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Input Admittance Shaping-based Active Islanding Detection Technique for Multi-inverter Microgrids

Ali Emadi, Javad Sadeh , and Reza Bakhshi-Jafarabadi , *Senior Member, IEEE*

Abstract—Deploying grid ancillary services through distributed energy resources (DERs) challenges islanding detection techniques (IDTs). Power regulations, for instance, may mitigate power mismatches in islanded microgrids, increasing the risk of undetected islands. Additionally, when the grid is connected, false islanding detection during low-voltage events can disrupt low-voltage ride-through (LVRT) operations. Existing IDTs that comply with these services and requirements often suffer from power quality degradation and limited scalability in multi-inverter systems. To address these gaps, this study proposes an active IDT using the DER's input admittance shaping within a narrow negative-sequence frequency band. The shaped admittance results in a negligible negative-sequence disturbance (NSD) injection during grid-connected operation while ensuring rapid and synchronized NSD jump after island formation in multi-inverter systems. Thus, islanding is detected when the rate of change of negative-sequence voltage at the DER terminal exceeds a preset threshold within a specified timeframe. Importantly, the proposed IDT does not affect the positive sequence component, avoiding conflict with ancillary services in grid-connected operations. Numerous simulations are conducted in PSCAD-EMTDC in accordance with the IEEE Std. 1547.1-2020 test procedure. The results demonstrate precise and rapid islanding detection in single- and multi-inverter scenarios, including zero/small power mismatches with DER's power regulations. In addition, the proposed IDT does not exhibit false tripping during low-voltage events, complying with LVRT requirements.

Index Terms—Ancillary services, distributed energy resource, input admittance, islanding detection technique, microgrid, multi-inverter, negative sequence.

I. INTRODUCTION

THE integration of distributed energy resources (DERs) into distribution networks is steadily increasing due to their techno-socio-economic-environmental benefits. Despite these advantages, the shift from centralized, predictable power generation to a decentralized, intermittent one has raised new control and protection concerns, such as unintentional islanding. This hazardous situation occurs when a microgrid becomes isolated from the upstream network but remains energized by a DER. It poses risks to unsuspecting repair personnel and

may damage utility equipment and consumer devices due to large frequency/voltage fluctuations. To mitigate these risks, DERs must detect islanding and cease power output within 2 seconds [1], [2]. Also, IEEE Std. 1547-2018 recommends an uninterrupted supply of critical loads after islanding detection by isolating the microgrid's circuit breaker (CB) and switching to a standalone control scheme [1].

Many researchers have delved into developing new islanding detection techniques (IDTs). The effectiveness of the proposed schemes is mainly evaluated based on criteria such as non-detection zone (NDZ), power quality (PQ) degradation, detection speed, and compatibility with multi-inverter systems. However, new grid codes have recently mandated ancillary services and low-voltage ride-through (LVRT) capabilities to address challenges associated with the increasing penetration of DERs into distribution networks. While these functions enhance voltage and frequency stability, they also complicate islanding detection. For instance, ancillary services such as active/reactive power regulations may reduce the post-islanding power mismatches, leading to undetected islanding operation. Moreover, IDTs must avoid false tripping during abnormal conditions such as low-voltage non-islanding events, and must comply with LVRT requirements [3]. As a result, IDTs that perform well under traditional evaluation criteria may become ineffective or incompatible when ancillary services and LVRT are in place.

IDTs are categorized into remote and local groups, as summarized in Table I. Remote methods utilize communication links to ensure fast, accurate detection compatible with ancillary services [4]. However, high costs and potential communication failures remain significant bottlenecks [5].

Local IDTs rely on DER-side measurements. Passive schemes detect islanding by monitoring deviations in point of common coupling (PCC) variables [4], [6]. While cost-effective and non-intrusive to PQ, they suffer from large NDZ when power mismatches are small. Furthermore, modern ride-through requirements widen permissible operation ranges, exacerbating the NDZ issues.

Specifically, passive negative-sequence schemes utilize the ratio of negative-sequence voltage (NSV) to current for impedance estimation [7], [8]. While effective for synchronous generators which naturally inject negative-sequence current (NSC), inverter-based DERs exhibit negligible NSC due to strict control. This results in a large NDZ in balanced or inverter-dominated grids. Additionally, criteria based solely on NSV magnitude are prone to false trips during unbalanced non-islanding events. Finally, intelligent IDTs enhance sensitivity but are often limited

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TABLE I
COMPARISON OF COMMERCIAL AND LITERATURE-BASED IDTs WITH THE PROPOSED ONE

Category	Methodology	NDZ	PQ Impact	Detection speed	Multi-Inverter	Ancillary services	Complexity	Comments
Remote	SCADA/PLCC/DTT PMU/ μ PMU	None	None	Fast	Good	Unaffected	High	Complex and costly
Passive	OUF/OUV	Large	None	Slow	Good	High	Low	Threshold setting is difficult
	ROCOF/ROCOV/PJD	Moderate	None	Moderate to Quick	Moderate	High		
	Harmonic detection	Moderate	None	Slow	Poor	Unaffected	Low	High sensitivity to harmonics
	Negative-sequence impedance/voltage	Moderate	None	Slow	Poor	Unaffected	Low	Limitations in inverter-based DERs and balanced networks
	Signal Processing /Machine Learning	Potentially none	None	Fast	Good	Moderate	High	Large training data needed
Local	Impedance measurement/RPV	Medium to Small	Moderate	Fast	Poor	Low	Low	Sensitive to noise and load transients
	Q-f Droop	Medium to Small	Low to moderate	Moderate	Moderate	High	Moderate	Requires coordinated slope settings
	AFD	Medium	High	Slow	Poor	Moderate	Low	THD and cancellation issues in multi-inverter
	SVS	Medium to Small	Low	Moderate	Good	Moderate	Moderate	Stability issues under weak grids
	SFS / SMS	Small	Low	Fast	Moderate	Moderate	Moderate	Out of synchronism issues in weak grids
	Harmonic/ inter-harmonic Injection	Small	Moderate	Moderate	Poor	Unaffected	Moderate	Sensitive to harmonic pollution
	Negative Sequence Injection	Small	Low to Moderate	Moderate to Fast	Poor	Unaffected	Moderate	False positives possible under natural grid unbalance
Hybrid	Passive + Active stage	Smaller than passive	Lower than active	Slow to Moderate	Depends on active	Moderate	High	Two stage decision process delays response
Active	Proposed input admittance shaping	Small	Very Low	Fast	Good	Unaffected	Moderate	---

by high computational complexity and the need for extensive training data [9].

