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Implementing Load-Side Operating Energy Reserves to Improve System Frequency Control Amid the Expansion of Distributed Generation

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ABSTRACT

Eskom, South Africa's national power utility, is transitioning from centralised, large-scale electricity coal generation to a more distributed, small-scale inverter-based renewable generation to reduce greenhouse gas emissions. This shift poses operational challenges, particularly in maintaining power system frequency stability, which relies on real-time balancing of supply and demand. Traditionally, frequency stability has depended on accurate load forecasts, sufficient generation capacity, and energy reserves from large generators to handle disturbances. However, as the number of large generators decreases, energy reserves will also reduce, potentially compromising frequency stability. This paper introduces the concept of integrating small-scale distributed generators to enhance both primary and secondary frequency control. By actively monitoring and managing these inverter-based generators, while accounting for phase balancing and network congestion, the proposed system seeks to improve grid stability, minimise reliance on large generators, and mitigate the risk of secondary frequency drops within an unmanaged inverter-based network (i.e. the high rate of change of frequency (RoCoF) may lead to inverter trips).

1 | Introduction

In a power system, maintaining stability requires generated power to match consumed power in real-time. Maintaining this balance depends on precise load forecasting and dependable generation dispatch, which are both challenging. Energy reserves, known as ancillary services, are used to address mismatches. Traditionally, these services are provided by big generators and are easily managed. Under normal conditions, large generators operate below total capacity, reserving the remaining capacity for short-term energy imbalances. This study explores an alternative approach to Ancillary Services using small-scale distributed renewable energy generators and storage systems, a need driven by efforts to lower greenhouse gas emissions by replacing coal plants. Eskom has begun decommissioning older coal plants, but this shift poses challenges for maintaining frequency stability (i.e. real-time balancing of generated and consumed energy). The decommissioning of large generators has a dual impact on the power system. It not only reduces the available base load supply, which is crucial for meeting consistent energy demand, but also diminishes the energy reserves traditionally provided by these generators in real time. These reserves are essential for maintaining system stability and addressing short-term power imbalances, making their loss a significant challenge for grid reliability

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and resilience. For example, faults such as generator trips can disrupt the balance of supply and demand by suddenly reducing available power, in such cases, other connected generators must compensate through energy reserve services to stabilise the system. As coal plants (large generators) are retired, the grid's energy reserves diminish, making it increasingly necessary for distributed renewable generators to provide energy reserves and actively maintain frequency stability. To achieve a comparable Net Capacity Factor (NCF) [1] to that of a single coal plant, a substantial deployment of distributed generation units, particularly photovoltaic (PV) systems as studied here, is required. This study highlights the challenges and requirements for distributed renewables to contribute effectively to frequency stability and ancillary services traditionally provided by large-scale generators. Figure 1 illustrates the photovoltaic (PV) generation profiles for both summer and winter, showing the seasonal variations in energy production under clear sky conditions. The summer profile demonstrates peak energy generation due to extended daylight hours and high solar irradiance. In contrast, the winter profile indicates substantially lower energy production due to shorter daylight hours and a lower solar angle, resulting in decreased irradiance. These profiles emphasise the seasonal variability in PV generation, with maximum energy output in summer and minimum output in winter.

Designing for worst-case winter conditions, solar energy output can be divided into three key time intervals:

1. **Between 07:00 and 11:00**: Solar energy generation during this period is estimated to be approximately $2X$, where X represents a baseline unit of energy output. This estimation is derived using the triangle and rectangle approximation method, as shown in Figure 2. This approach allows for a simplified yet effective calculation of solar energy generation by dividing the energy profile into geometrical shapes, with the rectangle representing periods of steady generation and the triangle capturing gradual increases or decreases in output over time. This method approximates the total energy generated during the specified interval by the area under each shape.
2. **Between 11:00 and 13:00**: Solar energy output remains steady at approximately $2X$ during this interval.
3. **Between 13:00 and 17:00**: Finally, solar energy production is approximately $2X$ during the last interval.

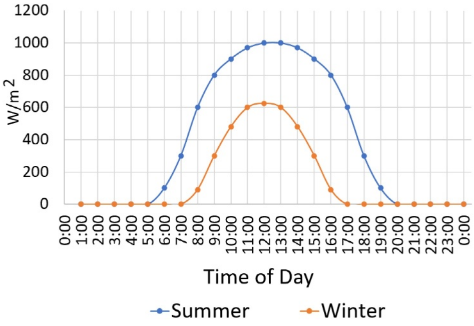

FIGURE 1 | PV generation profiles for summer and winter under clear sky conditions [2].

In summary, the energy generated from a PV plant over 24 h can be calculated as decribed by Equation (1):

$$\text{Total Energy Output} = 2X + 2X + 2X = 6X. \tag{1}$$

Therefore,

$$\text{NCF} = \frac{\text{Actual Energy Output over a Period}}{\text{Maximum Energy Output over the Same Period}} \times 100\% \tag{2}$$

$$\text{NCF} = \frac{6\text{X}}{24\text{X}} \times 100\% \tag{3}$$

$$\text{NCF} = 25\% \tag{4}$$

A combination of solar plants and storage systems is essential to ensure consistent power generation throughout the day in the worst-case winter scenario. Specifically, a minimum of one solar plant, supplemented by three solar plants with storage capabilities, would be required to achieve a total energy of 24X; this is sufficient to meet energy demands even during non-sunlight hours and similar to that of the coal power station. Therefore, the Total Daily Energy of PV System is decribed by Equation (5):

$$\text{Total Daily Energy of PV System} = 1 \times 6X + 3 \times 6X \tag{5}$$

This configuration suggests that a single coal plant producing X amount of energy could be effectively replaced by a combination of at least one standard PV plant and three PV plants equipped with storage, enabling consistent energy output throughout the day comparable to that of a coal plant. Thus, replacing a typical 3600 MW coal plant with a PV setup equivalent in NCF would necessitate approximately 144–180 PV plants of 100 MW each, accounting for additional units to address cloud cover and efficiency losses. With PV's NCF around 25% (as obtained from Equations (2) to (4) achieving an NCF comparable to a coal plant requires significant PV generation and storage system scaling. The increase in generating units complicates ancillary service management, as energy reserves previously provided by a single coal power station will need to be distributed across 180 different PV plants in the future. The study examines a scenario with optimal conditions, specifically a clear sky. However, scenarios involving high cloud cover would necessitate significantly larger installations to maintain energy reliability.

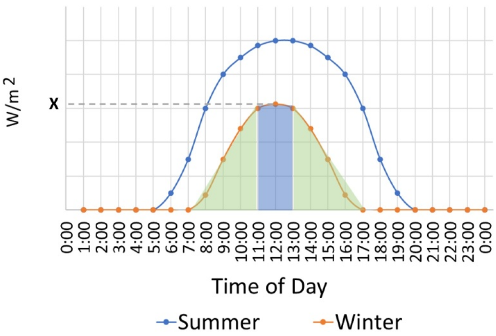

FIGURE 2 | PV energy generation estimation [2].

This shift requires a new strategy for managing ancillary services with multiple providers. Compounding this challenge, renewable energy generator sizes may range from 1 kW to 100 MW, depending on their connection points within the distribution network. Additionally, the South African government's initiative to accelerate renewable energy growth by raising the threshold to 100 MW for private generation plants now requiring only registration with the National Electricity Regulator of South Africa (NERSA) without a licence [3], adds to the complexity. This makes managing ancillary services more complex than the current system, which relies on fewer power stations.

