A Coordinated Voltage–Frequency Support Scheme for Storage Systems Connected to Distribution Grids

Anastasis Charalambous Ⓢ, Student Member, IEEE, Lenos Hadjidemetriou Ⓢ, Member, IEEE, Elias Kyriakides Ⓢ, Senior Member, IEEE, and Marios M. Polycarpou Ⓢ, Fellow, IEEE

Abstract—Power electronics converters are utilized for interconnecting distributed energy storage systems into the grid. These converters can support the stability of the power system under abnormal grid conditions. In this article, a new coordinated voltage–frequency support strategy is proposed for energy storage systems considering the reactance-to-resistance ratio of the grid impedance. Unlike conventional support schemes for transmission grids, where voltage and frequency support is decoupled, the proposed strategy considers the coupling between voltage and frequency due to the resistive characteristics of the grid impedance in low-voltage distribution grids. An advanced frequency support scheme is also developed considering both droop-based frequency support and virtual inertia control for improving frequency stability. The proposed strategy ensures a fair compensation between voltage and frequency support by utilizing an adaptive gain that is calculated online according to the short-circuit fault characteristics. Simulations and experimental tests are carried out using a laboratory setup to validate the proposed strategy.

Index Terms—Control of power electronics, distribution grids, energy storage, fault ride-through, flywheel, frequency–voltage support.

I. INTRODUCTION

The low-voltage distribution grid (LVDG) is currently undergoing substantial challenges due to the massive integration of power-electronics-based generation (e.g., wind turbines, photovoltaics, etc.) [1]. Particularly, the voltage and frequency stability is among the major concerns for the system operators as inertia levels of the system are dramatically being reduced [2]. Due to this reduction, power systems are becoming more vulnerable, and therefore, advanced control schemes need to be developed for supporting the grid under high penetration of renewable energy sources. As a result, the capabilities of power electronic converters and the flexibility offered by energy storage systems need to be exploited to secure the operation of the grid by designing tailor-made support strategies.

Grid codes have already been developed by several countries to obligate inverters, connected to the transmission grid, to provide support during abnormal conditions (e.g., short-circuit faults, equipment failures, etc.) [3], [4]. More specifically, commercial photovoltaic and wind farm inverters are required to provide voltage and frequency support during short-circuit grid faults (e.g., single-phase-ground, three-phase-ground, etc.) by controlling the reactive and active power, respectively [5]–[7]. Furthermore, the synthetic inertia provision by wind turbines has been successfully demonstrated in enhancing the frequency stability, and widespread adoption is expected in the coming years [8]. The distribution grid-connected inverters are either disconnected from the grid during abnormal conditions or remain connected to provide support. In [4]–[7], the support scheme characteristics are inherited by the transmission grid codes. However, such an approach does not provide maximum support to the LVDG, and new grid codes should be developed dedicated for the distribution grid [1].

In the literature, there exist several advanced schemes for supporting the grid voltage under balanced and unbalanced conditions (see, e.g., [9]–[11]). However, some of the unique characteristics of the distribution network are not considered in the above studies. The resistive nature of the distribution lines alongside the flexible capabilities of storage systems should be taken into account in order to develop specialized control strategies for inverter-based storage systems connected to LVDG. A key issue is that the decoupled control approach is not effective in LVDG due to the low inductance-to-resistance ratio \(X/R\) of the grid impedance. Consequently, an effective voltage support is required not only with reactive power, but also with active power provision. An innovative current reference generator considering the grid impedance is proposed in [12] for balanced and unbalanced conditions; however, no voltage support is considered. Furthermore, an optimization algorithm is developed in [13] to maximize the voltage support and unbalance compensation in LVDGs, where the converter supports the voltage with its rated current regardless of the

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Fig. 1. Structure of the FESS with its associated controllers.

Fig. 2. Conventional voltage and frequency support schemes. (a) Voltage support. (b) Frequency support.

voltage drop intensity. However, this approach may introduce large discontinuities in the voltage support concept that can impose intense undesired oscillations on the voltage. The authors in [14] proposed a voltage support scheme for eliminating the discontinuities of the existing grid codes [see Fig. 2(a)] that can reduce the intensity of the oscillations, which can appear due to the deadband zone. A strategy that can provide both voltage and frequency support is proposed for energy storage systems in [15]. The authors developed an advanced control strategy that considers the characteristics of storage systems (i.e., state of charge); however, the resistive nature of the LVDG is not considered.

In recent years, there has been an increasing interest for power-electronics-based generation to mimic synchronous generation. For this reason, the virtual synchronous generator (VSG) concept has been developed in the literature [16]–[19]. There are many different variations of VSG schemes (e.g., synchroconverter [20], synchronous generator emulation control [21], etc.). The backbone of these control schemes is that they are designed based on synchronous machine models. It should be noted that the inertia emulation and damping of electromechanical oscillations are common features of every VSG implementation. Some more advanced VSG control schemes also consider the coupling between active and reactive power [22] and the harmonic current suppression [23]. The significant improvements on system frequency stability with the use of VSG control, compared with the droop-controlled inverters, are demonstrated in [24].

In this article, the transmission grid voltage support is modified to provide support to the LVDG where the $X/R$ ratio of the grid impedance is considerably lower than in the transmission network. The proposed voltage support scheme eliminates the discontinuities that exist in the current grid codes. An optimal voltage support is achieved by regulating both active and reactive powers, since both of them can support the voltage in a highly resistive distribution grid. In addition, the primary frequency support [see Fig. 2(b)] is enhanced with virtual inertia control loop to emulate the behavior of synchronous generators. Therefore, the rate of change of frequency (RoCoF) and the steady-state frequency deviation can be minimized, and as a result, the frequency stability is improved. Then, a coordinated control scheme is developed for fair allocation between voltage and frequency support based on an adaptive gain calculated according to the short-circuit fault characteristics. As a result, the proposed solution inherits the capabilities of VSG control in terms of frequency support, while it is able to provide maximum voltage support for inductive–resistive grids due to the consideration of the $X/R$ ratio. Finally, the proposed coordinated voltage–frequency support scheme is validated using experimental tests, and its impact is evaluated in a low-voltage distribution feeder.