Active IDTs inject a disturbance into a parameter of the DER's control system and then analyze the system's response. These disturbances accelerate the variation of PCC quantities after islanding, thereby reducing the NDZ and detection time. In hybrid schemes, an islanding condition is initially suspected by a passive technique and then confirmed by an active method. Although this two-stage decision processing avoids disturbance injection in normal operation, i.e., outperforms active IDTs from the PQ perspective, it takes longer to detect islanding [10], [11].

According to the reduced NDZ and detection time, active IDTs are widely used in commercial solar inverters [12]. Impedance measurement and reactive power variation (RPV) techniques inject a controlled disturbance into the DER's current or power reference. Then, the resulting impedance, voltage, or frequency variations observed at the DER terminal is compared against predefined thresholds [5], [13]. Classical techniques such as Sandia frequency shift (SFS), Sandia voltage shift (SVS), slip mode frequency shift (SMS), and active frequency drift (AFD) have been widely adopted in commercial inverters [12]. However, these methods introduce waveform distortion and degrade PQ during clearance time [14], [15], i.e., they fail to ensure a seamless transition to standalone operation [13]. Moreover, their performance deteriorates in multi-inverter microgrids, where injected disturbances from independent DERs may interfere destructively. A study in [16] has also shown that the activation of ancillary services and ride through requirements can increase detection time from 0.3 s to more than 1 s in multi-inverter systems.

The disturbance injection at frequencies other than the fundamental positive sequence component, such as harmonics [17], inter-harmonics [18], or negative sequence [19] has been established. A particular parameter, such as the impedance at the PCC, is then analyzed as the islanding detection indicator [20]. These IDTs barely affect the positive sequence voltage,

avoiding conflicts with ancillary services. However, all disturbances must be synchronized in microgrids with multiple DERs to avoid counteracting each other [17], [18], [21]. This synchronization is mainly realized by GPS, which increases the implementation cost. Also, this method requires information on phase shifts imposed by interface transformers. Others adopted phase synchronization using the fundamental voltage phase or zero crossing [22], which is less effective when the output power of different DERs is unequal [17].

The synchronization issue is addressed to some extent by the small AC-signal injection IDT [17]. This method injects a disturbance at the fourth harmonic and droop control and virtual impedance. Despite its effective islanding detection and compatibility with modern DER functions, continuous fourth-harmonic injection with a fixed amplitude degrades PQ during grid-connected (GC) operation.

Recently, the NSC injection-based IDTs have been presented in [23] and [24]. However, these methods use a fixed and continuous NSC injection which degrades the PQ of the output current. In [19], a feedback-based NSC injection approach was developed to mitigate PQ degradation. While this method demonstrates effective detection in a balanced, single-DER system, its performance has not been evaluated under unbalanced three-phase conditions or in multi-inverter environments.

To address PQ challenges, [22] and [25] utilize decaying injection triggered by passive criteria. While the envelope limits its distortion duration, every sequence inefficiently initiates at maximum amplitude regardless of event severity. Moreover, the reliance on passive triggers creates an inherent conflict between minimizing the NDZ and maintaining PQ. Compounding this issue, the detection thresholds in these studies are defined heuristically based on limited simulation scenarios without considering ancillary services rather than a rigorous analytical framework.

The performance of IDTs summarized in Table I are evaluated across key criteria: NDZ, PQ impact, detection speed,

multi-inverter support, compatibility with ancillary services and LVRT requirements, and implementation complexity [9], [26], [16]. This analysis reveals that while several methods offer compliance with modern grid requirements, there remains a lack of comprehensive solutions that simultaneously ensure PQ preservation, and seamless integration with multi-inverter systems.

This paper proposes a new active IDT utilizing a novel admittance shaping framework. The proposed technique establishes a closed-loop feedback mechanism where the injected NSC is determined by the product of a shaped admittance and the NSV at the DER terminal ($I_{NSC} = Y_{NSD} \cdot V_t^-$). This approach yields several fundamental benefits:

- *Compatibility with ancillary services:* The detection strategy operates in the negative-sequence frame, which is mathematically orthogonal to the positive-sequence control used for power regulations.
- *Adaptive injection profile:* The shaped admittance acts as a band-pass filter, restricting injection to specific target frequencies. Unlike fixed-peak schemes, the disturbance magnitude is proportional to the NSV step change. The injection reaches the saturation ceiling only during genuine islanding and rare severe events, while naturally scaling down during frequent transients to minimize distortion.
- *Rigorous analytical design:* Control parameters are derived using the Nyquist criterion to guarantee stability during grid connection ($|Y_{NSD} / Y_{Grid}| < 1$). Conversely, upon islanding, the ratio shifts to $|Y_{NSD} / Y_{load}| > 1$, deliberately driving the system to instability. This amplifies the NSV at the DER terminal, ensuring fast detection and eliminating the NDZ.
- *Communication-free synchronization:* By aligning the phase of Y_{NSD} at critical frequencies, the method ensures constructive interference across dispersed DERs.
- *Topology-independent detection logic:* Islanding is confirmed when the rate of change of the NSV exceeds a threshold for a specific duration. Crucially, both the threshold and time delay are derived analytically and are independent of the system topology and configuration.

The rest of the paper is organized as follows. Section II elaborates on the proposed method principles. Section III deals with the criteria for selecting the threshold settings. Section IV presents simulation results, a comparison with several active IDTs, and a discussion. The concluding remarks are finally provided in Section V.

II. PROPOSED ISLANDING DETECTION TECHNIQUE

A. System Configuration Under Study

The proposed IDT is presented in a multi-PV-based microgrid model, shown in Fig. 1. However, it can be easily adapted for other inverter-based DERs. Similar to [17], [27], and [28], all PV units are connected to a common PCC for simplification, neglecting the small line impedances in comparison to the loads [29]. The PV units are two-stage conversion systems with three-phase voltage source inverters (VSI) and LC-type output filters. The utility power system at the PCC is modeled as a voltage

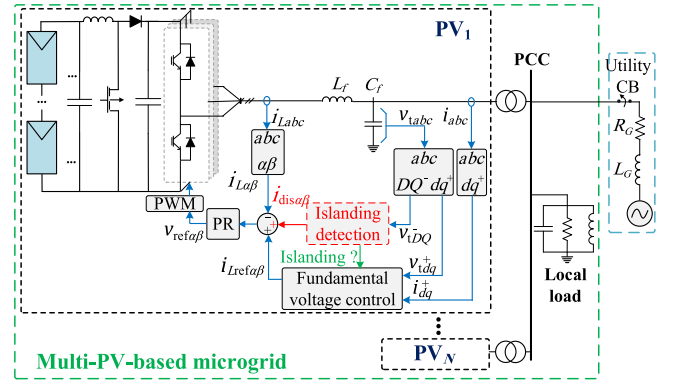


Fig. 1. Multi-PV-based microgrid model equipped with the proposed IDT.

