/dt - ROCOF) [5, 6]. However, ROCOF can be difficult to measure accurately, especially when the measurement point is close to a disturbance, induction machines or dynamic loads. In [7], an interesting simulation-based study is presented to quantify the level of performance for traditional UFLS scheme in different operating conditions. Adaptive UFLS schemes can be further improved by using a centralized UFLS controller and power system automation and communication devices to shed the correct amount of load at the correct locations [6, 8, 9]. Various UFLS schemes that depend on modern communication devices have been investigated in the open literature [10-12]. In [13, 14] voltage dependent load modeling was incorporated to enhance the active power imbalance estimation. Other research has been conducted into the use of combinational load shedding methods that can address voltage stability issues as part of adaptive UFLS. In [15], an adaptive UFLS scheme that combines event-based and response-based methods is proposed for an islanded distribution system. However, its efficacy relies on a significant number of measurement devices, which makes the scheme uneconomical for practical application.

In practice, distribution systems have a limited number of measurement devices that are commonly located at the main substations, i.e. not at the load buses that must be monitored by the centralized controller. In order to address this limitation, a Distribution State Estimator (DSE) [16-20] can be used to determine the loading (active and reactive power) and voltage at those buses where measurements are not available. The reduced number of measurements available in DSE, when compared to a transmission state estimator, means that the use of pseudo measurements is commonplace. Pseudo measurements can be obtained using approximate methods such as load forecasting or historical data.

In this paper, a new Centralized Adaptive Under-frequency Load Shedding Controller (CAULSC) based on UFLS and DSE is proposed for microgrids with DRs. This extends on the work presented in [15] by using DSE to mitigate the dependence of the centralized controller on excessive investment in new measurement devices. The proposed CAULSC can significantly contribute to the frequency stability of islanded microgrids. This has been demonstrated through a number of different case studies of generator tripping, load increases and loss of the main grid connection for part of the distribution network in Malaysia.

II. LOAD FREQUENCY CONTROL IN POWER SYSTEMS

Load frequency control is responsible for ensuring the frequency stability of power systems. Because of the random nature of the demand, a power system is never in an entirely balanced state and the system frequency will decrease if there is an excess of load and increase if there is an excess of generation. Hence, the system frequency reflects the imbalance between generation and load and must be closely controlled within a specific range for the following reasons:

- The proper operation of many electrical motors and numerous customer applications depend on the frequency of supply being close to the nominal value.
- Modern electronic devices use the frequency of their supply as a foundation for timing various processes.
- The performance of many of the auxiliary services of a generator are frequency dependent and if they underperform the power station output may be reduced or generator tripping could occur.

In order to maintain a satisfactory frequency the speed of the generators must be precisely controlled, since they dictate the system’s frequency and inefficient control would increase the cost of operating the power system. When the shaft decelerates (accelerates) a proportional decrease (increase) in the frequency will occur. In a generator, the prime mover is generally equipped with a governor that monitors the shaft speed and decreases (increases) the torque applied to the shaft if the speed is below (above) the reference speed. The governor acts to limit the frequency deviation by providing primary control after a disturbance but does not act to return the frequency to its nominal value. To return the system frequency to the nominal value a secondary regulation is required; this involves the set point of the generator being changed to decrease (increase) the output power of the generator for a given speed.

Therefore, the size of the frequency deviation after a given disturbance depends on the amount of governor response and spinning reserve that is available in the system. If the deviation is allowed to become too large then the under/over frequency protection of the generators will be forced to disconnect them from the system to prevent them from being damaged. In the case of an over frequency this generator tripping constitutes negative feedback, as losing a generator will cause the frequency to fall. However, in the case of an under-frequency it will constitute positive feedback and the loss of each generator will only exacerbate the severity of the deviation. The tripping of generators should not be viewed as a desirable strategy for controlling over-frequencies, but the contrasting nature of the feedback in each scenario does mean that under-frequency conditions tend to be a greater threat to system stability. Under-frequency load shedding is an effective corrective measure for limiting frequency deviations below nominal frequency to an acceptable range and preventing generator tripping. Therefore, it is important to coordinate the under-frequency protection of generators with the under-frequency load shedding, i.e. the load shedding must operate prior to the generator under-frequency protection if system collapse is to be averted.