The main contributions of this article are as follows:

1) design of a coordinated voltage–frequency support considering an optimum voltage support according to the $X/R$ characteristic of the grid impedance and an advanced frequency support;
2) elimination of the discontinuities to avoid oscillations and stability issues;
3) according to the fault characteristics, online calculation of an adaptive weight for fair allocation between the voltage and frequency support.

The rest of this article is organized as follows. Section II describes the existing voltage and frequency support grid codes for transmission grids. The proposed support strategy is presented in Section III, and the simulation results of a flywheel energy storage system (FESS) enhanced with the proposed voltage–frequency support strategy are presented in Section IV. The proposed strategy is validated in a prototype experimental setup in Section V. The impact of the proposed strategy on the LVDG is presented in Section VI. Finally, Section VII concludes this article.

II. PROBLEM FORMULATION

A. Three-Phase FESS

Fig. 1 shows the general structure of a FESS with its associated controllers connected with the power grid through the grid impedance. A machine-side converter (MSC) controls the operation (i.e., charging/discharging) of the permanent magnet synchronous generator. A dc-link capacitor interconnects the MSC with the grid-side converter (GSC), which controls the
dc-link voltage to balance the power flow in the system. Then, an LC filter is used to reduce high-frequency harmonics. Finally, the FESS is connected to the main grid at the point of common coupling (PCC) through an inductive–resistive grid impedance.

B. Grid Code Requirements for Voltage Support

The provision of voltage support, according to the existing grid codes, is realized by the injection of reactive current ($i_Q$), which is defined as the current that lags the voltage by $90^\circ$. The reference reactive current $i_{Q_0}$ is defined as

$$i_{Q_0} = \frac{k_v (V_n - V)}{|i_{Q_0}|}$$

(1)

where $V_n$ and $V$ are the magnitude of the nominal voltage and of the voltage at the PCC, respectively. $i_{Q_0}$ represents the reactive current during normal operation (i.e., prior to the fault). The voltage droop gain ($k_v$) determines the voltage support intensity and should satisfy $k_v \geq 2$ according to the grid codes [3]. The provision of voltage support is activated when the voltage exceeds a predefined deadband zone, as shown in Fig. 2(a). $V_L$ and $V_H$ denote the lower and upper bounds of the deadband zone, respectively and $V_{I_{\min}}$ and $V_{I_{\max}}$ represent the minimum and maximum voltage limits, respectively, where the rated current injection ($I_n$) is reached. During the voltage support provision, the converter current ratings should be selected so as to avoid overcurrent protection tripping and excessive thermal loading. Hence, in the support scheme, the active current ($i_P$), which is defined as the current vector that is in line with the voltage vector and is related to the active power injection, should be limited according to the rated current of the inverter, as follows:

$$|i_P| = \sqrt{T_n^2 - |i_Q|^2}.$$  

(2)

C. Grid Code Requirements for Frequency Support

Frequency stability may also deteriorate due to the decrease of the physical inertia of the system caused by the high penetration of power-electronics-based distributed resources. Hence, load shedding or renewable energy curtailment is implemented to deal with under- and overfrequency disturbances, respectively. Fig. 2(b) shows a frequency support strategy designed for storage systems [15]. The active power reference ($P^*$) is regulated according to the frequency deviation ($\Delta f$) and the frequency droop gain ($k_f$), which defines the intensity of the frequency support:

$$P^* = P_0 + k_f \Delta f$$

(3)

where $P_0$ represents the active power prior to the frequency event. The frequency deviation $\Delta f$ is given by

$$\Delta f = \begin{cases} f_L - f, & f \leq f_L \\ f_H - f, & f \geq f_H \\ 0, & f_L \leq f \leq f_H \end{cases}$$

(4)

where $f$ represents the operating frequency, and $f_L$ and $f_H$ denote the lower and upper bounds of the deadband zone, respectively. A typical setting that is used by the system operators for the frequency droop gain is 40% of rated power per Hertz [3]. Furthermore, according to the grid codes, the inverter should be disconnected from the grid when $f \leq f_{\min}$ or $f \geq f_{\max}$. The $f_{\min}$ and $f_{\max}$ are design frequency thresholds that denote the minimum and maximum frequencies, respectively, that the inverter must remain connected to the grid.

It should be highlighted that when a short-circuit occurs, it can affect both voltage and frequency [6, 14, 15]. Therefore, a high value of voltage droop gain will deteriorate the frequency support capability, while a high-frequency droop gain will deteriorate the voltage support capability. For instance, in case $k_v = 5$, any voltage drop higher than 0.2 p.u. will require a full reactive current support, according to (1), and as a result, the active current provision will be zero to avoid inverter limit violations. This will have a significant impact on the frequency stability especially in weak grids where the system’s inertia is low, since even the prefault active current will not be delivered by the inverter. Therefore, a fair compensation of voltage and frequency support is essential to secure proper grid support.

III. COORDINATED VOLTAGE–FREQUENCY SUPPORT SCHEME

The conventional support strategies (see Section II) are effective in the case of the transmission grid, where the inductive characteristics of the transmission lines decouple the voltage and frequency control. In the LVDG, the resistive characteristics of the distribution line do not allow a decoupled control between voltage and frequency, and thus, the support schemes for distribution grids need to be revised [1], [25]. In this case, both active and reactive powers can contribute toward the voltage stability enhancement by considering the inductance-to-resistance ratio of the grid impedance.