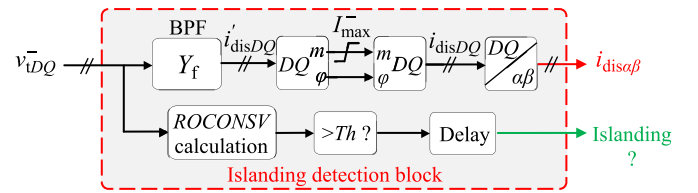


Fig. 2. Detailed structure of "islanding detection" block in Fig. 1.

source in series with an impedance. According to IEEE Std. 1547-2018 [1] and UL1741 [2], the local load is modeled by an RLC parallel branch. The microgrid becomes islanded when the main CB located at the PCC is opened.

The positive and negative sequence components of the voltage and current are extracted by the "abc/DQ/dq" blocks. The positive sequence components are fed into the "fundamental voltage control" block. The PV systems support various ancillary services in GC operation (e.g., active/reactive power control), seamless transfer, and voltage/frequency control in standalone through this block [30]. The output of this block determines the reference for the inductor current ($i_{Lref\alpha\beta}$).

B. Description of the Proposed Methodology

The proposed IDT is realized by adding an NSD ($i_{dis\alpha\beta}$) to the inductor current reference. The NSD is calculated by processing the extracted NSV at the PV terminal (v_{tDQ}^-). A proportional-resonant (PR) controller is employed to track the final reference current, i.e., $i_{Lref\alpha\beta} + i_{dis\alpha\beta}$.

The transfer function of the NSV extraction is defined as:

$$G_{NSV}(j\omega) = V_{tDQ}^-(j\omega) / V_{tDQ}(j\omega) \quad (1)$$

where V_{tDQ} represents the frequency-domain voltage at the PV terminal in DQ frame (negative sequence), and V_{tDQ}^- denotes the frequency-domain representation of v_{tDQ}^- .

Fig. 2 illustrates the detailed structure of the "islanding detection" block. The v_{tDQ}^- is passed through a band-pass filter (BPF) of Y_f . This BPF ensures that NSD injection occurs only within a narrow frequency band, so it does not affect other components. To enforce an NSD limit of I_{max}^- , the output of Y_f is converted to magnitude and phase by the "DQ/mφ" block,

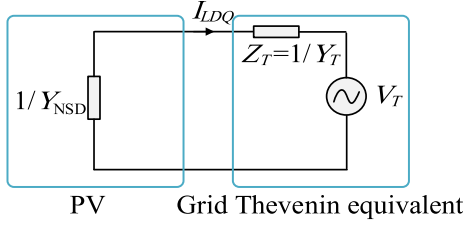


Fig. 3. Impedance model of Fig. 1 for single-PV system in GC mode.

where its magnitude is limited. It is then converted back to DQ values by the “ $m\phi/DQ$ ” block.

Considering the limiter saturation condition, the NSD in DQ frame in the frequency domain (I_{disDQ}) can be given as follows:

$$I_{disDQ}(j\omega) = \begin{cases} Y_f G_{NSV} V_{tDQ}(j\omega) & \text{limiter not saturated} \\ \frac{Y_f G_{NSV} V_{tDQ}(j\omega)}{|Y_f G_{NSV} V_{tDQ}(j\omega)|} I_{\max}^- & \text{limiter saturated} \end{cases} \quad (2)$$

The Bode plot of G_{NSV} exhibits negligible amplitudes around the positive sequence frequencies [31]. Hence, the disturbance given in (2) exclusively include negative-sequence components. Conversely, the “fundamental voltage control” block manages the positive sequence parameters. This ensures independent performance of the proposed IDT and the functions in the “fundamental voltage control” block including the ancillary services.

In GC operations, the limiter is unsaturated in sinusoidal steady-state due to stability of the control system. Considering the transfer function of current controller as G_c , the injected NSC into the inductor filter can be calculated as follows:

$$I_{LDQ}(j\omega) = G_c I_{disDQ}(j\omega) = \underbrace{G_c Y_f G_{NSV}}_{-Y_{NSD}} V_{tDQ}(j\omega) \quad (3)$$

Y_{NSD} in (3) and Fig. 3 is the shaped input admittance at the DER terminal by the proposed feedback. The negative sign in (3) before Y_{NSD} is because of the direction of the inductor current in Fig. 3. This figure illustrates the impedance model for a single-PV system.

The system is considered stable by the proposed feedback if the ratio of the input admittance (Y_{NSD}) to the grid admittance seen at the PV terminal (Y_T) meets the Nyquist stability criterion [32], i.e., the Nyquist plot of Y_{NSD}/Y_T does not encircle the point $(-1, 0)$ in the complex plane:

$$|Y_{NSD}(j\omega_{dis})/Y_T(j\omega_{dis})| \angle -Y_{NSD}(j\omega_{dis}) = \angle Y_T(j\omega_{dis}) < 1 \quad (4)$$

If the above condition holds, the Nyquist plot of the admittance ratio will cross the real axis at a value greater than -1, ensuring the system satisfies the Nyquist stability criterion. The grid admittance seen at the PV terminal (Y_T) changes when the operating condition shifts from GC mode to islanding one (the admittance of the capacitive output filter is neglected):

$$Y_T = \begin{cases} Y_G + Y_{RLC}; & \text{GC} \\ Y_{RLC}; & \text{Islanding} \end{cases} \quad (5)$$

where Y_G and Y_{RLC} represent the admittances of the utility grid and the local RLC load, respectively. $|Y_T|$ is significantly larger in GC operation due to the strength of the utility grid (i.e., great

Y_G). Y_{NSD} is designed so that (4) is satisfied during GC operation but violated after islanding. Hence, the VSI remains stable in GC and becomes unstable immediately after islanding. It is worth noting that the instability of the VSI occurs only within a narrow negative-sequence frequency band, with the disturbance amplitude limited to a maximum.