Beyond technical challenges, this issue has significant economic implications. An unstable power system leads to increased power outages, widespread supply disruptions, and substantial financial losses, often quantified through the Cost of Unserved Energy (COUE) [4, 5] and Customer Interruption Cost (CIC) surveys. According to refs. [6, 7], in South Africa, the recent (between 2018 and 2023) recurring load shedding is primarily caused by generator unavailability due to maintenance issues resulting in insufficient Ancillary Services (energy reserves). This reduces utility revenues and disrupts productivity across various economic sectors. For example, a 24-h factory faces severe disruptions may struggle to recover lost production, while a standard-shift factory may adjusts schedules to mitigate production losses. Nonetheless, all businesses experience financial burdens, including reduced output, equipment damage, and higher costs for backup power. According to Erero [7], in South Africa, the National Energy Regulator (NERSA) has set the Cost of Unserved Energy (COUE) benchmark at R101.73 per kilowatt-hour (kWh), providing a standard measure for the economic impact of unserved energy. When the frequency of load shedding and the magnitude of energy interruptions are high, it is worthwhile to further evaluate the feasibility of implementing the strategy proposed in this paper to determine its actual benefits under real-world conditions. According to Erero [7], South Africa experienced its highest level of load-shedding in 2020, resulting in an estimated economic loss of R825 billion, primarily due to the inability to effectively manage generation fleet maintenance. If the transition to renewable energy is not carefully planned and executed, considering the strategies proposed in this article, the country could face similar economic setbacks in the future. Furthermore, during extensive load shedding, inverter-based resources may simultaneously switch to charging mode when power is restored, causing a sudden demand surge. The centralised control system proposed in this paper mitigates this issue by coordinating inverter operations to prevent grid strain and maintain stability during recovery. This underscores the importance of diligent planning, proactive infrastructure investments, and the integration of reliable energy solutions to ensure a stable and sustainable energy transition. The South African Grid Code limits the participation of small renewable energy generators in Ancillary Services [8] and the literature review has identified several notable gaps in the utilisation of distributed energy resources for providing Ancillary Services (more details in Section 2):

- **Limited Integration of Small-Scale Distributed Generation:** While substantial research discusses the integration of distributed generation, there is limited focus on the comprehensive monitoring and control of diverse small-scale generators to support critical functions such as ramp-up, ramp-down, and frequency control. This lack of focus constrains utilities' ability to reduce dependency on large-scale ancillary service providers.
- **Underutilisation of Small-Scale Generation for Frequency Control:** Research often neglects the coordination of small-scale generators through monitoring and centralised control to carry out primary and secondary frequency control. Utilising these generators more effectively could improve system frequency stability and decrease dependency on bulk supply generators for frequency support.
- **Ancillary Services from Distributed Renewable Energy To Manage High Energy Variability:** The literature seldom explores the potential of small-scale distributed generation and storage systems to provide ancillary services, which could help manage renewable energy variability and reduce the need for reserves from large generators.

This paper highlights the potential consequences for power system frequency stability associated with decommissioning coal power stations without adequately planning for ancillary services through new, distributed energy resources. This study introduces an innovative approach to addressing the challenges of unregulated distributed generation and energy storage systems in low-voltage networks, focussing on power system stability. Unlike traditional methods, which mainly target bulk generation, this research advocates for active collaboration between utilities and end-users across a wide area. The study aims to improve energy reserves for frequency control and stability while maintaining phase balance throughout the system by implementing real-time monitoring and control of distributed customer generation and storage systems. It emphasises integrating alternative energy sources to deliver essential services, such as frequency control, ramping capabilities, and energy reserves, facilitating a stable transition within the power grid.

1.1 | Contribution of the Study

The contribution of this study is to advocate for integrating currently unregulated distributed generators to strengthen the primary and secondary functions of system frequency control, thereby enhancing power system stability and reducing reliance on load shedding as energy reserves from large generators diminish in future networks. Additionally, the frequency drop risk due to the uncontrolled disconnection of distributed inverter-based generators during system frequency events of high RoCoF in networks dominated by inverter-based distributed generation should be reduced by adopting the proposed controller. This proposed controller systematically monitors and manages many small-scale (including single-phase) distributed generators to respond to short-term energy demands triggered by system frequency events. This proposal stands out from other research by focussing on real-time centralised monitoring and control. It considers several critical factors: the available battery capacity, the accessible local loads, the phase connection of the inverter, and phase balancing requirements, which are fundamental since most small-scale generators operate on a single phase. By addressing these elements, the proposal aims to optimise the responsiveness and efficiency of frequency control within a network of distributed resources, enhancing system stability and reliability. In addition, taking decisive action in this regard would facilitate the gradual development of skills and the establishment of frameworks at a manageable pace. Furthermore, the substantial increase in distributed renewable energy sources, such as wind and solar, results in significant fluctuations in net load, leading to a shortage of short-term generation ramping capacity. The management of ramping capacity is an ongoing development within the electricity market. As proposed in this paper, monitoring and controlling customer inverter-based generators can effectively address the challenges posed by large load fluctuations and ramping capability management by leveraging customer battery storage facilities during periods of constraint, thereby reducing the cost of network interruptions.

1.2 | Structure of the Paper

This paper is organised as follows: Section 2 reviews the relevant literature, identifying the gaps and opportunities that this study seeks to address or leverage. Section 3 outlines the methodology and research steps undertaken. Section 4 discusses the theoretical framework applicable to this study. Section 4.1 examines the power system network layout, while Section 4.2 reports on the current Eskom Ancillary Service, focussing on the use of large generators (mainly coal-powered) and hydro-pump storage schemes. Section 5 discusses the development of the proof-of-concept system. Finally, Section 7 presents the conclusions and offers recommendations.

2 | Related Work

This article proposes central monitoring and control of many distributed single phase energy resources to enhance frequency stability and short-term energy reserves. A lot of research has already been conducted in this specific area, however the literature review suggests a lack of publications regarding the delivery of ancillary services (energy reserves to support power system stability) via distributed inverter-based single phase generation and storage systems.

2.1 | Definition of Various Operating Energy Reserves

Operating energy reserves are critical for maintaining system stability by mitigating errors in load forecasting and responding to system contingencies, such as unanticipated generation or load disruptions. The increasing integration of intermittent renewable energy sources further amplifies supply-demand imbalances, requiring greater reliance on ancillary services. As the presence of large generators diminishes (due to transition from coal to renewable energy), and their role in providing reserves declines, a new approach to continuous energy regulation becomes necessary. The planning and utilisation of these reserves vary across utilities due to differences in operational strategies, available resources, and grid requirements. This variability highlights the necessity of tailored approaches or standardisation to energy reserve management to ensure reliability and efficiency.

Countries differ significantly in the definitions and classifications of ancillary services, leading to diverse interpretations of energy reserves. Despite these differences, the universal objective remains consistent: ancillary services are fundamental for maintaining frequency and voltage stability within power systems. According to Heffner [9], ancillary services can be classified into six key categories:

1. **Continuous Regulation:** Ensures real-time tracking of minute-to-minute power imbalances, maintaining grid responsiveness.
2. **Energy Imbalance Management:** Balances hourly variations in energy supply and demand, particularly important for systems with high renewable energy penetration.
3. **Instantaneous Contingency Reserve:** Addresses rapid fluctuations resulting from major incidents, such as the sudden loss of generation.
4. **Replacement Reserve:** Provides backup during outages to restore lost generation and maintain reliability.
5. **Voltage Support:** Supplies reactive power to stabilise voltage levels across the grid.
6. **Black Start:** Facilitates grid re-energisation following a blackout, ensuring system resilience.

This paper builds on these foundational concepts, introducing a novel framework for integrating small-scale distributed resources, including inverter-based generation, to enhance ancillary service provision and address modern power system challenges. In contrast, ref. [10, 11] categorise ancillary services into three broad groups: frequency control, voltage control, and system restoration. While this classification offers a simplified framework, it raises several critical considerations. Firstly, frequency control encompasses primary, secondary, and tertiary levels, each targeting specific operational time scales. Consolidating these into a single category risks overlooking the distinct challenges and requirements of each control layer, particularly under complex grid conditions. Secondly, voltage control, which relies on reactive power, involves diverse resources, such as distributed generation and capacitor banks. The generalised framework may underrepresent the operational nuances of managing reactive power, especially in distribution systems where resource variability is high. Lastly, system restoration (or 'black start') is not merely an energy-balancing function but a specialised process requiring dedicated assets and procedures to re-energise the grid independently. Grouping this function with other services risks underestimating its critical role in grid resilience during emergencies. Recent studies [10, 11] provide a baseline understanding, the growing complexity of modern grids necessitates more detailed classifications. For instance, ref. [12] highlights replacement reserves as essential for tertiary control or Manual Frequency Restoration, a critical process for resetting automated frequency systems. The significant variation in ancillary service definitions across countries complicates the establishment of a standardised implementation framework. Recognising this challenge, this study prioritises customising solutions to address South Africa's unique power system requirements, focussing on tailored approaches that leverage local resources and grid dynamics.