A. Voltage Support Scheme

The aim of the proposed scheme is to maximize the positive-sequence voltage at the PCC; therefore, only positive-sequence voltage and current will be considered in the following analysis. It should be highlighted that by maximizing the positive-sequence voltage in case of double-phase faults, the unfaulted phase may experience overvoltage conditions. This may happen only in local level when high inverter ratings are utilized that can significantly alter the voltage at the PCC to cause an overvoltage condition ($V > V_H$). For addressing this issue, the negative-sequence voltage should be minimized for balancing the phase voltages [13]; however, this is out of the scope of this article. The positive-sequence voltage vector ($v$) at the PCC and the positive-sequence current vector ($i$) injected by the inverter are defined as

$$v = \begin{bmatrix} v_d \\ v_q \end{bmatrix} \text{ and } i = \begin{bmatrix} i_d \\ i_q \end{bmatrix}$$

(5)

where $v_d$, $v_q$, $i_d$, and $i_q$ are the corresponding positive-sequence voltage and current expressed in the $dq$ frame, respectively. The positive-sequence voltage can be estimated using an advanced phase-locked loop (PLL) such as the decoupling network $\alpha \beta$ PLL (DN $\alpha \beta$ PLL), which can dynamically analyze the voltage into its positive- and negative-sequence components [26]. The
current can be also analyzed into its sequence components (for obtaining the positive-sequence current) using the decoupling network in [27].

An inverter is connected to the grid through a grid impedance \( Z = R + jX \). Hence, the voltage vector at the PCC can be expressed as

\[
v = v_g + iR + j(iX) \tag{6}
\]

where \( R \) is the grid resistance, \( X \) is the grid reactance, and \( v_g \) represents the grid voltage vector. At the transmission level, the term \( iR \) can be neglected since it is very small compared to the term \( jIX \), and the voltage support can be achieved when only reactive current is injected. However, in the case of LVDGs, the \( X/R \) ratio is considerably lower, and both terms \( iR \) and \( jIX \) need to be taken into account in the design of the voltage support strategy. By considering (7), an optimized phase angle \( (\theta_{opt}) \) for the current injection is defined as

\[
\theta_{opt} = \arctan(X/R). \tag{7}
\]

The optimized phase angle ensures the optimal voltage support that maximizes the positive-sequence voltage according to the \( X/R \) characteristics of the distribution line for undervoltage events. In general, the current angle \( (\theta) \) that provides the maximum support to both undervoltage and overvoltage events is given by

\[
\theta = \begin{cases} 
\theta_{opt}, & V \leq V_L \\
\theta_{opt} - 180^\circ, & V \geq V_H 
\end{cases} \tag{8}
\]

It should be highlighted that the optimum angle is altered according to the frequency variations due to the reactance term \( X = 2\pi f L \), where \( L \) is the grid inductance. Fig. 3 demonstrates the error in the optimum angle when a constant frequency of \( f = 50 \text{ Hz} \) is assumed compared with the case when the actual grid frequency is used. It should be highlighted that the error is calculated only for the operating region of the inverter (47 \( \leq f \leq 52 \text{ Hz} \)). As can be seen, the error can be up to 2\%, and as a result, the actual frequency of the grid is utilized for the estimation of the optimum angle in this article. However, in case one requires to simplify the algorithm, the use of constant frequency can be considered as a reasonable assumption.

In this article, the knowledge of the grid impedance ratio is assumed to be known \textit{a priori} and stored in the inverter controller. In this case, the grid impedance can be measured using impedance measurement devices and used as an initialization parameter of the inverter. However, in case that the grid impedance is not known \textit{a priori}, it can be estimated by the inverter using the methodologies developed in [28]–[30]. The estimation methods require the inverter to inject a harmonic or negative-sequence current into the grid and then measure its impact on the PCC voltage for estimating the grid impedance. It should be noted that the estimation in this case can be performed periodically to capture sudden changes of the grid impedance characteristics (i.e., islanding transitions in microgrids applications), as mentioned in [13].

The voltage support scheme should generate the reference current for the inverter. Therefore, the current reference vector during the voltage support mode \( (I_v^*) \) can be defined by the current magnitude \( (I_v^*) \) and angle \( (\theta_v^*) \). A droop-based control approach is implemented for adjusting both magnitude and angle according to the voltage deviation \( (\Delta V) \) as follows:

\[
I_v^* = \begin{cases} 
I_{o} + k_i \Delta V, & V_{Lmin} < V < V_L \text{ or } \\
I_{n}, & V_H < V < V_{Hmax} \\
V \geq V_{Hmax} \text{ or } V \leq V_{Lmin}. 
\end{cases} \tag{9}
\]

\[
\theta_v^* = \begin{cases} 
\theta_o + k_\theta \Delta V, & V_{L\theta min} < V < V_L \text{ or } \\
\theta_{opt}, & V_H < V < V_{H\theta max} \\
\theta_{opt} - 180^\circ, & V \geq V_{H\theta max} 
\end{cases} \tag{10}
\]

where

\[
\Delta V = \begin{cases} 
V_L - V, & V \leq V_L \\
V - V_H, & V \geq V_H \tag{11}
\end{cases}
\]

and

\[
k_\theta = \frac{\Delta \theta_{min}}{\Delta V}. \tag{12}
\]

The variables \( I_o \) and \( \theta_o \) represent the magnitude and angle of the current during normal operation, respectively. \( V_{L\theta min} \) and \( V_{L\theta max} \) denote the minimum and maximum voltage limits that reach the optimum voltage support \( (\theta_v^* = \theta_{opt} \text{ or } \theta_v^* = \theta_{opt} - 180^\circ) \), respectively. \( \Delta \theta_{min} \) represents the minimum angle difference or the minimum locus of the support angle \( \theta_v^* \) from the initial angle \( \theta_o \) toward the optimal angle \( \theta \) and is defined as

\[
\Delta \theta_{min} = \text{mod} (\theta + 180^\circ - \theta_o, 360^\circ) - 180^\circ. \tag{13}
\]

The voltage deviation that is required to reach the current angle \( \theta \) that ensures maximum voltage support is \( \Delta V_\theta = V_L - V_{L\theta min} = V_{H\theta max} - V_H \). Hence, the angle droop gain \( (k_\theta) \) is adaptively altered according to the prefault angle to ensure that the reference voltage angle reaches the current angle \( \theta \) with the minimum angle deviation. By utilizing (9) and (10), the proposed voltage support scheme eliminates the discontinuities that can appear when switching from normal operation mode to voltage support mode, and vice versa. This is achieved since the current magnitude and angle are linearly altered from the prefault values \( (I_o \text{ and } \theta_o) \) to the proper magnitude and angle while ensuring maximum voltage support for the LVDG. The discontinuities can create large oscillations on the grid voltage and the output power of the inverter due to the ON/OFF
actions of the voltage support scheme. In the existing grid codes [see Fig. 2(a)], a large discontinuity exists in the reactive current when the voltage deviation exceeds the deadband zone. In case the voltage deviation is small, this discontinuity can be enough to bring the voltage deviation inside the deadband zone, and as a result, the voltage support will be deactivated (500 ms after the voltage is within the deadband zone). The deactivation of the voltage support will bring again the voltage outside the deadband zone, and the voltage support will be activated again. This process will constantly be repeated, and as a result, significant oscillations on the voltage of grid will be arisen, as indicated in [14]. Therefore, the elimination of the discontinuities through the proposed scheme is considered an improvement over the existing support framework. The schematic representation of the proposed voltage support scheme is shown in Fig. 4.