Due to stability during GC operation, any NSD triggered by non-islanding disturbances, such as capacitor switching or faults, decays to a steady-state value. According to Fig. 3, the steady-state inductor current caused by the proposed NSD can be determined as follows:

$$I_{LDQ}(j\omega_{dis}) = \frac{-V_T(j\omega_{dis})}{Z_T(j\omega_{dis}) + [1/Y_{NSD}(j\omega_{dis})]} \quad (6)$$

where, $V_T(j\omega_{dis})$ is the grid Thevenin voltage at the NSD frequency (ω_{dis}). Based on (6), I_{LDQ} would be negligible for small V_T or Y_{NSD} . Thus, $Y_{NSD}(j\omega_{dis})$ is designed in this work to possess eminently small values for all frequencies, except within a narrow range of negative-sequence inter-harmonics, denoted by $[-\omega_{\max}, -\omega_{\min}]$. The criteria for selecting $\omega_{\max}$ and $\omega_{\min}$ will be explained in Section III. Also, the grid voltage is expected to have negligible components within the selected inter-harmonic range under normal conditions, leading to small values of $V_T(j\omega_{dis})$. Hence, I_{LDQ} will approach zero for all frequency ranges in the steady-state of GC operation, i.e., it restores to zero during all non-islanding disturbances.

After islanding occurs, (4) is violated and the closed-loop system enters an unstable positive feedback condition, increasing the NSD amplitude until it reaches the $I_{\max}^-$ limit.

The injected NSD creates an oscillating NSV at the PV terminal (v_{tDQ}). The extracted NSV by the “ $abc/DQ/dq^+$ ” block (v_{tDQ}^-) can be expressed in the time domain as follows:

$$v_{tDQ}^-(t) = |V_{tDQ}^-| e^{j\omega_{dis}t} = |G_{NSV} V_{tDQ}| (\cos \omega_{dis}t + j \sin \omega_{dis}t) \quad (7)$$

The expression $V_{tDQ}^- = G_{NSV} V_{tDQ}$ is derived from (1).

Thus, an increase in $|v_{tDQ}^-|$ indicates an island formation. However, in addition to the proposed disturbance injection, the grid voltage may contain negative-sequence components during non-islanding events, such as short-circuit faults. During such events, v_{tDQ}^- initially rises to a certain level and then stabilizes at a steady-state value. In contrast, during islanding events, a continuous oscillating NSV at the PV terminal is observed, as described in (7). Therefore, this study uses the rate of change of NSV ($ROCONSV$) to distinguish between non-islanding and islanding events:

$$ROCONSV(t) = \frac{1}{T} |v_{tDQ\text{avg}}^-(t) - v_{tDQ\text{avg}}^-(t-T)| \quad (8)$$

where $v_{tDQ\text{avg}}^-$ is the average of v_{tDQ}^- over a time period T , calculated using a moving average filter (MAF). The MAF mitigates the effect of harmonics and noise on $ROCONSV$. Also, a larger T provides more attenuation but also slows down the decision process. In this study, T is accordingly set to $2\pi/\omega_0$, where ω_0 is the nominal angular frequency ($2\pi \times 60$ rad/s).

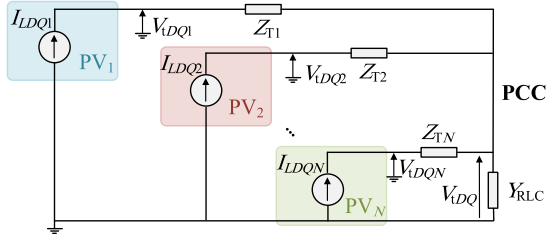


Fig. 4. Impedance model of Fig. 1 after islanding occurrence.

The post-islanding *ROCONSV* can be calculated as follows by placing (7) into (8) and some mathematical simplifications:

$$ROCONSV = |V_{tDQ}| \cdot \underbrace{|G_{NSV}(j\omega_{dis})| \cdot |\omega_{dis}| \frac{\sin^2(\pi\omega_{dis}/\omega_0)}{(\pi\omega_{dis}/\omega_0)^2}}_{F_{ROC}(\omega_{dis})} \quad (9)$$

When islanding occurs, *ROCONSV* increases from zero to the calculated value in (9), then remains nearly constant. In contrast, the variation in NSV is temporary during non-islanding events, and *ROCONSV* eventually returns to zero.

During non-islanding events, a rapid NSV change causes a large *ROCONSV* value, which quickly returns to zero. Therefore, a suitable time delay (the “Delay” block in Fig. 2) avoids false detections from rapid NSV variations. Conversely, a slower NSV variation produces a smaller *ROCONSV*, which takes longer to return to zero. Thus, an appropriate *ROCONSV* threshold (the “>Th?” block in Fig. 2) helps prevent false detection. Section III provides a detailed explanation of the process for setting the threshold and time delay.

C. Band Pass Filter (Y_f) Design

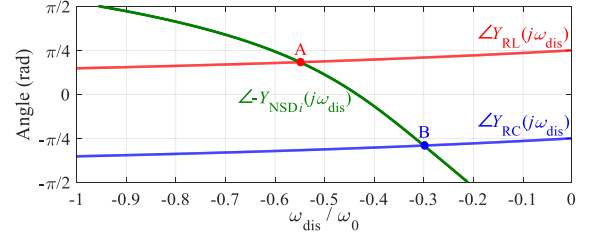
Three key aspects are considered in the design process of the BPF (Y_f): the NSD frequency must lie within the range of $[-\omega_{max}, -\omega_{min}]$, the VSI remains stable in GC, and it becomes unstable after islanding in a multi-inverter system.

1) *Oscillation Frequency Within a Desired Range*: The NSD frequency expression is initially established to ensure that the post-islanding NSD frequency falls within the desired range. The impedance model of Fig. 1 for the multi-PV system in islanding mode is obtained as in Fig. 4 to support this. Since the NSD becomes saturated after island formation, the model uses the saturated currents. In this condition, the NSC flowing into the inductor filter can be obtained by:

$$I_{LDQi}(j\omega_{dis}) = |G_{ci}(j\omega_{dis})| I_{max i}^- \angle [-Y_{NSDi} V_{tDQi}(j\omega_{dis})] \quad (10)$$

The index i indicates the PV number. The sum of injected NSCs flows into the RLC load with admittance of Y_{RLC} :

$$\sum_{i=1}^N \underbrace{|G_{ci}(j\omega_{dis})| I_{max i}^- \angle [-Y_{NSDi} V_{tDQi}(j\omega_{dis})]}_{I_{LDQi}} = Y_{RLC} V_{tDQ}(j\omega_{dis}) \quad (11)$$

Fig. 5. Y_f filter design illustration for ω_{dis} being in $[-\omega_{max}, -\omega_{min}]$ range.