2.2 | Provision of Energy Reserves Through Distributed Energy Resources

The involvement of end-user customers and Distributed Energy Resources (DER) in providing ancillary services is a well-established concept. Studies such as [9, 13] highlight examples from various countries where end-users actively participate in ancillary services, demonstrating the potential for decentralised energy management. This decentralisation enables utilities to leverage smaller, distributed assets to improve grid stability. However, no existing evidence supports the active use of small-scale, inverter-based generation for primary and secondary frequency control via a centralised control system that also accounts for phase balancing and network congestion, as proposed in this paper. The proposed strategy introduces a seamless transition, where the inverter's local load shifts from grid supply to local inverter storage during system frequency event, optimising resource utilisation and reducing short-term demand. Other research involves utilising controllable loads for ancillary services [14] in scenarios where communication infrastructure constraints prevent the use of a centralised controller. While this approach offers a practical solution in low-connectivity environments, it significantly differs from the strategy proposed in this paper. The proposed controller leverages robust communication infrastructure and real-time information from multiple inverters to make precise, dynamic decisions. This reliance on real-time data enhances the controller's ability to respond effectively to rapid system changes, enabling more accurate and reliable frequency control. Moreover, the absence of robust communication systems in some frameworks limits their scalability and responsiveness, especially under complex grid conditions. The novelty of this paper lies in its focus on overcoming these challenges by integrating distributed inverter-based DER with a centralised controller that utilises real-time data. Furthermore, the reliance on real-time communication infrastructure ensures that the proposed framework can adapt dynamically to system fluctuations, providing a more resilient and responsive solution for modern power grids. Recent research, such as [15, 16], has concentrated significantly on identifying economic gaps and opportunities for Distributed Energy Resources (DER) across various countries. These studies aim to explore how DER can integrate into existing energy markets and provide cost-effective solutions, often emphasising the economic incentives for both utilities and private energy suppliers. While this is a valuable perspective, it differs from the primary focus of this paper, which addresses the operational and technical aspects of DER integration for maintaining frequency stability and enhancing energy reserves. Similarly, another area of research highlights the modelling and validation of DER systems. For example, ref. [17] presents a comprehensive study on the modelling and validation of four types of DER resources. The research offers detailed insights into the operational capabilities of these resources. However, this line of inquiry also differs from the goals of this paper, which aims to advance the practical application of DER. Although the aforementioned studies contribute significantly to understanding DER from economic and modelling perspectives, they often overlook critical operational challenges, such as the real-time deployment of inverter-based DER into existing control frameworks taking into account phase balancing and network capacity constraint. This paper proposes an energy deployment strategy at the local load of the inverter while ensuring phase balancing of the local network. This gap is especially relevant given the increasing penetration of renewable energy sources, which demands enhanced grid responsiveness and stability. The novelty of this paper lies in its focus on leveraging on customer DER and customer inverter local loads, to actively support primary and secondary system frequency control as illustrated through laboratory experiment. By addressing operational intricacies, such as the network congestion and phase balancing, this paper offers a more comprehensive solution to the challenges posed by modern energy systems. In addition, in South Africa, the active participation of low-voltage end-users and DER in ancillary services remains largely unexplored. The studies in refs. [18, 19] investigate the use of Heating, Ventilation, and Air Conditioning (HVAC) systems for providing ancillary services by switching the HVAC systems ON and OFF to stabilise the grid's supply-demand balance amidst significant fluctuations caused by intermittent renewable energy sources. This approach differs from the proposed strategy which shift the supply from grid to inverter local storage seamlessly instead of removing the load altogether. This difference highlights a gap in the continuous oversight and management of distributed generation resources, thereby underscoring the relevance of the proposed system in this paper. In ref. [20], the authors investigate frequency control mechanisms within power systems with a significant presence of inverter-based resources. Their findings underscore the critical necessity for fast frequency response (FFR) resources to maintain system stability amid the rapid power supply and demand fluctuations due to intermittent renewable energy. While the authors introduce an advanced local converter control system to enhance frequency response, their approach fundamentally differs from the methodology proposed in this study. Instead, this study emphasises the control of clusters or groups of inverters, seeking to optimise the collective response of multiple distributed generation units rather than focussing solely on individual converter systems. This distinction highlights the innovative aspect of the proposed method and its potential for achieving more coordinated and effective frequency regulation in the context of increasing reliance on inverter-based resources in the energy landscape. In ref. [21], the authors propose an innovative framework tailored for power systems with low inertia. In these grids, sudden generation losses can cause sharp frequency declines, emphasising the critical need for rapid frequency response mechanisms. Such sharp declines can trigger the disconnection of inverter-based generation units due to their sensitivity to high rates of change of frequency (RoCoF), potentially exacerbating system instability. The controller proposed in this study addresses these limitations, offering a robust solution to mitigate these challenges effectively.

2.3 | Systems for Enhancing Distributed Energy

In another publication [22], the authors examine a pilot SmartNet initiative that introduces several supplementary service models designed to guide future electricity systems and associated energy markets in maintaining energy balance for supply reliability and security, including:

1. Central Market Model–the Transmission System Operator (TSO) manages the energy balance for all connected Transmission and Distribution networks resources without involvement of the Distribution System Operator;
2. Local Market Model–the Distribution System Operator (DSO) manages energy balance for all resources connected to it; and
3. Shared Balancing Model–the TSO and DSO jointly bear the responsibility in a coordinated fashion.

The SmartNet project offers a comprehensive understanding of energy management challenges stemming from the increased penetration of renewable energy, characterised by its dynamic and less controllable nature. It primarily focuses on designing TSO-DSO architectures for real-time markets and identifying Information and Communication Technology (ICT) requirements to address the growing demand for managing distributed generation effectively. Leveraging platforms such as SmartNet can significantly bolster the implementation of the solution proposed in this paper. The authors of ref. [23] highlight that the substantial rise in renewable energy sources, such as wind and solar, leads to significant fluctuations in net load, creating a shortage of short-term generation ramping capacity. The system to manage ramping capacity is currently being developed within the electricity market. In addition to primary and secondary system frequency control, the monitoring and control of inverter-based generators, as proposed in this paper, can effectively address the challenges of large load fluctuations and ramping capability management by leveraging customer battery storage facilities during periods of constraints.

2.4 | Optimisation of Distributed Energy

The authors of ref. [24] introduce a robust and cost-effective day-ahead scheduling strategy for delivering distributed ancillary services, aimed at minimising the overall cost of this service; this strategy can be utilised to improve the proposed control system. Finally, the proposed approach requires precise measurements and the correct assignment of inverters to the appropriate phases to ensure system balance during the control process. The method for automatically identifying the phase connection of a residential single-phase customer using a smart metre, as introduced in ref. [25], can also be applied with similar outcomes achievable through inverter measurements. Accurately determining the phase connections of individual customers is essential for achieving a balanced three-phase system at an aggregated level, supporting the proposed control strategy.

2.5 | Summary

In summary, significant evidence suggests the proposed approach is innovative. Prior research supports the implementation of this unique solution, highlighting the potential of utilising inverter-based distributed generation to improve the primary and secondary control of system frequency. The existing literature indicates the need to effectively integrate advanced inverter technologies into existing power systems, addressing current challenges associated with frequency stability and network capacity. Moreover, the convergence of research findings underscores the relevance of this approach in the context of an evolving energy landscape, where the increasing penetration of renewable energy sources necessitates more flexible and responsive control strategies. By leveraging the insights from prior studies, this proposed solution fills a critical gap in current methodologies and paves the way for further advancements in power system management and reliability.

3 | Methodology

This study employs a comprehensive and integrated approach, combining three complementary methodologies: real generator trip event analysis, simulation modelling, and laboratory experimentation. Each of these methods contributes unique insights into system behaviour, providing a multi-dimensional view of the research problem and helping to confirm the viability of the proposed solution in both theoretical and practical terms. The methodology framework is shown in Figure 3.