III. CENTRALIZED ADAPTIVE UNDER-FREQUENCY LOAD SHEDDING CONTROLLER (CAULSC) FOR MICROGRIDS

In this paper, a CAULSC is proposed based on UFLS and DSE to improve the frequency stability of microgrids with...
significant penetrations of DR when they are operated as isolated islands. The CAULSC is modular in nature and consists of the following four major modules:

(a) Event Calculator Module (ECM),
(b) Frequency Calculator Module (FCM),
(c) Distribution State Estimator Module (DSEM) and
(d) Load Shedding Controller Module (LSCM).

The proposed controller has two modes of operation: (a) Event based and (b) Response based. The event based mode is used to contain the frequency deviation after two types of event (i) when the microgrid is islanded from the grid, (ii) when one of the generators in the microgrid is disconnected and the microgrid has already been islanded. When operating in the event based mode the power imbalance is determined using power flow measurements from the Point of Common Coupling (PCC) (point of connection to the main grid) (i) or the generator that has been disconnected (ii). The response based mode allows the controller to react to sudden increases in load demand in an islanded microgrid. The response based mode determines the power imbalance based on the ROCOF measured after the disturbance and the microgrid inertia [21].

For both modes of operation the proposed controller separates the load shedding into four stages that are triggered by applying user defined thresholds to the frequency of the center of inertia \( f_i \). The thresholds used here are 49.5 Hz, 49.0 Hz, 48.5 Hz and 48.0 Hz. The first stage of the load shedding also has a second threshold that is applied to the ROCOF. Specifically, this first stage will be performed if the \( \Delta f \) is equal to the power imbalance created by the disturbance.\( \Delta f \) = \( P_{\text{shed}} \) / \( f \), and the system frequency \( f < 49.5 \) Hz.

The proposed controller uses several modules to monitor and control the microgrid. Fig. 2 shows the interconnection between these modules and Fig. 3 is a flowchart of the data collection required by the CAULSC.

To deliver this shedding action the CAULSC uses several modules: Measurement Unit, Distribution Management System (DMS), DSEM, FCM, LSCM, ECM. Fig. 1 shows the flowchart of the data collection required by the CAULSC.

The DSEM measures the ROCOF of the equivalent inertia center of the microgrid [4]. If the ROCOF is captured immediately after the disturbance, at \( t = 0^+ \) (s), it can be used to estimate the actual power imbalance based on the swing equation in the LSCM. This allows the LSCM to determine the necessary level of shedding for a response based action when the ECM indicates that shedding is necessary.

It is envisaged that the proposed controller will be a part of the future/existing Distribution Management System (DMS). This should allow continuous monitoring of the distribution system and permanent assessment of the state of the system.

Fig. 1. Flowchart of the CAULSC for microgrids.

Fig. 2. Overall concept of the proposed CAULSC.
Measure the frequency of the COI

Measure the frequency of the grid

Send COI frequency to the LSCM

A. Event Calculator Module (ECM)

The ECM monitors the real-time measurements produced by Phasor Measurement Units (PMUs) installed at the main substations of the microgrid. It also monitors the status of the remote circuit breakers. In Fig. 4, a flowchart for the ECM is shown. The ECM detects the islanded operation of the microgrid by monitoring the grid circuit breaker. Once the ECM detects that the microgrid has become islanded the active power supplied by the grid prior to the islanding event is captured as the power imbalance.

B. Frequency Calculator Module (FCM)

The FCM calculates the frequency of the microgrid based on synchronized measurements and Fig. 5 presents a flow chart of its operation. This frequency is used by the LSCM to determine if the frequency thresholds of each shedding stage have been violated and to determine the necessary level of shedding when the CAULSC must deliver a response based shedding action.

The frequency calculated by the FCM is the frequency of the equivalent Centre of Inertia (COI) of the microgrid [4, 5, 13, 22]. This COI frequency can be calculated using multiple frequency measurements from the microgrid and the expression below:

$$f_c = \frac{\sum_{i=1}^{N} H_i \times f_i}{\sum_{i=1}^{N} H_i}$$

where, for N measurements, the $i^{th}$ measurement, $f_i$ is the frequency and $H_i$ is the inertia.

A flowchart for the FCM is shown in Fig. 5. The FCM relies on the assessment of the frequency of the equivalent inertia center, which is an effective measure of the system frequency when the individual generators are experiencing local or inter-area oscillations. It can be seen in Fig. 5 that the FCM continuously monitors the frequency, even when the CAULSC is not armed (i.e. the microgrid is not disconnected), this allows the frequency to be immediately available to the LSCM when an event does occur. Furthermore, to calculate the COI frequency the FCM requires inertia values/weights for each frequency measurement (e.g. the inertia of the generator where the frequency measurement was made).