### B. Frequency Support Scheme

The conventional frequency support scheme (as shown in Section II-C) is enhanced with virtual inertia control loop to improve the RoCoF of the grid. Virtual inertia control is proposed in the literature to enable power-electronics-based distributed generators to mimic the behavior of synchronous generators, which naturally respond to frequency deviations due to their rotating mass [31]–[33]. Hence, the main goal of frequency support is to minimize the RoCoF and steady-state frequency deviation by combining virtual inertia and droop-based control, respectively. The droop-based control acts based on the frequency deviation (i.e., slower dynamics), while virtual inertia control acts based on the derivative of the frequency (i.e., faster dynamics); as a result, remarkable improvements can be achieved in terms of frequency stability.

The reference current vector during frequency support mode ($I^*_f$) can be expressed in polar coordinates, as the reference magnitude ($I^*_f$) and reference angle ($\theta^*_f$) during frequency support. The current magnitude is altered according to the frequency-based droop gain ($k_f$) and the RoCoF-based virtual inertia gain ($k_{vi}$) as follows:

$$I^*_f = I_o + k_f |\Delta f| + k_{vi} \left| \frac{df}{dt} \right|.$$  \hspace{1cm} (14)

The frequency droop gain $k_f$ can be set according to the current grid codes, while the virtual inertia gain is determined from the swing equation as

$$k_{vi} = \frac{4H_{vi}I_n}{f_n}$$  \hspace{1cm} (15)

where $H_{vi}$ represents the virtual inertia constant and $f_n$ represents the nominal frequency of the grid ($f_n = 50$ Hz). The frequency support scheme requires the estimation of the frequency derivative, which can be prone to instabilities due to the amplification of noise. For the estimation of frequency derivative, the grid frequency is estimated through the PLL, and then, the derivative is calculated in discrete time. Thereafter, for ensuring stable operation, a low-pass filter with time constant of 1 s is applied on the derivative signal to remove the high-frequency components [33].

The frequency support is only related to the active power (or active current). Therefore, by adjusting only the magnitude of the frequency support, current would lead to an increase in the reactive power (or reactive current) as well, especially in cases where the inverter was injecting reactive power prior the fault. Therefore, the reference current angle during frequency support $\theta^*_f$ needs to also be altered to achieve an increase/decrease in active current only (in order to contribute toward the frequency stability enhancement) according to the event type. In case the reactive current prior to the event is not zero ($|i_{Q0}| = 0$), the reference angle is $\theta^*_f = 0^\circ$ or $\theta^*_f = 180^\circ$ for under- and overfrequency events, respectively. In case the reactive current prior to the event is not zero ($|i_{Q0}| \neq 0$), the reference angle is given by

$$\theta^*_f = \arctan \left( \frac{|i_{Q0}|}{|i_{P0}| + k_f |\Delta f| + k_{vi} \left| \frac{df}{dt} \right|} \right)$$  \hspace{1cm} (16)

where $i_{P0}$ represents the prefault active current. It should be noted that the reactive current remains the same according to the prefault conditions, while $\theta^*_f$ ensures an increase or decrease only of the active power keeping reactive power unchanged until the inverter reaches its current limits.

### C. Coordinated Voltage–Frequency Support

A coordination scheme between voltage support and frequency support is developed to provide a proper and fair compensation among these services under any grid conditions. According to the short-circuit fault characteristic, an adaptive weight (sharing constant) is calculated to ensure that voltage and frequency support are provided with priority given to the service that exhibits the most severe deviation. For that reason, the current vector during voltage/frequency or combined event ($I^*_{vf}$) can be expressed as a linear combination of the proposed voltage and frequency support schemes (see Sections III-B and III-C). Hence, the current magnitude ($I^*_{vf}$) and angle ($\theta^*_{vf}$) are defined as

$$I^*_{vf} = I_o + k_v |\Delta V| + k_f |\Delta f| + k_{vi} \left| \frac{df}{dt} \right|$$  \hspace{1cm} (17)

$$\theta^*_{vf} = k_s \theta^*_v + (1 - k_s) \theta^*_f.$$  \hspace{1cm} (18)
It should be noted that once the reference current and angle are estimated, they can be transformed from polar coordinates in the dq frame easily as given by

\[
\begin{bmatrix}
  i^*_{d-v} \\
  i^*_{q-v}
\end{bmatrix}
= \begin{bmatrix}
  I^*_{v} \cos \theta^*_{v} \\
  I^*_{v} \sin \theta^*_{v}
\end{bmatrix}.
\]  

(19)

The sharing constant \(k_s\) ensures a fair compensation between voltage and frequency support by adjusting the reference current angle, and it is given as

\[
k_s = \frac{\Delta V_{pu}}{\Delta V_{pu} + \Delta f_{pu}}.
\]  

(20)

It should be noted that the sharing constant should be in the range \([0, 1]\); therefore, \(\Delta V_{pu}\) and \(\Delta f_{pu}\) represent the normalized voltage and frequency deviations, respectively, which are given by

\[
\Delta V_{pu} = \frac{|V - V_n|}{V_n},
\]  

(21)

\[
\Delta f_{pu} = \begin{cases}
\frac{f_n - f_{min}}{f_{max} - f_{min}} & f \leq f_L \\
\frac{f_n - f_{max}}{f_{max} - f_{min}} & f \geq f_H.
\end{cases}
\]  

(22)

The RoCoF\(_{max}\) represents the maximum RoCoF that can be allowed by each system operator before disconnecting the inverter from the grid. In case \(k_s = 1\) (i.e., voltage event only), the reference current angle will be equal to the optimum angle determined according to the voltage support scheme. Hence, the coordinated voltage–frequency support scheme would operate as voltage support scheme according to Section III-A. If the sharing constant is equal to zero (i.e., frequency event only), the coordinated voltage–frequency support scheme would behave as a frequency support scheme (as in Section III-B). Finally, in case of a combined event \((0 < k_s < 1)\), the coordinated scheme can share the support intensity according to the severity of the event. Hence, a more appropriate grid support is provided without compromising one of the services.