This methodology integrates three complementary approaches: real-event analysis, simulation modelling, and laboratory experimentation to develop a robust, reliable conceptual frequency control system for power grids with inverter-based resources:

1. **Real-Event Analysis**: This foundational step establishes a performance baseline by analysing actual generator trip events, providing insights into real-world system dynamics and refining simulation models to better represent actual grid behaviour under various operational conditions.
2. **Simulation Modelling**: Building on real-event insights, simulation models are fine-tuned to predict system responses under various hypothetical scenarios, including rare and extreme events that might challenge system stability. This controlled simulation environment allows for

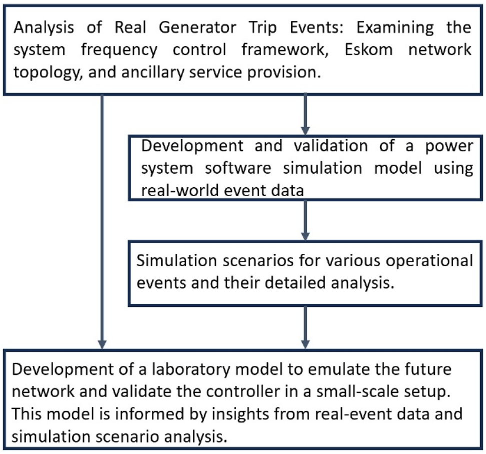

FIGURE 3 | Methodology for controller development.

testing and adaptation, ensuring the model can accurately simulate complex grid operations.

3. **Laboratory Experimentation**: Conducting trials in a controlled lab setup that emulates real-world conditions bridges theory with practical application. This phase verifies the solution's feasibility, accounting for hardware constraints and response times, and provides confidence in the system's readiness for deployment in operational conditions.

Together, these methods enable a comprehensive understanding of system frequency control challenges. Cross-validation among these approaches enhances the reliability of the results, with each method corroborating and reinforcing the findings of the others. This layered methodology ensures that the proposed solution is rigorously tested across theoretical, simulated, and practical perspectives, equipping it to address frequency stability in modern power systems effectively.

4 | Theoretical Framework of System Frequency Control, Eskom Network Topology and Provision of Energy Reserves

This section presents the traditional theoretical framework for system stability with the main focus on system frequency control as highlighted in Figure 4. The framework is based on bulk supply generator control [26] and the introduction of a new concept of load-side control using inverter-based supply to enhance frequency regulation in the short term. Currently, electricity is supplied by interconnected synchronous generators operating at 50 Hz.

The steady-state speed of each generator is governed by the following Equation (6):

$$n_s = \frac{120 \cdot f}{P} \tag{6}$$

where: n_s is the synchronous speed (in RPM), f is the grid frequency (in Hz), and P is the number of generator poles. The electrical power output of each generator contributing to the system's load demand is determined by the following Equation (7) [27, 28]:

$$P_{e_i} = \frac{E_i V_i}{X_{s_i}} \sin\delta_i \tag{7}$$

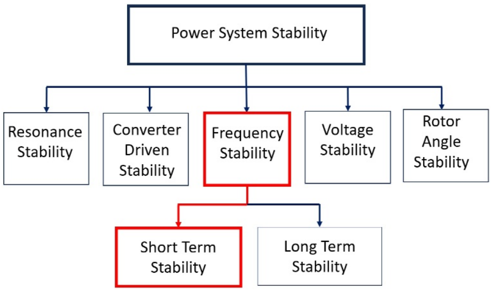

FIGURE 4 | Power system analysis framework [26].

where for each generator i: P_{e_i} is the electrical power output, E_i is the internally generated voltage (induced EMF), V_i is the terminal voltage (grid voltage), X_{s_i} is the synchronous reactance, and δ_i is the power angle.

During steady state, mechanical power input should be equal to electrical power output plus losses as given by the following Equation (8):

$$P_{m_i} = P_{e_i} + P_{\text{losses}_i} \tag{8}$$

where for each generator i: P_{m_i} is the mechanical power input, and P_{losses_i} represents generator losses (friction, windage, and electrical).

When connected to the grid, the generator's speed is synchronised with the grid frequency while supporting load demand. However, various factors can disrupt power flow, such as fluctuations in total generation input due to faults or changes in load demand. The swing Equation (9) describes the dynamic behaviour of a synchronous generator in response to such disturbances [29]:

$$J_i \frac{d^2\delta_i}{dt^2} + D_i \frac{d\delta_i}{dt} = P_{m_i} - \frac{E_i V_i}{X_{s_i}} \sin\delta_i \tag{9}$$

where for each generator i: J_i is the moment of inertia of the rotor (in kg·m^2), δ_i is the rotor angle (in radians), D_i is the damping coefficient (in N·m·s), $\frac{d\delta_i}{dt}$ is the angular velocity deviation (in rad/s), and $\frac{d^2\delta_i}{dt^2}$ is the angular acceleration (in rad/s^2).

The swing equation for each generator thus describes how imbalances in power lead to changes in the rotor's speed, influencing the rotor angle δ_i and the overall system frequency stability.

In a control area, system frequency is the same for all generators and therefore a change in system frequency experienced by individual generators is described by Equation (10) which sums the power deviation contributions from each generator.

$$\Delta f = \sum_{i=1}^{n} \frac{\left(P_{m_i} - P_{e_i}\right)}{2H_i} \tag{10}$$

where for each generator i: Δf is the frequency deviation (common to all generators), H_i is the inertia constant, and n represents the total number of generators.

Speed or frequency control is achieved in many ways as listed below:

1. **Excitation Control**: The excitation system for each generator i regulates the field current to control the internal voltage E_i and terminal voltage V_i. Maintaining constant voltage reduces the impact of voltage-dependent load changes, effectively decoupling frequency control from voltage fluctuations.

2. **Governor Control**: The governor for each generator i adjusts the mechanical power input P_{m_i} by regulating the prime mover's fuel or steam flow, ensuring rotor speed control and maintaining synchronism.

3. **Droop Control**: The droop control mechanism for each generator i adjusts the power output P_{e_i} based on frequency deviations Δf, enabling load sharing among generators as described by Equation (11):

$$\Delta P_i = -\frac{1}{R_i}\Delta f \tag{11}$$

   where R_i is the droop constant for generator i, and ΔP_i is the change in power output due to the frequency deviation Δf.

4. **Damping Mechanisms**: Damping to each generator's system helps mitigate oscillations in δ_i and ω_{r_i}, enhancing stability.
5. **Automatic Generation Control (AGC)**: AGC systems manage multiple governors simultaneously to align generation with load demand in response to frequency deviations.

This provides flexibility in load sharing among multiple generators and helps to balance the system more efficiently. As the number of generators increases, the operator can fine-tune the system by adjusting each generator's governor settings to achieve the desired power distribution.

Automatic generation control in a specific control area (i.e. a section of an interconnected power system i.e. responsible for supplying its own load) is described by Equation (12):

$$\Delta P_{\mathrm{AGC}} = B\Delta f \tag{12}$$

where: ΔP_{AGC} is the change in power output controlled by AGC, B is the frequency bias factor representing the sensitivity of the power system's response to changes in frequency, and is used in the control of frequency in power systems, and $\Delta f$is the frequency deviation.

The discussion of multiple control areas falls outside the scope of this paper. The theoretical framework discussed in this section focuses mainly on generator control. However, this paper emphasises load-side control mechanisms as an alternative approach to improve system frequency control, particularly in light of the expected decrease in the number of large generators in the future, which may pose challenges to traditional control methods.

$$P_L = \mathrm{Re}\left(\frac{Z_L}{Z_s + Z_L} \cdot P_{e_i}\right) \tag{13}$$

The total power delivered to the load P_L depends on both the electrical power at the generator terminal P_{e_i} and the impedance of the system Z_s (between the generator and the load) and the load Z_L. This relationship is illustrated in Equation (13). Consequently, any change in the load Z_L affects the generator's speed or frequency.

4.1 | Eskom Generation and Network Capacity Across Voltage Levels

Different voltage levels are designed to support specific power generation capacities. High-capacity generators (thousands of megawatts) are connected to high-voltage transmission systems for efficient long-distance power transfer, while smaller generators are integrated into distribution networks closer to consumption points. The increasing adoption of renewable energy decentralises power generation, complicating the management of numerous small units compared to fewer large ones.