C. Distribution State Estimator Module (DSEM)

The DSEM estimates the load demand at each bus. This module employs the Weighted Least Square (WLS) algorithm...
for DSE. The WLS algorithm uses weights to ensure that more accurate measurements are more significant in the estimation process, i.e., they have higher weights. The \(mx1\) vector of measurements for the DSE, \(Z\), is presented in (2).

\[
Z_i = h_i(x) + r_i, \quad i = 1, 2, ..., m
\]  

(2)

where, \(X\) is the state vector of the system, \(h_i(x)\) is the nonlinear function of the system state and \(r_i\) is the assumed error vector with a standard Gaussian distribution of zero mean and \(\sigma^2\) variance. The error vector of (2) is defined in (3) and this can be minimized using the objective function given in (4).

\[
r_i = Z_i - h_i(x), \quad i = 1, 2, ..., m
\]  

(3)

\[
J(x) = \sum_{i=1}^{m} (Z_i - h_i(x))^2
\]  

(4)

where, \(R_{ij}\) is a diagonal matrix of \([1/\sigma_{ij}^2\), \(1/\sigma_{j}^2\), \(1/\sigma_{m}^2\)] and \(\sigma_{m}^2\) is the variance of the \(m^{th}\) measurement error. Then, the state vector, \(X\), can be obtained by solving (5), iteratively.

\[
\begin{bmatrix} G(x) \end{bmatrix}^{\Delta x_{k+1}} = \begin{bmatrix} H(x^k) \end{bmatrix}^T \begin{bmatrix} R \end{bmatrix}^{-1} \begin{bmatrix} Z - h(x^k) \end{bmatrix}
\]  

(5)

where, \(H(x)\) is the Jacobian matrix of the nonlinear function (Jacobian matrix of \(h_i(x)\)) and \(G(x)\) is the Gain matrix, which is formulated in (6):

\[
\begin{bmatrix} G(x) \end{bmatrix} = \begin{bmatrix} H(x^k) \end{bmatrix}^T \begin{bmatrix} R \end{bmatrix}^{-1} \begin{bmatrix} H(x^k) \end{bmatrix}
\]  

(6)

The proposed DSE finds the optimal estimate of the power system state by minimizing the error vector. The measurement matrix of the proposed DSE is composed of a variety of measurements such as line power flows, bus power injections, bus voltage magnitudes and line current flows. However, constructing the measurement matrix requires the combination of real-time measurements and pseudo measurements. In this method, pseudo measurements have been used to improve the convergence properties of the DSE. The problem of the sparse nature of \(h(x)\) is also solved by using pseudo measurements.

The real and reactive power injection equations at bus \(i\), \(P_i\) and \(Q_i\), are defined as follows:

\[
P_i = \sum_{j=1}^{m} (G_{ij} \cos \theta_{ij} + B_{ij} \sin \theta_{ij}) V_j
\]  

(7)

\[
Q_i = \sum_{j=1}^{m} (G_{ij} \sin \theta_{ij} - B_{ij} \cos \theta_{ij}) V_j
\]  

(8)

where, \(G_{ij}\) is the conductance between bus \(i\) and bus \(j\), \(B_{ij}\) is the susceptance between bus \(i\) and bus \(j\), \(V_i\) is the voltage magnitude at bus \(i\), and \(\theta_{ij}\) is the phase angle between the voltages at bus \(i\) and bus \(j\).

The real and reactive power flow equations, \(P_{ij}\) and \(Q_{ij}\), between bus \(i\) and \(j\) are defined as follows:

\[
P_{ij} = V_i^2 (G_{ij} + G_{ij}) - V_j (G_{ij} \cos \theta_{ij} + B_{ij} \sin \theta_{ij})
\]  

(9)

\[
Q_{ij} = -V_i^2 (B_{ij} + B_{ij}) - V_j (G_{ij} \sin \theta_{ij} - B_{ij} \cos \theta_{ij})
\]  

(10)

In order to solve (5), the power flows and injections are used to build the measurement matrix \((h_i(x))\).

A flowchart of the execution of the DSEM is depicted in Fig. 6. It should be noted that the injections at each bus are updated using load models and the new calculated values of the voltage magnitudes and angles. Finally, the estimated value of the power consumption at each bus is sent to the LSCM to ensure the correct amount of load is shed.