IV. Simulations Case Studies

For validation purposes, the proposed support strategy is implemented on a 1.3-kW/2-kWh FESS with a rated speed of 14,000 r/min, which is modeled using MATLAB/Simulink. It should be highlighted that the proposed voltage–frequency support scheme can also be applied to any type of storage systems with power electronic interface (e.g., chemical batteries). The parameters used for the development of the simulation model are depicted in Table I. The impedance ratio in the simulation models is assumed to be known \(a priori\) and is used in the initialization phase. A detailed structure of the FESS and its associated controllers is illustrated in Fig. 1. The model consists of a permanent magnet generator, whose inertia also includes the flywheel mass inertia and a back-to-back two-level converter configuration along with their controllers.

An advanced current controller is implemented in the GSC to be able to inject/absorb perfectly balanced currents during normal and abnormal conditions. The current controller is designed in double synchronous reference frame (DSRF) with four proportional-integral (PI) controllers, as shown in Fig. 5. The positive-sequence current controller is used to regulate the main current injection (positive-sequence) and the negative-sequence current controller to compensate the unbalanced effects. In order to enable a balanced current injection/absorption during asymmetrical voltage faults, the negative-sequence reference currents were set to zero \((i^*_d = 0\) and \(i^*_q = 0)\). This current controller requires the estimation of the positive- and negative-sequence voltage, which can be achieved with an advanced synchronization unit such as the DN\(\alpha/\beta\) PLL [26]. The current also requires

| Switching frequency \(f_s\) | 3.45 kHz |
|-----------------------------|----------|
| MSC Current Controller \(k_p\) | 92.5, \(k_{i-MSC} = 13500\) |
| DN\(\alpha/\beta\) PLL \(k_p\) | 92, \(T_{i-PPLL} = 0.000235\) |
| GSC Current Controller \(k_p\) | 50, \(k_{i-pow} = 633.33\), \(k_{i-neg} = 633.33\) |
| LC filter \(R_L\) | 0.19 Ω, \(L_f = 15\) mH, \(C_f = 9.45\) μF |
| Grid Parameters \(V_n, f_n\) | 230 V, 50 Hz |
| Flywheel parameters \(V_L, V_H, f_L, f_H, \theta_{opt}, \theta_{max}\) | 9.09 pu, 1.15 pu, 72.2°, 115° |
| Voltage Support \(f_{min}, f_{max}\) | 47 Hz, 53 Hz |
| Frequency Support \(f_{L}, f_{H}\) | 49.8 Hz, 52.5 Hz |
| Synchronous generator \(H_G\) | 5 s, \(R_{gen} = 0.05\), \(T_{CG} = 0.2\) s, \(T_{CGH} = 0.4\) s |

![Positive sequence current controller diagram](https://example.com/positive_sequence_current_controller.png)

![Negative sequence current controller diagram](https://example.com/negative_sequence_current_controller.png)
to be analyzed into positive- and negative-sequence components to be fed into the DSRF current controller. A decoupling network as in [27] can be used to dynamically decompose the current into its sequence components. The operation of the current controller is enabled by using the transformation between positive sequence \((+\)) and negative sequence \((-\)) SRFs, and \(\alpha\beta\) frame transformations, as given by

\[
\begin{bmatrix}
T_{dq+} \\
T_{dq-}
\end{bmatrix} =
\begin{bmatrix}
\begin{array}{cc}
\cos \omega t & \sin \omega t \\
-\sin \omega t & \cos \omega t
\end{array}
\end{bmatrix}^T
\]

\[
\begin{bmatrix}
T_{\alpha\beta}
\end{bmatrix} =
\begin{bmatrix}
1 & \frac{1}{\sqrt{2}} & \frac{1}{\sqrt{2}} \\
0 & \frac{1}{\sqrt{2}} & -\frac{1}{\sqrt{2}} \\
\frac{1}{\sqrt{2}} & \frac{1}{\sqrt{2}} & \frac{1}{\sqrt{2}}
\end{bmatrix}
\]  

The outer controller of the GSC regulates the dc-link voltage \((V_{DC})\) to track its reference value \((V^*_{DC})\) by adjusting the \(d\)-axis positive-sequence reference current \((i^*_d)\) and, as a result, to regulate the positive-sequence active power injection. The \(q\)-axis positive-sequence reference current \((i^*_q)\) is determined either by the prefault \(q\)-axis positive-sequence current \((i^*_{q0})\) or by the positive-sequence reference current calculated by the proposed voltage–frequency support scheme \((i^*_{q-vf})\).

The MSC controller regulates the active power production using vector control to charge or discharge the FESS. More specifically with vector control, the \(d\)-axis is aligned with the rotor flux and the \(q\)-axis is \(90^\circ\) behind the \(d\)-axis to enable a decoupling control technique [34]. As a result, the torque production is associated with the \(q\)-axis current \((i^*_{q-m})\), while the \(d\)-axis current \((i^*_{d-m})\) does not contribute to the torque production, and it should be zero. The analysis of the current in the \(dq\) frame requires the rotor angle \((\theta_r)\), which can be estimated by integrating the rotor speed \((\omega_r)\), as shown in Fig. 1.