In South Africa, the transmission system predominantly operates at 275 and 400 kV, sub-transmission at 88 and 132 kV, medium voltage at 11 and 22 kV, and low voltage at 230 V (single-phase) and 400 V (three-phase). Figure 5 shows the layout of South Africa's power system. Generation at or below sub-transmission voltages (levels 2, 3, and 4 in Figure 5) is most effective for local use, while generation at transmission voltages (level 1) supports wider utilisation. Frequency stability impacts the entire network, while distributed renewable generators are mainly designed for local supply, making the coordination of frequency control with distributed energy resources more challenging.

Eskom manages approximately 20 large-scale power stations with a combined capacity of 46,000 MW connected to the transmission network. Transmission System Operations (TSO) oversees bulk generation and transmission network management, ensuring sufficient ancillary services like active and reactive power reserves. Currently, distributors operating at sub-transmission and lower voltages focus on local network stability, with no generation control at the distribution level. However, increasing distributed generation necessitates a shift, requiring distribution operators to manage local generation and power flows. Proactive measures are essential to regulate inverter-based distributed generation to avoid unregulated energy generation, which can threaten supply security and necessitate excessive energy reserves. Uncontrolled inverter-based generation during frequency events can worsen frequency drops, increasing the risk of blackouts and load-shedding. Thus, consistent monitoring and control of inverter-based distributed generation is critical. The provision of energy reserves as an ancillary service, detailed in Section 4.2, becomes vital to maintaining system stability.

4.2 | Provision of Energy Reserves and Ancillary Services in Eskom

Eskom operates its power system at 50 Hz, supplying electricity at various voltage levels through its transmission and distribution networks. To maintain a stable system frequency of 50 Hz, power generation must balance consumption in real-time. Any deviation from this frequency indicates an imbalance, with

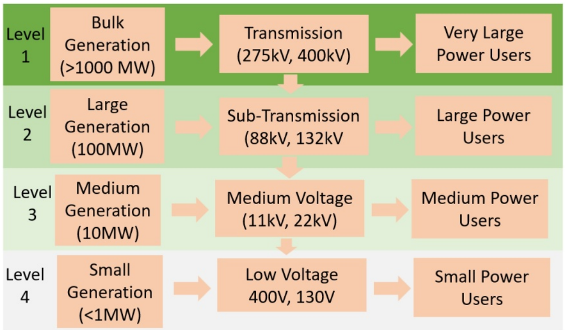

FIGURE 5 | Power system layout.

significant deviations risking damage to equipment such as generators, transformers and consumer devices [30–32]. Perfect balance is challenging due to factors such as limited control over usage, imperfect load forecasts, system disturbances, and unregulated energy production. To address this, Eskom employs ancillary services—energy reserves that ensure stability by compensating for active and reactive power imbalances. This paper focuses on active power reserves, critical for frequency stability. Ancillary service requirements depend on severe contingencies, such as the loss of a large generator or a cluster of smaller units. Remaining generators must compensate for power losses, a need that persists as distributed generation grows and large-scale generators decline.

4.2.1 | Energy Reserves for Frequency Control

System frequency stability requires continuous matching of power generation and consumption. To manage this, Eskom relies on energy reserves, particularly spinning reserves, to address sudden mismatches. Figure 6 illustrates how reserves support primary and secondary control, with tertiary control typically involving non-spinning reserves activated manually.

4.2.2 | Control Mechanisms

1. **System Inertia:** Resistance to frequency changes provided by the rotational mass of synchronous generators and rotating loads.
2. **Primary Control:** Automatic generator output adjustments using droop control to counteract frequency deviations:

$$P_{\text{droop}} = \begin{cases} 0 & \text{if } |f_{\text{n}} - f_{\text{act}}| \leq \text{DB} \\ \dfrac{K_{\text{droop}}}{f_{\text{n}}} \cdot \left(f_{\text{n}} - f_{\text{act}}\right) & \text{otherwise} \end{cases}$$

   where: P_{droop} is the power change, K_{droop} is the droop constant, f_{n} is the nominal frequency, and DB is the dead band.
3. **Secondary Control:** Automatic Generation Control (AGC) fine-tunes generator outputs based on sustained frequency deviations.

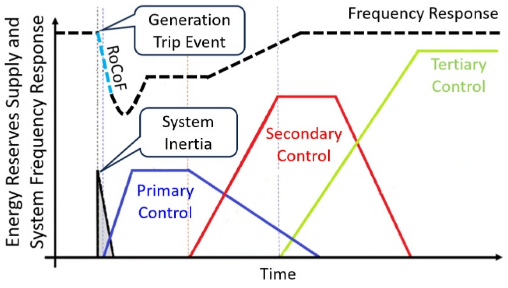

FIGURE 6 | System frequency response and energy reserve support after generation trip.

4. **Tertiary Control:** Manual operator interventions to adjust generator set-points for longer-term imbalances.

4.2.3 | Real Case of Eskom's Ancillary Services Provision

During a 900 MW generator trip, Eskom deployed both coal and hydro pump storage stations for frequency control. Figure 7 shows how a coal generator contributed 30 MW through droop control. Figure 8 illustrates how hydro pump storage units transitioned modes, adding 450 MW for primary control.

Hydro pump storage stations operate in three modes: Pump Mode (load operation), Synchronous Condenser Operation (voltage regulation), and Generation Mode (active power supply). Figure 9 outlines their control flowchart, showing how they adapt to restore frequency stability.

In total, 450 MW was sourced from hydro storage, with the remainder compensated by other generators, demonstrating the critical role of ancillary services in maintaining stability.

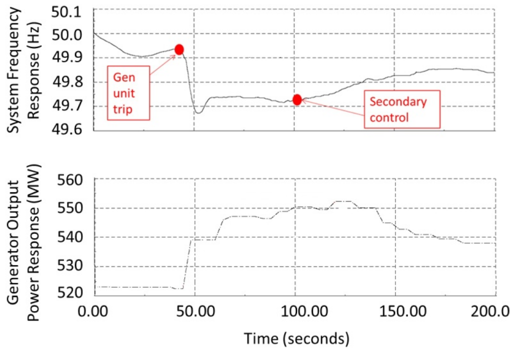

FIGURE 7 | System frequency response after 900 MW generator trip.

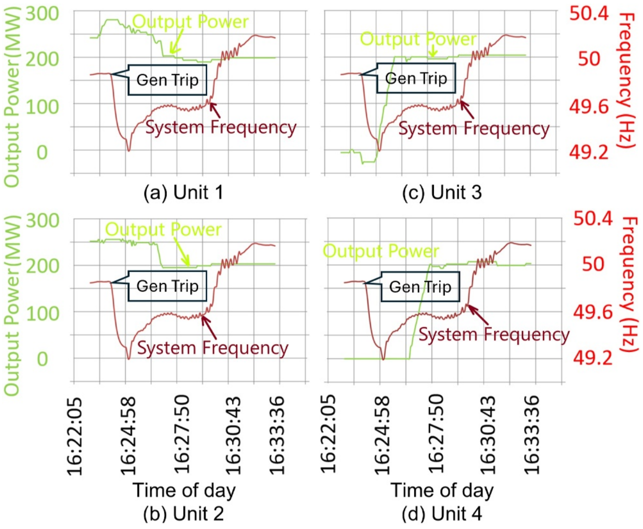

FIGURE 8 | Drakensberg units response after generator trip.

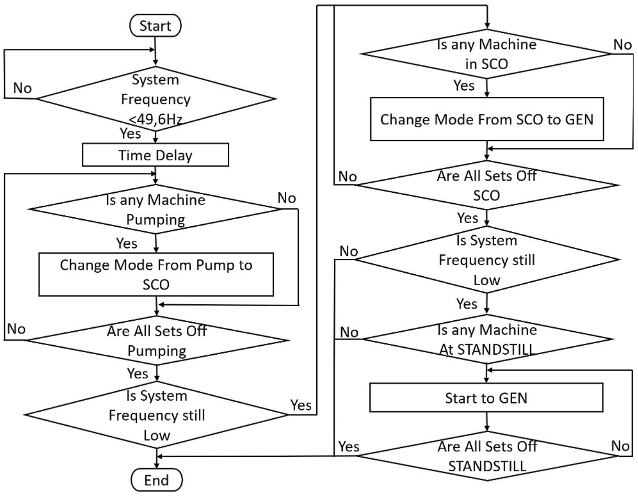

FIGURE 9 | Hydro pump storage station control flowchart.