D. Load Shedding Controller Module (LSCM)

The load shedding controller module is responsible for estimating the power imbalance in the microgrid. When delivering an event based load shedding action the LSCM uses the pre-event power flow on the element that has been lost (e.g., the point of connection to the main system, PCC, or a monitored generator) as the power imbalance.

When delivering a response based load shedding action the LSCM uses the COI ROCOF to estimate the power imbalance according to the following formula [4, 5].

\[
\Delta P = 2 \sum_{i=1}^{N_{gen}} H_i \frac{df_c}{f_{in}}
\]  

(11)

where, \(\Delta P\) is the power imbalance, \(H_i\) is the inertia constant of the \(i^{th}\) generator, \(f_{in}\) is the rated frequency, \(f_c\) is the frequency of the center of inertia, and \(N\) is the number of generators.

The LSCM determines the power imbalance immediately; however, the load shedding action is only initialized when the ROCOF is less than zero and the system frequency is below 49.5 Hz. During the simulation presented here a delay time of 100 ms is included to account for the delays involved in communication, calculation and circuit breaker operation [15].

An important feature of the LSCM is that it sheds the loads according to a priority sequence, i.e. the lower priority loads are shed first (the loads have been classified as vital, semi-vital and non-vital).
IV. TEST SYSTEM

The proposed CAULSC has been tested using a full scale model of a part of the Malaysian 11 kV distribution system. It consists of 102 buses, 79 lumped loads (modelled as static impedances) and 9 mini hydro generators, as depicted in Fig. 7. To provide voltage support, capacitors banks have been installed at buses 85 and 72 with ratings of 0.3 Mvar and 0.5 Mvar, respectively. In this test system, the total load is equal to 13.07 MW. There is 10.1 MW of DR generation and 3 MW of in feed from the Grid. Fiber optic communication infrastructure is assumed for this distribution network, this is in accordance with current practices in Malaysia [23, 24].

Table I shows the generator, excitation system and governor models for each generator in this study, these models are described in 0. Nine mini hydro generators are installed as part of five hydro power stations. Fixed speed induction generators are connected at bus 101 and bus 102. The system has 8 real-time measurement units (black ovals in Fig. 7) and 15 remote control switchgears (black squares in Fig. 7).

Table I: Summary of Generating Units

<table>
<thead>
<tr>
<th>Bus Number</th>
<th>Power Station</th>
<th>Inertia (H)</th>
<th>Exciter</th>
<th>Governor</th>
</tr>
</thead>
<tbody>
<tr>
<td>94</td>
<td>Synchronous Generators 8 &amp; 9 (2*5.5 MW)</td>
<td>4</td>
<td>Exac1</td>
<td>HYGOV</td>
</tr>
<tr>
<td>95</td>
<td>Synchronous Generators 4 &amp; 5 (2*2.75 MW)</td>
<td>3.5</td>
<td>Exac1</td>
<td>HYGOV</td>
</tr>
<tr>
<td>99</td>
<td>Synchronous Generators 1, 2 &amp; 3 (3*300 kW)</td>
<td>3</td>
<td>Exac1</td>
<td>HYGOV</td>
</tr>
<tr>
<td>100</td>
<td>Induction Generator 6 &amp; 7 (500 kW) &amp; (800 kW)</td>
<td>2.5</td>
<td>n/a</td>
<td>n/a</td>
</tr>
</tbody>
</table>

V. VALIDATION OF THE DISTRIBUTION STATE ESTIMATOR

The state estimator in this manuscript assumes that two types of measurement devices are used, i.e. Real-time and Pseudo measurement devices. Real-time measurement devices (PMUs) are installed in the main substations that contain the DRs point of connection or distribution transformer bus-bars. Pseudo-measurements are commonly used by utilities [25]. In this study they were obtained from power utility in Malaysia and they are related to measurements at load buses. Hence, these measurements can be used to increase the accuracy of the DSE, the system observability and the convergence of DSE.

The Distribution State Estimator Module (DSEM) is a key part of the proposed controller. The accuracy of its estimation of the load injections directly influences the success of the shedding action. To verify the accuracy of the DSE method two different ranges of real-time measurement errors in the voltage magnitude are studied, these are +/-0.004 and +/- 0.0004. Furthermore, errors are included in the line power, current flow and bus power injection measurements. Random errors that have zero mean and the following standard deviations are used (σVoltage=0.004, σInjection=0.01 and σflow=0.008) [26].