The per-unit impedance of distribution transformers is typically less than 6% [33]. Therefore, the voltage drops across the Z_{Ti} terms are small and can be neglected compared to the voltage across Y_{RLC} (i.e., $V_{tDQi} \approx V_{tDQ}$). If (11) is multiplied by $1 \angle -V_{tDQ}$, we have:

$$\sum_{i=1}^N |G_{ci}(j\omega_{dis})| I_{max i}^- \angle [-Y_{NSDi}(j\omega_{dis})] = Y_{RLC}(j\omega_{dis}) |V_{tDQ}| \quad (12)$$

This complex equation establishes the equilibrium point of the NSV amplitude ($|V_{tDQ}|$) and NSD frequency (ω_{dis}) at steady-state. By setting the phase of both sides of (12) equal, the NSD frequency can be determined as follows:

$$\angle \left[\sum_{i=1}^N |G_{ci}(j\omega_{dis})| I_{max i}^- \angle [-Y_{NSDi}(j\omega_{dis})] \right] = \angle Y_{RLC}(j\omega_{dis}) \quad (13)$$

The ω_{dis} value depends on various parameters including $|G_{ci}|$, the NSD limit, the phase of Y_{NSDi} in different PV systems, and the phase of the RLC load admittance. To simplify the analysis, it is initially assumed that the microgrid incorporates only a single PV unit, such as the i^{th} PV system. Therefore, the NSD frequency expression can be simplified to:

$$\angle -Y_{NSDi}(j\omega_{dis}) = \angle Y_{RLC}(j\omega_{dis}) \quad (14)$$

In this study, the RLC load is considered according to the IEEE Std. 1547.1-2020 test procedure, with a maximum effective quality factor of 1. The upper boundary of $\angle Y_{RLC}$ is observed when $Q_C = 0$ and $Q_L = P_L$ (inductive load), denoted as Y_{RL} and represented by the red line in Fig. 5. Conversely, the lower boundary occurs when $Q_L = 0$ and $Q_C = P_L$ (capacitive load), denoted as Y_{RC} and shown by the blue line.

In Fig. 5, a sample design of $\angle -Y_{NSDi}(j\omega_{dis})$ is also depicted by the green line, intersecting the upper and lower boundaries of $\angle Y_{RLC}(j\omega_{dis})$ at points A and B, respectively. It is evident that any $\angle Y_{RLC}(j\omega_{dis})$ diagram, which always lies between the blue and red boundaries, will intersect $\angle -Y_{NSDi}(j\omega_{dis})$ at a frequency between crossing points of A and B, i.e., (14) is satisfied within the $[\omega_A, \omega_B]$ range and the NSD frequency lies within this range. By setting the frequency of points A and B at $-\omega_{max}$ and $-\omega_{min}$, respectively, the NSD frequency will be confined within the range $[-\omega_{max}, -\omega_{min}]$. This condition is

realized when the following equations are fulfilled:

$$\begin{cases} \angle -Y_{\text{NSD}i}(-j\omega_{\text{max}}) = \angle Y_{\text{RL}}(-j\omega_{\text{max}}) = \theta_{\text{max}}; \text{ point A} \\ \angle -Y_{\text{NSD}i}(-j\omega_{\text{min}}) = \angle Y_{\text{RC}}(-j\omega_{\text{min}}) = \theta_{\text{min}}; \text{ point B} \end{cases} \quad (15)$$

The equation for determining the NSD frequency in a multi-inverter system was given in (13). By satisfying (15) for each PV system, the complex term inside the Σ operator in (13) will represent the same phase at $\omega_{\text{dis}} = -\omega_{\text{max}}$ and $-\omega_{\text{min}}$ for $i = 1$ to N . As a result, their summation will also be in-phase with each individual term, meaning the left-hand side of (13) equals θ_{max} and θ_{min} at $\omega_{\text{dis}} = -\omega_{\text{max}}$ and $-\omega_{\text{min}}$, respectively. This indicates that its diagram intersects upper and lower boundaries at $-\omega_{\text{max}}$ and $-\omega_{\text{min}}$ frequencies. Therefore, similar to the previous analysis, (13) is satisfied for ω_{dis} values within the $[-\omega_{\text{max}}, -\omega_{\text{min}}]$ range for the multi-PV system as well. Also, by this uniform phase design, NSDs in different DERs amplify each other without the need for synchronization devices.

2) *Instability in Islanding Conditions:* The criterion for determining the stability of the multi-inverter system can be obtained through the following analysis. Referring to (A.1) in the Appendix, (4) can be rewritten in the form of (16). The VSI in a single-PV system becomes unstable after islanding occurrence if:

$$\frac{\text{Re}[-Y_{\text{NSD}i}(j\omega_{\text{dis}})]}{\text{Re}[Y_{\text{RLC}}(j\omega_{\text{dis}})]} \Big|_{\angle -Y_{\text{NSD}i}(j\omega_{\text{dis}}) = \angle Y_{\text{RLC}}(j\omega_{\text{dis}})} > 1 \quad (16)$$

As per the earlier design objective, the equation $\angle -Y_{\text{NSD}} = \angle Y_{\text{RLC}}$ holds for $\omega_{\text{dis}} \in [-\omega_{\text{max}}, -\omega_{\text{min}}]$. Therefore, the condition $\angle -Y_{\text{NSD}} = \angle Y_{\text{RLC}}$ in the above equation can be simply replaced by $\omega_{\text{dis}} \in [-\omega_{\text{max}}, -\omega_{\text{min}}]$ and (16) can be rewritten as follows:

$$\text{Re}[-Y_{\text{NSD}i}(j\omega_{\text{dis}})] > \text{Re}[Y_{\text{RLC}}(j\omega_{\text{dis}})] = \frac{1}{R} = \frac{P_L}{V_n^2} \quad (17)$$

$\omega_{\text{dis}} \in [-\omega_{\text{max}}, -\omega_{\text{min}}]$

The above condition is more likely to be violated for greater P_L on the right side of (17), leading to the failure of the proposed IDT. Hence, the reliability of the presented method is ensured when (17) is met for the maximum P_L . According to IEEE Std. 1547.1-2020 test procedure, the maximum P_L is $P_{\text{PV}i}$. By applying the Σ operator to (17) for $i = 1$ to N , and substituting $P_L = P_{\text{PV}i}$, the following inequality is obtained:

$$\text{Re} \left[\sum_{i=1}^N -Y_{\text{NSD}i}(j\omega_{\text{dis}}) \right] > \frac{1}{V_n^2} \sum_{i=1}^N P_{\text{PV}i}; \omega_{\text{dis}} \in [-\omega_{\text{max}}, -\omega_{\text{min}}] \quad (18)$$

Equation (18) serves as the criterion for small-signal instability of the multi-PV system, assuming an active load equal to the sum of the PV nominal powers. If (17) holds for each PV system for $P_L \leq P_{\text{PV}i}$, the multi-PV system will become unstable after islanding when $P_L \leq \sum_{i=1}^N P_{\text{PV}i}$.