5 | Proof of Concept

Two approaches are utilised to validate the proof of concept: Eskom power system simulation and laboratory testing.

5.1 | Eskom Power System Simulation

5.1.1 | Eskom Model Consideration

- The simulation model for the system frequency response took into consideration several crucial factors, including:
- 20 power stations with a combined output of 34,666 MW in 2023 reported on Eskom weekly;
- The largest generator in the system, which will be utilised for contingency analysis, has a capacity of 900 MW;
- Some loads are modelled to vary with voltage and frequency, while others remain constant in terms of power, with no dependency on voltage or frequency;
- There are no limitations within the network concerning the transmission of power from power stations to load centres; and
- Generators are configured with Automatic Voltage Regulator (AVR) and Governor Control mechanisms, but without Power System Stabilizers (PSS), which is deemed sufficient for the objectives of the study.

The study used a DigSilent Power Factory Model of the Eskom power system, developed as described in refs. [33–35], to replicate various load support mechanisms serving as ancillary services. The fundamental premise of this load support concept is rooted in the idea that integrating small-scale generation alongside associated battery storage can form a substantial energy reservoir capable of fulfiling Ancillary Service requirements as they emerge. This integration is achieved by organising customer inverters into manageable clusters. The control methodology entails coordinating the operations of these inverter clusters sequentially, leveraging principles similar to those applied in established hydro pump storage stations, as previously discussed. The determination of the size of these inverter clusters is based on the energy required to make a substantial contribution to dynamically controlling the system frequency. System frequency should comply with the South African grid code requirement which requires the system frequency to be with 49 and 51 Hz under normal operating condition. Furthermore, the governor control should be activated if the frequency drops below 49.85 Hz or surpasses 50.15 Hz. The dead band for governor control spans from 49.85 to 50.15 Hz.

The system generation is simulated to offer a collective support of 600 MW via governor control when load reduction assistance is not available. Each simulated generator output power mirrors that of an actual event as shown in Figure 10.

5.1.2 | Simulation Results of the Eskom System

Simulation results from various scenarios demonstrate an impact of load reduction when used as a frequency control measure, highlighting its positive effect on the required spinning reserves for primary control. The amount of load reduction directly influences the utilisation of spinning reserves from generators within the system. Figure 11a shows the system frequency response following a generator trip, comparing two scenarios: one with 600 MW of governing (generator spinning reserves) without load-side reduction support and another with 300 MW of enforced load-side reduction support. Notably, in the latter scenario, the generator's governing decreases by 100 MW compared to the former as shown in Figure 11b.

The assessment of the performance of primary control, known as instantaneous reserves (IR), is evaluated using the Average Maximum Sustained (AMS) power [36]:

$$AMS = 0.5\left(\frac{Actual_{\max}}{Target_{\max}} + \frac{Actual_{\mathrm{sus}}}{Target_{\mathrm{sus}}}\right) \tag{14}$$

where: AMS: Average of the maximum sustained; $Actual_{\max}$ is the maximum sent-out power over the initial 10 s; $Actual_{\mathrm{sus}}$ is the average sent-out power after 10 s up to 10 min; $Target_{\max}$ is the maximum contracted power over the initial 10 s; and $Target_{\mathrm{sus}}$ is the average contracted power after 10 s up to 10 min.

Figure 11c and 11d further illustrates Equation (14), showing the governor and frequency response following a generation loss, and demonstrating maximum power and sustained power. If the AMS performance (referenced to the requirement) falls below acceptable levels, the service provider incurs penalties in line with the service level agreement.

Furthermore, The model accounts for the reduction in system load due to the frequency dependency of loads, whereby they adjust to fluctuations in the AC power supply frequency. Various electrical loads exhibit differing degrees of sensitivity to frequency variations, particularly those comprising inductive components such as motors, transformers, and fluorescent lights. Changes in frequency modify the impedance of these inductive loads, thereby impacting their power consumption. This relationship is described by Equation (15):

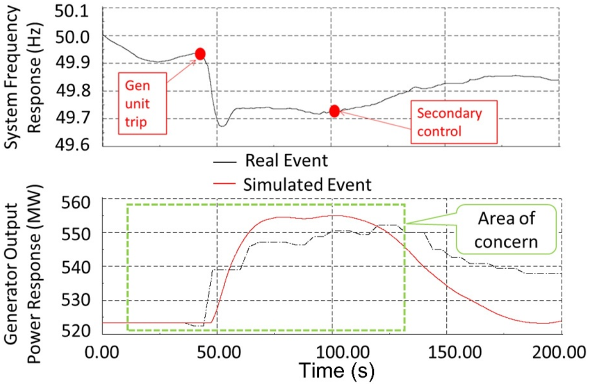

FIGURE 10 | Real generator trip event.

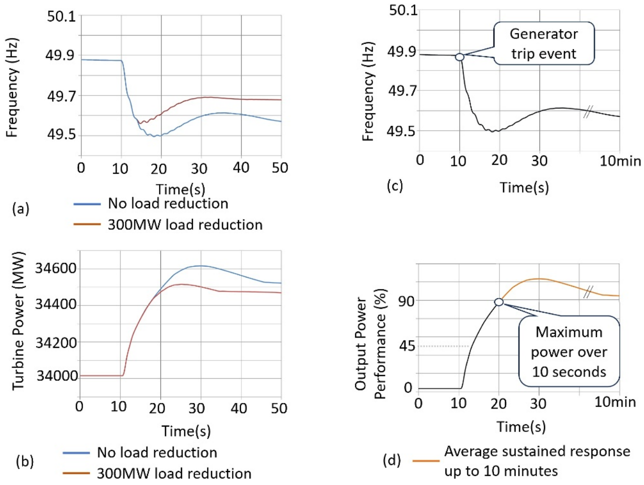

FIGURE 11 | System frequency response with load reduction support. (a) Simulated system frequency response following a generator trip at 10 s. (b) Simulated turbine power response following a generator trip at 10 s. (c) System frequency response requirement within 10 min. (d) Turbine power response requirement within 10 min.

$$Z_{\text{final}} = Z_{\text{initial}} \pm \Delta Z_f \tag{15}$$

where: Z_{final} is the final load impedance at the adjusted frequency; Z_{initial} is the initial load impedance at nominal frequency; and ΔZ_f is the change in impedance due to frequency variations, this term can be adjusted through inverter control by shifting the local load between the grid and the inverter supply to compensate for frequency fluctuations. In addition, according to refs. [37, 38], load behaviour is described by the following Equations (16) and (17):

$$P(V, f) = P_0 \left(\frac{V}{V_0}\right)^{\alpha} \left(\frac{f}{f_0}\right)^{\phi} \tag{16}$$

$$Q(V, f) = Q_0 \left(\frac{V}{V_0}\right)^{\beta} \left(\frac{f}{f_0}\right)^{\gamma} \tag{17}$$

where: P_0 is the real power before disturbance; Q_0 is the reactive power before disturbance; V_0 is the RMS voltage amplitude before disturbance; f_0 is the frequency before disturbance; V is the RMS voltage amplitude after disturbance; f is the frequency after disturbance; α is the partial derivative of real power with respect to voltage; ϕ is the partial derivative of real power with respect to frequency; β is the partial derivative of reactive power with respect to voltage; and γ is the partial derivative of reactive power with respect to frequency.

In addition, the simulation model accounts for certain loads that are unaffected by voltage or frequency variations, maintaining a constant power consumption irrespective of changes in frequency or voltage within specific thresholds. Loads managed by Variable Frequency Drives (VFDs), such as pumps or fans, are engineered to function at variable frequencies. However, these mechanisms require stable frequency regulation to maintain precise motor speeds and performance, and are referred to as constant power loads.

This study demonstrates a noteworthy advantage in managing loads to maintain system frequency. Load reduction support results in an improved frequency response and a reduced spinning reserves requirement. This is a scenario that represents future networks where spinning reserves from big generators are reduced.

5.2 | Laboratory Testing

A laboratory set-up with two generators and inverter system was constructed.

5.2.1 | Installation Specification

The set-up consisted of:

- Generator: $S = 6.5$ kVA, $X_s = 37.53\ \Omega$, $f = 50$ Hz, $V = 220/380$ V;
- Inverter per phase: $S = 1$ kVA per phase, AC Input Voltage $= 220$ V, DC input Voltage $= 12$ V DC; and
- Load per phase $= 55\ \Omega$.