Figs. 8 and 9 compare real and estimated values of the active and reactive power consumptions at each bus. Furthermore, the accuracy of the DSE is assessed using the squared residuals of the estimated and exact values. These are 0.4504 and 0.3719 for errors of +/-0.004 and +/- 0.0004, respectively. However, there are large errors at buses 12, 13 and 14 (these are identified with the red ellipse in Fig. 7) due to the transformer at bus 3. In this SE, there is a lack of accuracy for those buses that are close to a transformer and lack a measurement device. These kinds of errors could be reduced by installing additional measurement devices.

Fig. 7. Distribution network test system.
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1.5
2.5
3.5
4.5
5.5
6.5
7.5
8.5
9.5
Error Value of 0.4e-3
Error Value of 4e-3
Real Data

Fig. 8. Estimated and exact value of active power on customer loads.

Fig. 9. Estimated and exact value of reactive power on customer loads.

Furthermore, in the future, the errors in the DSE output could be used when selecting which loads to shed, i.e. shed those loads that are thought to have the most accurate estimates first. This would help to deliver a more secure and optimal shedding by avoiding under/over shedding, both of which would be a threat to the success of the UFLS action and, consequently, the security of the microgrid. The average execution time of the proposed DSE (for 100 iterations) is 0.189 seconds using a PC (3.06 GHz CPU, 3 GB RAM).

The average time for reading and communication of 8 real-time measurements is considered to be 100 ms in this microgrid [25]. The monitoring scheme consists of only a single layer of data concentration, with all PMUs directly connected to it and the DSEM is executed locally. This is in contrast to the multi-level hierarchies that will exist for transmission systems that may result in significant delays, particularly at the higher levels of the hierarchy [27].

VI. VALIDATION OF THE PROPOSED METHOD

The proposed CAULSC is validated here using three test cases of the system depicted in Fig. 7:

A. Microgrid islanded from the grid at \( t = 5 \) s;

B. Loss of synchronous generator number 8 at \( t = 90 \) s after islanding at \( t = 5 \) s;

C. Load increase of 1.1 MW in the microgrid at bus 11 at \( t = 90 \) s after islanding at \( t = 5 \) s.

In each case the islanding operation is simulated by opening the grid circuit breaker at time \( t = 5 \) s. These test cases were chosen to demonstrate the ability of the controller to adapt the amount of shedding to the contingency and correctly prioritize the loads that are shed. A comparison is made with the proposed method and an adaptive UFLS scheme that uses 6-steps of shedding at 49.5, 49.2, 48.8, 48.5, 48.2 and 47.8 Hz. Another scheme which is compared with the proposed method is a conventional 15-step UFLS scheme that acts at 49.5, 49.4, 49.3, 49.2, 49.1, 49.0, 48.9, 48.8, 48.7, 48.6, 48.5, 48.4, 48.3, 48.2 and 48.1 Hz. The conventional 15-step UFLS scheme is the scheme that is used for conventional load shedding in the transmission network of Malaysia [28]. Table II presents the priority and consumption of each load.

<table>
<thead>
<tr>
<th>Rank</th>
<th>Priority</th>
<th>Power (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Non-vital</td>
<td>0.19</td>
</tr>
<tr>
<td>2</td>
<td>Non-vital</td>
<td>0.04</td>
</tr>
<tr>
<td>3</td>
<td>Non-vital</td>
<td>0.04</td>
</tr>
<tr>
<td>4</td>
<td>Non-vital</td>
<td>0.1</td>
</tr>
<tr>
<td>5</td>
<td>Non-vital</td>
<td>0.12</td>
</tr>
<tr>
<td>6</td>
<td>Non-vital</td>
<td>0.11</td>
</tr>
<tr>
<td>7</td>
<td>Non-vital</td>
<td>0.19</td>
</tr>
<tr>
<td>8</td>
<td>Non-vital</td>
<td>0.34</td>
</tr>
</tbody>
</table>

A. Microgrid islanded from the grid

In this case, the islanding operation of the microgrid is simulated. The total load demand prior to islanding is 15.62 MW (this value excludes network losses; with losses, it is equal to 16.16 MW). The Grid and DRs supply the microgrid with 3.09 MW and 13.07 MW of active power, respectively. Subsequent to being islanded, the system frequency begins to decline in response to the excess of load. In this scenario, the DMS automatically initiates its event-based strategy to limit the further decline in frequency. The power imbalance is determined by the ECM based on the power flow prior to the beaker opening and is sent to the LSCM. Hence, the loads ranked 1 to 9 are shed at \( t = 5.88 \) s (as per Table II) during the first stage of the shedding.