3) *Stable Performance in GC Operation:* In GC mode, the admittance seen at the PV terminal is the sum of the RLC load and the utility grid admittance (Y_G). In the worst-case scenario, it is assumed that there is no load. The DER control system is

small-signal stable in GC mode when (19) is satisfied [32]:

$$\left| \frac{Y_{\text{NSD}i}(j\omega_{\text{dis}})}{Y_G(j\omega_{\text{dis}})} \right|_{\angle -Y_{\text{NSD}i}(j\omega_{\text{dis}}) = \angle Y_G(j\omega_{\text{dis}})} < 1 \quad (19)$$

Y_G can be described in terms of the grid short-circuit ratio (SCR) and X/R ratio. In this work, stability in GC is ensured for a weak grid, as discussed in the next subsection.

4) *Proposed Y_{fi} Structure and Parameters:* Multiple solutions for Y_{fi} can simultaneously meet the conditions described in (15), (17), and (19). However, this study proposes a BPF in the form of (20), which includes a washout (first-order high-pass filter) and a low-pass filter (LPF). The cutoff frequency of the washout filter (ω_{wo}) is set to ω_{min} . The LPF must be at least second-order to satisfy the two constraints in (15):

$$\begin{aligned} & \begin{bmatrix} i'_{\text{dis}Di} \\ i'_{\text{dis}Qi} \end{bmatrix} \\ &= \frac{s}{s + \omega_{\text{wo}}} \cdot \frac{\omega_{ni}^2}{s^2 + 2\zeta_i\omega_{ni}s + \omega_{ni}^2} \begin{bmatrix} K_{Di} & -K_{Qi} \\ K_{Qi} & K_{Di} \end{bmatrix} \cdot \begin{bmatrix} v_{tD}^- \\ v_{tQ}^- \end{bmatrix} \end{aligned} \quad (20)$$

The filter has a symmetric 2×2 transfer matrix, which can be described in its complex form as:

$$Y_{fi}(s) = \frac{s}{s + \omega_{\text{wo}}} \cdot \frac{K_{DQi}\omega_{ni}^2}{s^2 + 2\zeta_i\omega_{ni}s + \omega_{ni}^2}; K_{DQi} = K_{Di} + jK_{Qi} \quad (21)$$

where K_{DQi} , ζ_i and ω_{ni} represent the gain at $s = 0$, damping ratio, and natural frequency of LPF.

The LPF parameters are determined through a systematic trial-and-error process. By varying $\angle K_{DQi}$, the two linear expressions in (15) are solved to find ζ_i and ω_{ni} . Among various values of $\angle K_{DQi}$, the one that provides the optimum margins for both (17) and (19) is selected. A larger $|K_{DQi}|$ raises the margin for (17), i.e., reduces the detection time, but decreases the margin for (19), which may lead to system instability for SCR and X/R ratios associated with weak grids. Therefore, $|K_{DQi}|$ is selected to provide at least 25% margin for (17) while ensuring zero NDZ and stable DER operation in GC mode for $\text{SCR} \geq 2.5$ and $X/R \geq 0.1$ as a weak grid scenario.

III. THRESHOLD SETTINGS DETERMINATION

After island formation, the NSD and the $ROCONSV$ increase. The proposed IDT identifies an islanding event when $ROCONSV > Th$ is met for more than a time delay (T_{Delay}). This section focuses on the criteria for selecting these settings.

A. $ROCONSV$ Threshold

The threshold must be smaller than the minimum $ROCONSV$ in all islanding scenarios. According to (9), the $ROCONSV$ depends on NSV amplitude ($|V_{tDQ}|$) and NSD frequency. These two parameters are determined by (12). By equating the real part of both sides of (12) and considering $\text{Re}[Y_{\text{RLC}}] = P_L/V_n^2$, the

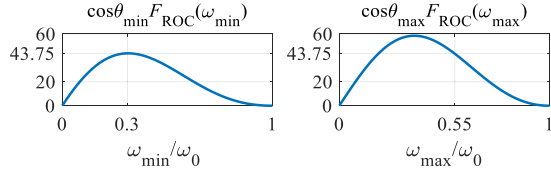


Fig. 6. Plot of the terms within the “min” function in (26).

following equation is derived:

$$\sum_{i=1}^N |G_{ci}(j\omega_{dis})| I_{\max i}^- \cos \angle [-Y_{NSDi}(j\omega_{dis})] = \frac{P_L}{V_n^2} |V_{tDQ}| \quad (22)$$

$ROCONSV$ is equal to $|V_{tDQ}| \times F_{ROC}$ according to (9). By combining (9) and (22), we have:

$$ROCONSV = \frac{V_n^2}{P_L} \sum_{i=1}^N |G_{ci}(j\omega_{dis})| I_{\max i}^- \cos \angle [-Y_{NSDi}(j\omega_{dis})] F_{ROC}(\omega_{dis}) \quad (23)$$

$I_{\max i}^-$ is selected according to the minimum gain of current controller (G_c) within the $[-\omega_{\max}, -\omega_{\min}]$ range such that:

$$|G_c(j\omega_{dis})| I_{\max i}^- \geq K_{NSC} I_{ni} \quad (24)$$

Where I_{ni} is the nominal current of the i^{th} PV system. K_{NSC} is a fixed coefficient among all inverters which determines the minimum per-unit NSC injected into the grid by each inverter after islanding occurrence. Substituting the inequality of (24) in (23) results in:

$$ROCONSV \geq K_{NSD} V_n \frac{1}{P_L} \sum_{i=1}^N P_{PVi} \cos \angle [-Y_{NSDi}(j\omega_{dis})] F_{ROC}(\omega_{dis}) \quad (25)$$

According to the Y_{NSDi} design for all PV systems, the term $\cos \angle -Y_{NSDi}(j\omega_{dis})$ in (25) varies from $\cos \theta_{\max}$ to 1, and then to $\cos \theta_{\min}$ as the ω_{dis} changes from $-\omega_{\max}$ to $-\omega_{\min}$. Hence, the minimum $ROCONSV$ in (25) is obtained at $-\omega_{\max}$ or $-\omega_{\min}$ frequencies. By applying a safety margin, the threshold is set at 80% of the minimum $ROCONSV$ as follows:

$$Th = 0.8 K_{NSD} V_n \frac{1}{P_L} \underbrace{\sum_{i=1}^N P_{PVi} \min \left\{ \cos \theta_{\min} F_{ROC}(\omega_{\min}), \cos \theta_{\max} F_{ROC}(\omega_{\max}) \right\}}_{\gamma^{-1}} \quad (26)$$

where γ is defined as the ratio of the load active power to the sum of PV nominal powers.