5.2.2 | Laboratory Simulation Limitations

The following are the limitations of the laboratory test:

- The system does not have an AVR, voltage control is performed manually;
- There is no automatic speed control of the generator;
- The inertia of the system is negligibly small, therefore, the speed drops or increases instantly during system disturbances and
- The generator supplies an unbalanced load which has a negative effect on generator efficiency and vibration.

The main limitation of the experimental setup is its small scale compared to the envisioned full-scale implementation. Successful real-world deployment would require a robust communication infrastructure, which was beyond this study's scope but is essential for coordinating distributed resources and timely response, an area for future development. The absence of an AVR could pose a significant challenge in this test, primarily due to the voltage dependency of loads. As the generators are gradually loaded, they respond by reducing terminal voltage rather than adjusting speed or frequency. This situation contrasts with real network scenarios, where voltages typically remain constant across the system as a whole. Consequently, in a real system, the speed or frequency of the generators is influenced by changes in supply and demand. Therefore, the presence of a voltage regulator for the laboratory generator becomes essential for this exercise. The adjustment of the generator terminal voltage was manually conducted in this exercise. Initially, the system was operated without voltage regulation, and the findings indicate that the generator speed (and thus frequency) remains unaffected in the absence of terminal voltage regulation. The findings indicated that as the load demand rises, there is a concurrent decrease in voltage observed at the generator terminals, while the frequency or speed remains constant, and vice versa. While implementing voltage regulation to maintain a constant generator terminal voltage as the load demand increases, the result was a decrease in frequency, resembling the behaviour of a real network. To ensure both the generator terminal voltage and generator speed remain constant, both the field current and speed of the generator need to be regulated.

There are two primary methods to control the speed or frequency of the generator. Firstly, it can be achieved by adjusting the speed of the prime mover (using a DC motor and adjuting its field current in this case). Speed control can be attained through several iterations characterised by Equation (18):

$$f_{\text{new}} = f_{\text{old}} + K_p \cdot \left(f_{\text{set}} - f_{\text{old}}\right) + K_i \cdot \int \left(f_{\text{set}} - f_{\text{old}}\right) \cdot dt \qquad (18)$$

where: f_{new} is the new frequency set-point; f_{old} is the current frequency; f_{set} is the desired frequency set-point; K_p is the proportional gain; and K_i is the integral gain.

Secondly, it can be controlled by managing the load demand under constant generator terminal voltage. The load demand exhibits a direct proportionality to the speed of the generator under this condition of constant terminal voltage.

In this scenario, speed regulation is achieved by adjusting and controlling the load demand. The generator operates in parallel with loads connected via an inverter. The inverter batteries are consistently charged to maintain a capacity level above 80%. In case of a high demand leading to a frequency drop below a predetermined threshold, the inverter switches to local supply mode for a specified period (i.e., within primary control requirement), utilising the battery power instead of drawing from the grid. This action alleviates stress on the grid and restores the frequency to acceptable levels.

Table 1 presents the standard parameters of the inverter that are observable and useful for making decisions regarding load demand management.

In order to demonstrate the efficacy of using inverter parameters for load management, a simple algorithm was formulated as illustrated in the flowchart in Figure 12. The grid frequency is continually monitored, and adjustments are made to the inverter operational mode when the frequency surpasses the predetermined frequency threshold. The decision regarding which inverter to engage in frequency control depends on both the immediate load that can be swiftly disconnected from the system and the capacity of the battery to supply the load locally. Systems with higher battery capacity that can rapidly manage big local loads are better equipped to respond to frequency fluctuations, thereby reducing the risk of grid instability. In a large-scale system, it is possible to determine in advance the amount of load needed to alter the system frequency by a specific amount, such as 0.1 Hz. As a result, inverters can be strategically used to regulate the frequency to the desired level while maintaining phase balancing in real time.

The laboratory circuit diagram given in Figure 13 illustrates the parallel connection of the synchronous generators with the hybrid inverter, which then provides power to AC loads.

A hybrid inverter serves as an interface for integrating DC-generated solar power, utility network, battery storage, and a generator. The inverter measures various parameters that can be utilised to manage customer electricity usage. Additionally, the hybrid inverter can be controlled remotely via serial communication to execute specific control, monitoring, and set-up functions as and when required. The serial communication (of the inverter used in the laboratory) uses the Cyclic Redundancy Check (CRC) protocol, ensuring high data integrity through error checks. The inverter operates in two modes: line mode and battery mode. In line mode, it can function in a bypass mode, supplying power directly to the load from the generator or utility

TABLE 1 | Typical internal parameters of an inverter.

Inverter parameter	Unit	Inverter parameter	Unit
Grid voltage	V	Battery voltage	V
Grid frequency	Hz	Battery charging current	A
Output voltage	V	Battery capacity	%
Output frequency	Hz	Battery discharge current	A
Output reactive power	VAr	Inverter heat sink temp.	°C
Output active power	kW	PV input current	A
Output load percentage	%	PV input voltage	V

while simultaneously charging the battery using solar PV panels (if connected to the solar). In cases where solar PV panels are unavailable, the battery is charged from the generator or the utility grid. In battery mode, the load is supplied from solar PV, the battery, or both sources simultaneously. Also, in the absence of solar PV, the load can only receive power from the battery. In the laboratory experiment, the inverter on the DC side was connected to the battery, not to the solar PV.

The laboratory controller is designed using a Raspberry Pi which monitors frequency and command inverter to change mode of operation to battery when the frequency declines below the set threshold of 49.6 HZ thereby restoring the frequency to acceptable levels above 49 Hz. The Raspberry Pi is a compact computer with diverse applications that extend across various domains, such as home automation and robotics [39]. While the Raspberry Pi suffices for demonstrating the concept outlined in this paper, a more robust and efficient controller would be advisable for large real-world systems. The laboratory setup has limitations; the real system would be vastly larger, with millions of connections, and would present numerous operational challenges beyond the scope of this article.

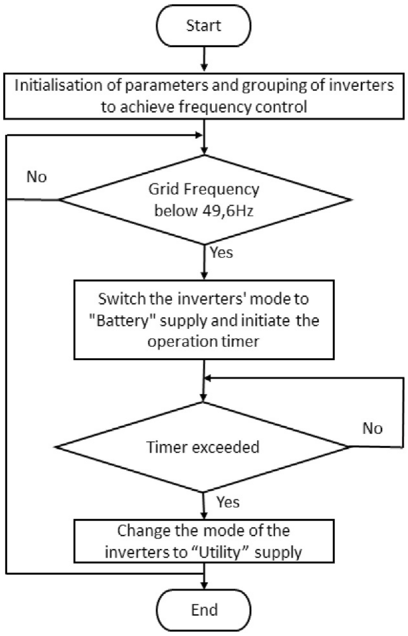

FIGURE 12 | Frequency control using load demand management through inverter.

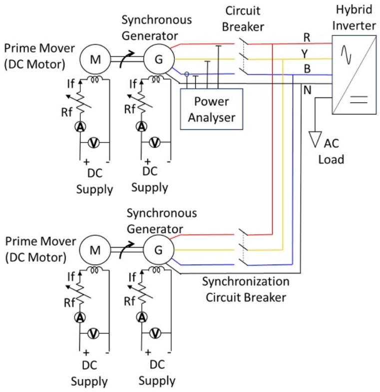

FIGURE 13 | Laboratory circuit diagram.

The total load was fed from two generators, and each phase had a demand of 4 A. One of the generators was then tripped and removed from the system while the remaining generator terminal voltage was maintained constant, which resulted in a drop in speed and hence frequency. The frequency was then restored by sequentially changing the mode of operation of each inverter from Grid Mode to Battery Mode resulting in a reduction in the demand of the generator as shown in Figure 14. The sequence of events is as follows:

1. At Interval 4, one generator was disconnected from the system, causing the remaining generator to experience a sharp drop in speed/frequency (an expected outcome in future networks with a limited number of synchronous generators and a high proportion of inverter-based generation).
2. At Interval 8, the first inverter reduced the load on the generator, stabilising the system and improving its speed.
3. By Interval 12, the second inverter shifted additional load from the generator to the local inverter supply, further improving the speed.
4. Finally, at Interval 16, the third inverter removed the remaining load, restoring the generator speed to its initial value.