The analysis of the current in the \(dq\) frame enables the use of PI controllers for the current controller, which receives the reference \(q\)-axis current \((i^*_{q-m})\) from the outer level controller. The reference \(d\)-axis current \((i^*_{d-m})\) should be set to zero, since vector control requires that \(i^*_{d-m} = 0\). The \(q\)-axis is given by

\[
i^*_{q-m} = \frac{2}{3\omega_r \lambda} P^*
\]

where \(\lambda\) denotes the flux constant of the permanent magnet machine. The reference active power \((P^*)\) can be estimated either by the dispatch algorithm during normal operation or by the proposed voltage–frequency support scheme during abnormal conditions. The reference active power in case of voltage or/and frequency event \((P^*_{vf})\) is calculated as

\[
P^*_{vf} = \frac{3}{2} v_d i^*_{d-vf}.
\]

A phase-to-phase-to-ground fault is applied to the grid for analyzing the performance of the proposed control scheme. In this case study, the fault starts at \(t = 0.5\) s and causes a combined undervoltage and underfrequency event, as shown in Fig. 6. The positive-sequence voltage at the PCC drops to \(V = 0.7\) p.u. and the frequency to \(f = 49.7\) Hz, which both exceed the thresholds defined by the grid codes. It should be noted that in this case study, the grid is modeled as an ideal voltage source since the main goal of this case study was to verify the operation of the proposed scheme. Therefore, the frequency drop was modeled as a step reduction on the frequency, and it is estimated by the grid codes. As a result, the grid is considered in a fault mode, and the proposed control scheme is activated. Prior to the fault, the FESS operates in normal mode, in which the active power is set to \(P = 200\) W (discharging) and reactive power to \(Q = 0\) VAr. It should be pointed out that the active \((P)\) and reactive \((Q)\) power are calculated through the full \(dq\) equations as in (27) in order to achieve accurate calculation during transient events.

\[
\begin{bmatrix}
P \\
Q
\end{bmatrix} = \frac{3}{2} \begin{bmatrix}
v_d \\
-v_q
\end{bmatrix} \begin{bmatrix}
i^*_d \\
i^*_q
\end{bmatrix}.
\]

The reference current angle \(\theta^*_v\) during voltage support is calculated based on the grid impedance \(X/R\) ratio, as defined in (7), and the reference current angle \(\theta^*_f\) during frequency support is \(\theta^*_f = 0^\circ\), since reactive power prior to the fault is set to \(Q = 0\) VAr. According to the proposed voltage–frequency support scheme, the normalized voltage deviation is calculated as \(\Delta V_{pu} = 0.3\), and the normalized frequency deviation as \(\Delta f_{pu} = 0.1\); therefore, the voltage support is prioritized according to the sharing constant \(k_s\). As can be seen in Fig. 6, the FESS current increases to support both events, while the rated current of the GSC is respected \((I_n = 4.5\) A\) to ensure safe operation of the FESS. It should be noted that the GSC injects perfectly balanced currents even in case of unbalanced faults due to the enhanced performance by the DSRF current controller. As can be seen, the active power increases more than its steady-state value due to the contribution from the virtual inertia control loop that acts based on the RoCoF. Therefore, the FESS response can improve the maximum RoCoF, the frequency nadir, and also the voltage of the LVDG.
Fig. 7 demonstrates the active and reactive power generation of the FESS for the proposed and conventional (i.e., existing grid codes) control schemes under various scenarios. For a fair comparison, the same parameters have been used for both the proposed and conventional schemes. The response of the FESS for a frequency drop of 1 Hz at \( t = 0.5 \) s is shown in Fig. 7(a). In this scenario, the proposed support scheme shows superior performance in terms of frequency stability, since the active power increases faster due to the addition of the virtual inertia control. It should be noted that this faster rate of increase on active power can improve significantly the RoCoF and can increase the frequency nadir of the grid. Once the contribution from the virtual inertia control is eliminated (i.e., \( \frac{df}{dt} = 0 \)), the active power generation of the proposed scheme is the same with the conventional scheme since the same droop constants have been used.

Fig. 7(b) illustrates the response of the storage system under a voltage sag (\( V = 0.5 \) p.u.) applied at \( t = 0.5 \) s. As can be seen, using the conventional scheme, the full capacity of the inverter is utilized for the provision of reactive power. In this case, any active power generation should be reduced to zero to respect the current limits of the inverter. On the other hand, the proposed control scheme provides optimal voltage support by regulating both active and reactive power, which maximize the voltage conditions within LVDGs.

The storage system response to a combined voltage–frequency event (\( V = 0.7 \) p.u. and \( f = 49.6 \) Hz) applied at \( t = 0.5 \) s is shown in Fig. 7(c). At \( t = 0.6 \) s, the voltage sag is cleared; as a result, the voltage returns to its nominal value. For \( 0.5 \leq t \geq 0.6 \) s, the proposed scheme provides better support for the voltage and frequency due to the improved voltage control for distribution grid, the additional virtual inertia control loop, and the fair compensation scheme among the two types of support.

Fig. 8. Schematic diagram of the experimental setup.

Furthermore, when the voltage sag is cleared (i.e., voltage returns into the deadband zone), the conventional scheme remains in fault-ride-through mode for additional 500 ms according to the grid codes; as a result, the prefault active power is maintained, and frequency support cannot be provided. In this case, the frequency support will be activated after the 500 ms. The proposed solution prioritizes the frequency support once the voltage returns into the deadband zone; hence, significant improvements can be achieved in terms of frequency stability.

V. EXPERIMENTAL EVALUATION

An experimental setup has been developed to validate the performance of the proposed voltage–frequency support scheme, as shown in Fig. 8. A three-phase 5-kVA SEMIKRON Semiteach (B6U+E1C1F+B6C1) has been used as the GSC, and its associated controller has been developed with a dSPACE DS-1104 DSP board with sampling and switching frequency of 3.45 kHz. A dc power supply (ELEKTRO-AUTOMATIC) has been utilized to emulate the flywheel among the MSC or a chemical battery storage unit. The inverter has been connected through an \( LC \) filter and an inductance into a programmable ac source (California Instrument 2253iX), which has been used to emulate the grid. In addition, a 3-kVA three-phase load has been connected in parallel with the ac source to absorb the power from the inverter in order to avoid power fed back into the ac source since the ac source can only support two-quadrant operation. The current rating of the three-phase converter was limited to 4.5-A peak to ensure that the ac source will never absorb energy. Furthermore, a 5-kVA Y/D transformer has been utilized to ensure grid isolation. The parameters of the experimental setup are depicted in Table I.