The first stage of shedding failed to provide a sufficient improvement in the frequency, so the controller initiated a second stage and the load ranked 10th was shed. The frequency response is shown in Fig. 10 and it drops to 48.92 Hz, despite the shedding at 49.5 Hz and 49 Hz. The frequency continues to fall after the shedding due to the slow response of the hydro governor to sudden changes.

Fig. 10. System frequency response for Case A.

Fig. 11 shows the change in active power dispatched before and after the load shedding. As previously mentioned, DR active power generation is equal to 13.07 MW prior to islanding and the grid in feed is 3.09 MW. The grid in feed falls to zero when the islanding occurs and the DR active
power generation is increased to compensate. The LSCM sheds 1.66 MW of load in two steps, as in Fig. 11.

Fig. 11. DR and grid active power generation for Case A.

B. Loss of synchronous generator after islanding

The loss of one generator (DR 8) is simulated at $t_2 = 90s$ when the system was islanded, as described in Case A. The frequency response is shown in Fig. 12. After the generation loss, the ECM detects the event and the DMS disconnects the loads ranked 11 through to 14 in the first stage of shedding and the load ranked 15th in the second stage of shedding, the loads ranked 1 to 10 were previously disconnected in Case A. The minimum system frequency after the disturbance was 48.9 Hz and it returned to above 49.5 Hz within 5 seconds.

Fig. 13 presents the active power generation of the DRs in the microgrid. After the generator trips (DR 8 at $t_2 = 90s$) the active power generation of the DRs in the microgrid is 11.09 MW. When DR 8 is tripped the distribution network loses 4.18 MW of its active power generation (around 30% of the microgrid load). The loss of so much generation has a significant impact on the operation of the islanded microgrid.

A comparison of the proposed scheme with the adaptive 6-step UFLS scheme and the conventional 15-step UFLS scheme are shown in Fig. 14. The proposed scheme limits the frequency deviation after the islanding event to 48.92 Hz, whereas the adaptive 6-step and conventional 15-step UFLS allow deviations of 48.78 Hz and 48.59 Hz, respectively. After the generator trip (DR 8 at $t_2 = 90s$), system frequency falls to 48.9, 48.11 and 47.60 Hz for the proposed, adaptive and conventional load shedding schemes, respectively. The amount of load shed for each method is presented in Table III.

Fig. 15 shows the system frequency versus ROCOF for the simulation time period. It can be seen that for both large disturbances the CAULSC takes an effective control action when the system frequency goes below 49.5 Hz (frequencies less than 49.5 Hz are marked in red in this figure) and the system frequency returns to the acceptable range.

<table>
<thead>
<tr>
<th>Cases</th>
<th>Power Imbalance</th>
<th>Proposed Load Shedding Scheme</th>
<th>Load Shedding (6-Step)</th>
<th>Load Shedding (15-Step)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Islanding event</td>
<td>3.09 MW</td>
<td>1.66 MW</td>
<td>1.8 MW</td>
<td>1.28 MW</td>
</tr>
<tr>
<td>Generator tripping</td>
<td>4.18 MW</td>
<td>3.67 MW</td>
<td>3.519 MW</td>
<td>4.04 MW</td>
</tr>
</tbody>
</table>

Fig. 12. System frequency response for Case B.

Fig. 13. Active power generation for Case B.

Fig. 14. Comparison of system frequency response.

Fig. 15. System frequency and ROCOF for Case B, the yellow planes mark the security limits of the microgrid frequency.
A plot of frequency versus ROCOF is presented in Fig. 16 for Case B [29, 30]. Point N represents the normal condition of the system with frequency equal to 50 Hz. After an islanding event, the frequency will begin to drop, but the ROCOF experiences a step change to point A. From point A to point B, the under-frequency governor control of the generators will initiate. The UFLS action causes a positive step in ROCOF at point B and C. At point C, the frequency has reached its minimum value and will then begin to recover. In the second event, generator tripping, the ROCOF experiences a more severe drop to point D. In this case, the rate of frequency change is larger; as such, the frequency falls further to 49.2 Hz, point E. Then, there is a step in ROCOF due to load shedding at points E and F. Point F, is the minimum frequency and the frequency then recovers to a normal condition at N.