As outlined in the following subsection, a higher threshold reduces the likelihood of false trips while allowing for a shorter delay, thereby decreasing the islanding detection time. The threshold in (26) reaches its maximum value when both terms within the “min” function are maximized, which are plotted in Fig. 6. The first term attains its maximum value when $\omega_{\min} = 0.3\omega_0$. By setting $\omega_{\max} \leq 0.55\omega_0$, the second term becomes equal to or greater than the first term, ensuring that the “min” function equals the first term’s maximum value of 43.75. To

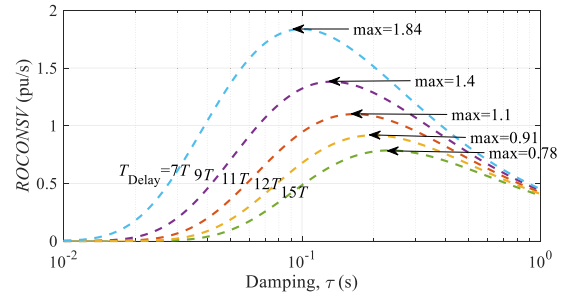


Fig. 7. $ROCONSV$ during LL fault (greatest change in NSV) for different T_{Delay} (dotted lines), and $ROCONSV$ thresholds for different K_{NSD} values (solid lines).

TABLE II
TWO PARAMETER SETS FOR PROPOSED METHOD’S EVALUATION

Parameter	~5% (Fast)	~3% (Conservative)
Gain (K_{NSD})	0.04	0.022
Threshold (Th)	1.4 pu/s	0.78 pu/s
Time delay (T_{Delay})	9T (150 ms)	15T (250 ms)

extend the range as much as possible, $\omega_{\max} = 0.55\omega_0$ is chosen. With this selection, the per-unit threshold in (26) is given as:

$$Th_{pu} = Th/V_n = (0.8 K_{NSD}/\gamma) \times 43.75 = 35 K_{NSD}/\gamma \quad (27)$$

The worst case of P_L for islanding detection, as per IEEE Std. 1547.1 2020, equals the total PV nominal power, i.e., the maximum γ is assumed to be 1 in this study.

B. Time Delay Setting

As discussed earlier, non-islanding events result in a temporary increase in $ROCONSV$. The most severe case occurs during phase-to-phase faults, where the maximum change in NSV reaches 0.5 pu. In addition to the amplitude of change, $ROCONSV$ depends on how the NSV changes over the calculation period. To model its behavior, the change in NSV is expressed by the following first-order approximation:

$$\Delta v_{tDQ}(t) = \Delta v_{tDQss} (1 - e^{-t/\tau}) \quad (28)$$

where Δv_{tDQss} represents the change in NSV amplitude, and τ is its time constant [14]. Based on (8) and (28), $ROCONSV(t)$ is computed for different delay (T_{Delay}) and time constants (τ) under $\Delta v_{tDQss} = 0.5$ pu. The results are depicted in Fig. 7, which also includes the maximum $ROCONSV$. The figure clearly illustrates that, regardless of τ , false detection can be avoided ($ROCONSV < Th$) for any threshold (Th) by selecting an appropriate time delay. Also, a higher Th (i.e., greater K_{NSD}) necessitates a shorter T_{Delay} , leading to a reduced islanding detection time. Therefore, a trade-off exists between lowering K_{NSD} and minimizing islanding detection time. To evaluate this trade-off, two distinct parameter sets are selected as summarized in Table II: a ~5% injection limit prioritizing fast detection, and a stricter ~3% limit for conservative operation.

TABLE III
STUDIED PV SYSTEMS SPECIFICATIONS

	PV ₁	PV ₂	PV ₃
P_{py}	1 MW	1.3 MW	1.6 MW
Interface transformer	0.48/4.16 kV DYn11, 1.2 MVA	0.48/4.16 kV DYn11, 1.6 MVA	0.48/4.16 kV DYn11, 2 MVA
G_{ci} Bandwidth	750 rad/s	650 rad/s	550 rad/s
LC filter	0.15 mH/200 μ F	0.12 mH/200 μ F	0.1 mH/200 μ F
DC link capacitor	20 mF	25 mF	30 mF
I_{maxi}^* (A) for ~5%	82.3 (4.84%)	113.3 (5.12%)	151.4 (5.56%)
I_{maxi}^* (A) for ~3%	46.2 (2.72%)	63.6 (2.87%)	84.9 (3.12%)
K_{DOI} (Ω^{-1})	18.0 $\angle$ -103°	20.0 $\angle$ -120°	24.3 $\angle$ -123°
ζ_i	0.48	0.46	0.45
ω_{ni}	164.3 rad/s	174.4 rad/s	178.1 rad/s

TABLE IV
SINGLE-PV ISLANDING DETECTION CASES BASED ON IEEE STD. 1547.1-2020

Test No.	PV active power and mode	PV reactive power and mode	P_L	Q_C	Q_L	Det. time (ms)		ω_{dis} (rad/s)
						Fast	Cons.	
1B	1.00	VW+	0.00	1.00	1.00	275	360	-0.35 ω_0
2B	0.50	FW	0.00	0.50	0.50	222	315	-0.34 ω_0
3B	0.90	CPF	-0.44	0.90	0.90	267	353	-0.33 ω_0
4B	0.90		0.44	0.90	0.90	252	341	-0.42 ω_0
5B	1.00	VV	0.00	1.00	1.00	273	358	-0.35 ω_0
6B	0.50		0.00	0.50	0.50	222	314	-0.34 ω_0
7B	0.50	WV	0.00	0.50	0.50	221	314	-0.34 ω_0
8B	1.00		0.00	1.00	1.00	267	354	-0.34 ω_0
9B	0.50	CRP	-0.44	0.50	0.50	218	310	-0.32 ω_0
10B	0.50		0.44	0.50	0.50	226	318	-0.50 ω_0

IV. SIMULATION RESULTS AND DISCUSSION

In this section, the performance of the proposed IDT is demonstrated through extensive islanding and non-islanding simulations in PSCAD-EMTDC, followed by an in-depth comparison with recent active IDTs. The method is evaluated using the two parameter sets detailed in Table II. The single-PV tests utilize the system shown in Fig. 1 (configured as PV1 in Table III). For the multi-PV scenarios, the IEEE 13-bus test feeder is simulated with three PV systems connected to different buses, as characterized in Table III.