This sequence illustrates how coordinated inverter control can effectively manage load distribution and stabilise generator speed in the future with inverter-dominant networks. The amount of load reduced from the remaining generator matches the output of the lost generator, thus restoring the speed to its original level through inverter control. The hybrid inverter has the capability to either supply the full load of the customer installation or solely power essential appliances. In a large system the loads connected to the inverter can be monitored to ensure that when a generator is lost, it is compensated by same amount of load reduction to restore system frequency at its initial value (i.e. before the generator trip).

As outlined in ref. [40], the computation of the average active power in an unbalanced system is derived from the following Equation (19):

$$P_{\mathrm{av}} = V_{\mathrm{a}} I_{\mathrm{a}} \cos(\phi_{\mathrm{a}}) + V_{\mathrm{b}} I_{\mathrm{b}} \cos(\phi_{\mathrm{b}}) + V_{\mathrm{c}} I_{\mathrm{c}} \cos(\phi_{\mathrm{c}}) \qquad (19)$$

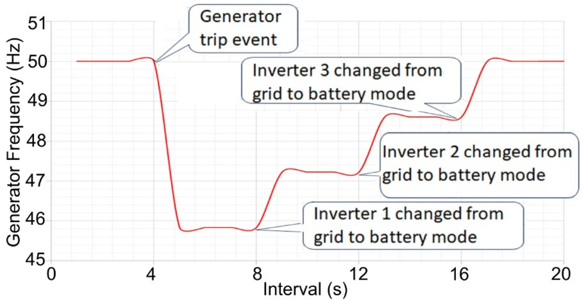

FIGURE 14 | Lab results of frequency control by reducing grid demand.

where: P_{av} is the average active power; V_a, V_b, V_c are the Phase A, B and C voltages; I_a, I_b, I_c are the Phase A, B and C currents; and $\cos(\phi_a)$, $\cos(\phi_b)$, $\cos(\phi_c)$ are the Phase A, B and C power factors.

Given the resistive nature of the loads, the power factor across all three phases in the laboratory is 1.

6 | Additional Optimisation Considerations for a Controller

The sizing of inverter clusters is dynamically determined based on the real-time information provided by each inverter, including the available stored energy in the system and the corresponding demand that can be quickly offset to decrease dependency on grid supply. This approach ensures that the inverter clusters are appropriately scaled to balance supply and demand effectively. The dynamic calculation considers real-time energy storage levels, expected power requirements, and grid conditions, enabling optimal utilisation of stored energy while maintaining grid stability. The system frequency must adhere to the South African Grid Code, which requires frequency to remain between 49 and 51 Hz under normal operating conditions. Additionally, governor control must activate if the frequency falls below 49.85 Hz or exceeds 50.15 Hz. The governor control deadband, set between 49.85 and 50.15 Hz, ensures precise frequency regulation within this range. The inverter cluster controller must operate within the parameters set by the governor control. A discrete Proportional Integral Derivative (PID) controller is proposed for managing the inverter clusters through the aggregation process. The control system diagram is shown in Figure 15.

In this diagram, the "Plant" represents the system being controlled, which reacts to the control signal, as described in Equation (20). In discrete-time, the control signal at the n-th sample is written as follows:

$$u[n] = K_p e[n] + K_i \sum_{k=0}^{n} e[k]\Delta t + K_d \frac{e[n] - e[n-1]}{\Delta t} \qquad (20)$$

where: $u[n]$ is the control output at the n-th sample, $e[n]$ is $r[n] - y[n]$, the error at the n-th sample, $r[n]$ is the reference signal (the desired power compensation of the system which can be set prior the system frequency event and considering other sources of energy reserves), $y[n]$ is the measured output (actual output compensated power), K_p, K_i, K_d are the proportional, integral, and derivative gains, respectively, Δt is the sampling period. Aggregated load profiles tend to remain stable over short durations, such as 1 minute, with minimal fluctuations. According to Proedrou [41], residential load models are typically sampled at rates ranging from 1 minute to 1 hour. Studies such as refs. [42, 43] indicate that high frequency sampling (around one minute) is necessary for small subsets of customers, while lower frequency sampling (approximately 60 min) suffices for larger groups of 40–60 customers. For the proposed controller, sampling intervals should range from seconds for primary frequency control to a few minutes for secondary frequency control. These intervals can be further optimised based on system requirements and the time delays inherent in the control system. This controller structure allows for precise tuning of the system's dynamic response, ensuring that frequency deviations are corrected swiftly while balancing three phases of the supply effectively. As the network expands with increasing integration of distributed energy resources, this flexible control strategy will enable seamless coordination between inverter clusters and centralised generation control, further enhancing the stability of the grid.

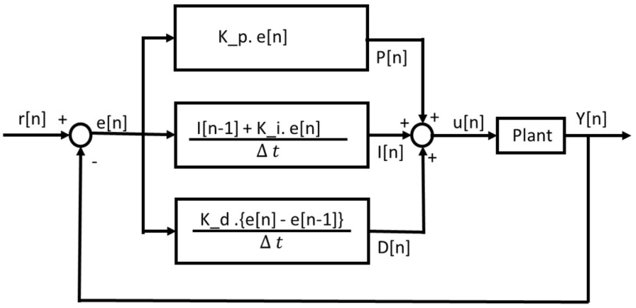

FIGURE 15 | Control system block diagram of inverter clusters.

7 | Conclusion

In future networks, the dependence on energy reserves from large generators is expected to decrease, necessitating alternative methods for providing energy reserves. The findings of this study highlight a significant benefit in the management of loads and customer energy storage facilities to improve system frequency stability through an inverter-based generation system. Supporting load reduction (through inverter monitoring and control) leads to improved frequency response and a reduced need for spinning reserves. The solution proposed in this study has the potential to provide energy reserves if implemented proactively before the system faces severe constraints. The technology necessary to implement the proposed solution is already available in the market and can be customised to realise the suggested approach. The primary hurdle in implementation arises from the lack of standardisation in inverter communication protocols, which vary between manufacturers. Thus, promoting standardisation in this area is crucial to facilitate the ease of implementation and communication among various devices within a grid. The proposed strategy is highly compatible with networks that primarily serve single-phase customers integrated with distributed generation. It effectively manages phase balancing and allows for strategic charging or discharging of battery storage as needed to address short-term generation constraints. This approach improves system flexibility and stability by dynamically adjusting energy storage resources in response to fluctuations in generation and demand, ensuring a balanced and reliable power supply. Although the proposed controller was not tested against other customer-side frequency control systems, its advantage lies in addressing phase balancing, a factor often overlooked in other customer-side strategies.

Author Contributions

Dumisani Mtolo: conceptualisation, design, data analysis and original draft preparation. **Rudiren Sarma:** supervision, technical support,

project administration, funding acquisition, review and editing. **David G. Dorrell:** guidance, technical expertise, strategic direction and manuscript review.

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Conflicts of Interest

The authors declare no conflicts of interest.

Data Availability Statement

Data supporting this study are available from the corresponding author upon request.

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Appendix A

Two laboratory synchronous generators provide the three-phase supply. The laboratory layout is shown in Figure A1.

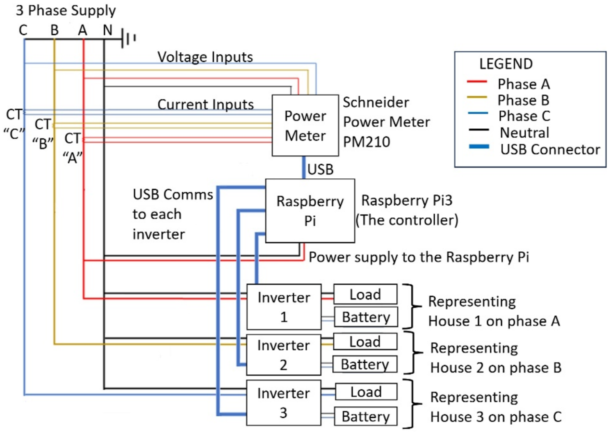

FIGURE A1 | Laboratory inverter connection layout.