Fig. 9 demonstrates the operation of the GSC under both balanced and unbalanced conditions. First, the programmable ac source was used to emulate a balanced three-phase fault, as shown in Fig. 9(a). In this case, the frequency was reduced from 50 to 49.5 Hz, and the voltage from 230 to 161 V. The storage unit was producing 200 W and 0 VAr during normal operation, as shown in Fig. 9(c). According to the fault characteristics, the sharing constant was 0.65, and as a result, the voltage support is prioritized. The voltage support scheme was activated first due to its faster dynamics, and then, frequency support was enabled few milliseconds later. Once both schemes were triggered, active and reactive powers were adjusted to 490 W and 440 VAr, respectively, to support both events. The implementation of virtual inertia control has provided an additional increase in the active power during the initial stage of the underfrequency event.
that can help with the reduction of the RoCoF. The peak current in the steady state is 3.12 A, which is in line with the proposed coordination scheme, while the current ratings of the inverter are respected.

Thereafter, a phase-to-phase fault combined with an underfrequency event was emulated, as shown in Fig. 9(d). The prefault conditions of the inverter were the same as in the previous case study. The voltage at phases $A$ and $B$ is reduced from 230 to 172 V and the grid frequency from 50 to 49.7 Hz; as a result, the sharing constant was calculated as $k_s = 0.71$. Once the proposed coordinated scheme was activated, the active power was changed to 300 W and the reactive power to $255 \, \text{VAR}$, as shown in Fig. 9(f). Although the inverter initially injects unbalanced currents due to the unbalanced voltage sag, the DSRF current controller gradually eliminates the unbalanced currents, and therefore, only the positive-sequence voltage was supported.

VI. IMPACT OF THE PROPOSED SCHEME ON THE GRID STABILITY

The impact of the proposed solution on the grid operation was evaluated in a realistic LVDG. For this reason, a four-wire LVDG was modeled in MATLAB/Simulink, as shown in Fig. 10, containing several loads, distributed generation (e.g., photovoltaics), and FESS. The medium-voltage (MV) grid was modeled using the sixth-order model of a synchronous generator with 500-kVA capacity and equipped with a droop-based governor and an ACS5A exciter to be able to investigate the dynamic change on frequency [35]. This change in frequency is proportionally related to the imbalance between the generation and load and can be approximated as

$$\frac{df}{dt} = \frac{P_G - P_L}{2H_S f_n}$$

(28)

where $P_G$ and $P_L$ represent the total active power generation and demand, respectively. The utilization of the dynamic model of the synchronous generator allows us to investigate the RoCoF behavior of the system, which according to (28) is affected by the inertia constant, the rating of the synchronous machine, and the power imbalance. The governor is responsible to stabilize the grid frequency to a new operating point, while the exciter tries to regulate the grid voltage at its nominal value. The governor response is activated after the inertia response of the synchronous generator and, as a result, is not affecting the RoCoF behavior of the system. The synchronous machine inertia coefficient ($H_S$), the governor droop coefficient ($R_{gov}$), the time constant of the governor ($T_G$), and the time constant of the inlet volume ($T_{CH}$) are listed in Table I.

For the analysis, a three-phase fault was applied at the MV feeder of the LVDG at $t = 10 \, \text{s}$, as shown in Fig. 10. Due to the fault, the circuit breaker (CB) was tripped to clear the fault after 300 ms. As a result, the substations 2 to $N$ are disconnected leading to a power imbalance of 100 kVA, due to the loss of distributed generation connected to the corresponding substations. Due to the fault, the positive-sequence PCC voltage was reduced to 0.43 p.u. and the grid frequency to 49.3 Hz from 1 p.u. and 50 Hz, respectively. Prior to the fault, the FESS generation was $P_o = 1 \, \text{kW}$, and the total demand of the whole distribution grid was $P_L = 300 \, \text{kW}$. Three cases are considered in the analysis: I) one FESS with 20-kVA capacity (4% of synchronous generator capacity); II) 3xFESS with 20 kVA each (12% of synchronous generator capacity); and III) one FESS with weak grid conditions.
Three different scenarios were considered for the three case studies (I, II, and III) to evaluate the impact of the proposed strategy: (a) no support by the FESS (i.e., FESS remains interconnected and maintains the prior the fault operating conditions); (b) conventional support by the FESS according to grid codes; and (c) proposed coordinated voltage and frequency support. It should be pointed out that the same voltage and frequency droop coefficients are used for all the scenarios.

Fig. 11 demonstrates the frequency, RoCoF, and grid voltage according to different scenarios for Case I (20-kV A FESS). The baseline scenario is considered the one that no support was provided by the FESS (Scenario A). When the conventional support scheme was applied (Scenario B), the inverter initially utilizes its full capacity for providing reactive current injection \( i^* = I_n \) for supporting the voltage. According to the grid codes, once the voltage returns in the deadband zone, voltage support should continue to be provided for 500 ms, and then, frequency support can be activated. As a result, frequency stability is considerably affected. The proposed coordination of both voltage and frequency support (Scenario C) provides superior performance, since it dynamically supports both events according to the fault characteristics. For this case study, the steady-state value of the sharing coefficient during the fault was dynamically set to \( k_s = 0.72 \), prioritizing voltage support. However, once the fault was cleared by the CB and voltage returned into the deadband zone, the sharing constant was dynamically changed to zero for providing maximum support to the frequency. Furthermore, as can be seen from Fig. 11, the proposed scheme contributes to a faster frequency recovery.