![Fig. 16. System frequency versus ROCOF for Case B.](image)

C. Load increase in the microgrid after islanding

In this case, the microgrid is disconnected from the grid at $t_1 = 5s$ and a load increase of 1.1 MW occurs at $t_2 = 90$ (s). Prior to the load increase, the total load was 14.31 MW.

After the load has been increased, the FCM detected that the ROCOF is below zero. Consequently, the LSCM defined a response based strategy using the post-disturbance ROCOF at $t=90^*$ and (11). For this case, the frequency response of the microgrid is depicted in Fig. 17. The system frequency response of the microgrid has been limited to 49.44, 49.47 and 49.42 Hz for the proposed method, 6-step and 15-step UFLS schemes, respectively. It can be noted that the frequency response for each of the load shedding methods is almost same in this case (in terms of the maximum deviation); however, the proposed controller has shed less load compared to the 6-step and 15-step UFLS schemes. The DMS disconnected the load ranked 11th in response to the load increase (the loads ranked 1 to 10 were disconnected in Case A) and the amount of load shed is presented in Table IV. It can be observed that the 6-step load shedding scheme sheds more load in this scenario.

Fig. 18 shows the change of active power dispatched before and after the load shedding for the grid disconnection and load increase. It can be seen that for each disturbance the DR power generation increases. Fig. 19 illustrates the system frequency and its rate of change after a disturbance in the network versus time. The effectiveness of the proposed controller based on adaptive UFLS and DSE can be seen in this figure, which shows that CAULSC can perform adaptive actions that return the system frequency to its secure range.

![Fig. 17. System frequency for Case C.](image)

![Fig. 18. DR and grid active power generation for Case C.](image)

![Fig. 19. System frequency and ROCOF for Case C.](image)

<table>
<thead>
<tr>
<th>Cases</th>
<th>Power Imbalance</th>
<th>Proposed Load Shedding Scheme</th>
<th>Load Shedding (6-Step)</th>
<th>Load Shedding (15-Step)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Islanding event</td>
<td>3.09 MW</td>
<td>1.66 MW</td>
<td>1.8 MW</td>
<td>1.28 MW</td>
</tr>
<tr>
<td>Load Increase</td>
<td>1.1 MW</td>
<td>0.15 MW</td>
<td>0.5 MW</td>
<td>0.37 MW</td>
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</tbody>
</table>

VII. CONCLUSION

This paper presents a Centralized Adaptive Under-frequency Load Shedding Controller (CAULSC) that uses the frequency and ROCOF of the system’s center of inertia and estimates of the load demand from a distribution state estimator to improve the frequency stability of microgrids.
CAULSC estimates the power imbalance in the system to adapt the amount of load shedding to the severity of the contingency. Furthermore, it selects the loads to be shed based on the priority of the loads, i.e. it sheds low priority loads first.

A distribution state estimator (DSE) is used here to overcome the dependency of existing microgrid adaptive load shedding schemes on the extensive deployment of new measurement devices. The results presented in Section V suggest that the accuracy of contemporary DSE methods, when supported by very few measurements, will be sufficient to provide the necessary accuracy for the proposed controller, even in the presence of high levels of errors. The DSE used here is applicable for mini-hydro type DR, which have a slower response than most other DR. However, significant work is required in the field of DSE to address the issues of intermittency and the fast response of inverter based DR.

The case studies presented show that CAULSC successfully protects the microgrid from dangerous frequency deviations by selecting a suitable level of shedding for both a generation loss and a load increase after the islanding of the microgrid.

Future work on adapting the total load shed and more intelligent ways to set the shed levels of each stage are recommended for microgrids load shedding. It is likely that the nature of microgrids will mean that these approaches will need to differ from those used at the bulk transmission level. However, given the scale of the research undertaken in the field of UFLS for transmission systems, an essential aspect of this future work will be understanding the extent to which the previous learning can be applied to microgrids.

If microgrids are to form an effective part of modern power systems then it is vital that they can survive being islanded from the main grid and continue to operate in a secure fashion after the loss of their grid connection. Adaptive controllers, like the proposed CAULSC, implemented in the distribution management system will play a key role in achieving this.

REFERENCES