Table II demonstrates the key performance indicators for voltage and frequency stability for the case study presented above. As can be seen, the maximum frequency deviation without the proposed method is 0.962 Hz. In contrast, when the proposed coordinated voltage and frequency support scheme is activated, the maximum frequency deviation is limited to 0.868 Hz. Therefore, the maximum frequency deviation is decreased by 9.77% when the proposed scheme is implemented. Moreover, another key parameter for the frequency stability, the maximum RoCoF, is reduced from 0.468 to 0.426 Hz/s by the proposed coordinated scheme indicating a 8.97% improvement compared to the existing grid regulations. Finally, the minimum voltage when the conventional schemes are implemented is 0.431 p.u., while in case the proposed coordinated scheme is
used, it is limited to 0.451 p.u., indicating 4.64% improvement. Table II also demonstrates case study II with 3xFESS of 20 kVA. As it was expected, the key performance parameters indicate a greater improvement, and as a result, the higher exploitation of these devices in the distribution grid can positively impact the grid stability.

Case study III was considered to demonstrate the performance of the proposed scheme in case of a weak grid (with lower inertia). For this reason, the inertia of the synchronous generator was reduced by 40% to represent weak grid conditions, and the same three-phase fault was applied. The simulation results are shown in Fig. 12. As can be seen, the lower inertia of the synchronous generator leads to greater oscillations on the frequency, lower frequency nadir, and greater RoCoF. Using the proposed coordinated voltage and frequency support scheme, the frequency nadir is limited from 48.84 to 48.97 Hz, the maximum RoCoF is improved from 0.64 to 0.57 Hz/s, and the magnitude of the positive-sequence voltage is increased from 0.431 to 0.451 p.u. The key performance indicators from case study III are also shown in Table II. As can be seen, the proposed control scheme indicates significant improvements on the voltage and frequency stability of weak grids.

VII. CONCLUSION

A coordinated voltage–frequency support scheme for storage systems connected to LVDGs is proposed. The solution utilizes the knowledge of the grid impedance for the development of a tailor-made voltage support scheme that is able to maximize the voltage conditions within the LVDG. Virtual inertia control is also implemented to emulate the inherent characteristics of synchronous generators and improve the frequency stability. Finally, a coordination scheme is developed to ensure fair compensation between voltage and frequency support. The proposed coordinated control scheme demonstrates significant benefits compared with the conventional grid codes. Simulation and experimental investigations were carried out to validate the performance of the proposed support scheme and to demonstrate the impact in realistic distribution grids.

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Anastasis Charalambous (Student Member, IEEE) received the B.Sc. degree in electrical engineering from the University of Cyprus, Nicosia, Cyprus, in 2015, and the M.Sc. degree in wind energy systems from the University of Strathclyde, Glasgow, U.K., in 2016. He is currently working toward the Ph.D. degree with the Department of Electrical and Computer Engineering, University of Cyprus. He is also a Researcher with the KIOS Research and Innovation Center of Excellence, University of Cyprus. His research interests include renewable energy systems, storage systems, control for power electronics, and provision of ancillary services.

Lenos Hadjidemetriou (Member, IEEE) received the Diploma degree in electrical and computer engineering from the National Technical University of Athens, Athens, Greece, in 2010, and the Ph.D. degree in electrical engineering from the University of Cyprus, Nicosia, Cyprus, in 2016. He is currently a Research Lecturer with the KIOS Research and Innovation Center of Excellence, University of Cyprus. He has authored or coauthored more than 75 papers in scientific journals and international conference proceedings. He has extensive experience on managing research projects in the area of smart grids, and he has developed three advanced research laboratories in the University of Cyprus premises. His research interests include renewable energy systems, energy storage systems, control of power electronics, ancillary services, smart grids, and microgrids. Dr. Hadjidemetriou is a member of the Cyprus Technical Chamber. He volunteered as a reviewer to several IEEE Transactions and Conferences and received the Best Paper Award in the power quality session at the 2013 IEEE Industrial Electronics Society Conference.

Elias Kyriakides (Senior Member, IEEE) received the B.Sc. degree from the Illinois Institute of Technology, Chicago, IL, USA, in 2000, and the M.Sc. and Ph.D. degrees from Arizona State University, Tempe, AZ, USA, in 2001 and 2003, respectively, all in electrical engineering. He was an Associate Professor with the Department of Electrical and Computer Engineering and a Founding Member of the KIOS Research and Innovation Center of Excellence, University of Cyprus, Nicosia, Cyprus. His research interests include wide-area monitoring and control of power systems, the optimization of power system operation techniques, and the integration of renewable energy sources. Dr. Kyriakides served as the Action Chair of the ESF-COST Action IC0806 “Intelligent Monitoring, Control, and Security of Critical Infrastructure Systems” from 2009 to 2013. He was an Associate Editor for the IEEE SYSTEMS JOURNAL and an Editor for the IEEE TRANSACTIONS ON SUSTAINABLE ENERGY.

Marios M. Polycarpou (Fellow, IEEE) received the B.A. degree in computer science and the B.Sc. in electrical engineering from Rice University, Houston, TX, USA, in 1987, and the M.S. and Ph.D. degrees in electrical engineering from the University of Southern California, Los Angeles, CA, USA, in 1989 and 1992, respectively.

He is currently a Professor of Electrical and Computer Engineering and the Director of the KIOS Research and Innovation Center of Excellence, University of Cyprus, Nicosia, Cyprus. He is also a founding member of the Cyprus Academy of Sciences, Letters, and Arts. His teaching and research interests include intelligent systems and networks, adaptive and learning control systems, fault diagnosis, machine learning, and critical infrastructure systems. He has authored or coauthored more than 350 articles in refereed journals, edited books, and refereed conference proceedings, and coauthored seven books. He is also the holder of six patents.

Prof. Polycarpou received the 2016 IEEE Neural Networks Pioneer Award and the 2014 Best Paper Award for the journal Building and Environment (Elsevier). He was the President of the IEEE Computational Intelligence Society from 2012 to 2013, the President of the European Control Association from 2017 to 2019, and the Editor-in-Chief of the IEEE TRANSACTIONS ON NEURAL NETWORKS AND LEARNING SYSTEMS from 2004 to 2010. He is an Honorary Professor of the Imperial College London and a Fellow of the International Federation of Automatic Control. His research work has been funded by several agencies and industry in Europe and the USA, including the prestigious European Research Council (ERC) Advanced Grant, the ERC Synergy Grant, and the EU Teaming Project.