A. Single-PV Test Based on IEEE Std. 1547.1-2020

IEEE Std. 1547.1-2020 recommends assessing islanding detection performance using a combination of different power levels [3]. The ancillary services of Volt-Watt (VW), frequency-Watt (FW), constant power factor (CPF), Watt-VAr (WV), Volt-VAr (VV), and constant reactive power (CRP) are activated in the islanding test cases, as listed in Table IV [3].

Islanding is simulated by opening the main CB at $t = 0.5$ s. For each row of Table IV, eleven tests are conducted, in which the reactive power mismatch varies with a 1% step from -5% to +5%. The minimum $ROCONSV$ value and the maximum detection time for each row are provided in Table IV for both parameter sets. Also, the dynamic simulation results of two cases are shown in Fig. 8.

The results in Table IV indicate successful islanding detection of the proposed technique in all tests. For the fast setting (using a threshold of 1.4 pu/s), in the worst cases of 1B, 5B, and 8B with a greater active load, islanding is identified within 275 ms. While conservative setting (threshold of 0.78 pu/s) exhibits slightly

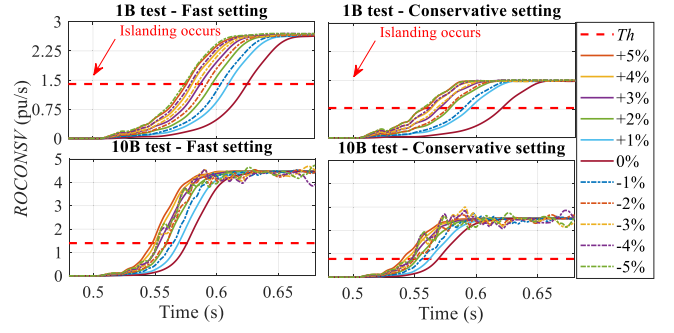


Fig. 8. $ROCONSV$ for 1B and 10B test cases of Table IV.

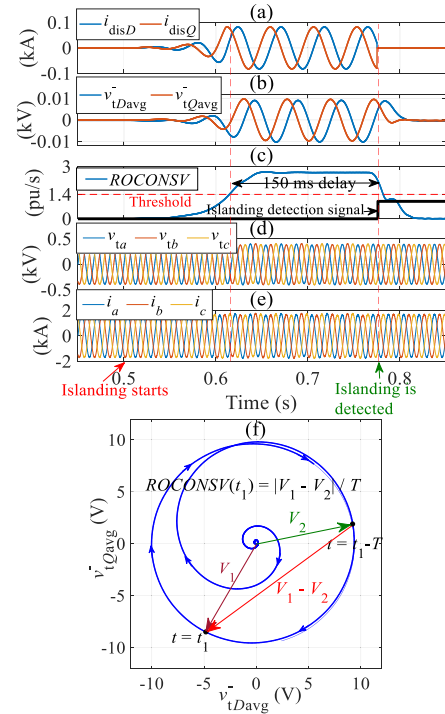


Fig. 9. Simulation results for a well-balanced island (1B case): (a) DQ NSD (i_{disD} and i_{disQ}), (b) DQ NSV (v_{tDavg} and v_{tQavg}), (c) $ROCONSV$, (d) three-phase voltage at the PV terminal (v_{ta} , v_{tb} , and v_{tc}), (e) output current of PV (i_a , i_b , and i_c), and (f) v_{tDavg} in the complex plane.

longer detection times due to the reduced injection gain, it consistently meets the standard requirements (2 s limit).

Fig. 9 illustrates the proposed IDT's detection process for the 1B balanced case under the fast parameter set. Before islanding formation, the NSD is almost zero, underlining the negligible negative impact on PQ during GC operation. When islanding occurs, the VSI becomes unstable, and the NSD increases, reaching its amplitude limit of 82.3 A (4.84%) within ~110 ms (Fig. 9(a)). Thus, the NSV (Fig. 9(b)) and $ROCONSV$ (Fig. 9(c)) increase due to the rise in the injected disturbance. The $ROCONSV$ exceeds the preset threshold (1.4 pu/s) after 125 ms. Considering the corresponding 150 ms delay, islanding is identified after 275 ms. Once islanding is detected, the NSD is set to zero, and the NSV decays to zero shortly (Fig. 9(b)). The PV system

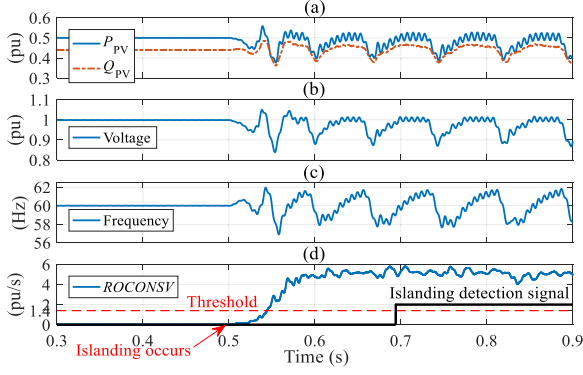


Fig. 10. Results for 10B test case: (a) PV active/reactive output power, (b) positive sequence voltage at the PV terminal, (c) frequency, and (d) $ROCONSV$.

experiences no significant distortions in voltage or current at its terminal during the clearance time (Fig. 9(d) and (e)). This implies that the proposed IDT facilitates a seamless transition from GC to standalone operation.

The $ROCONSV$ calculation in (8) is illustrated in Fig. 9(f) by plotting the v_{tDQavg}^- diagram for $t \in [0.45 \text{ s}, 0.7 \text{ s}]$ in the complex plane. When islanding starts, v_{tDQavg}^- begins from the origin and rotates clockwise, indicating a negative angular frequency. After a short duration, v_{tDQavg}^- follows a circular path centered at the origin. The $ROCONSV$ calculation is shown for a chosen time t_1 . This figure reveals how the $ROCONSV$ value grows and remains almost constant just after an islanding event. This performance demonstrates that $ROCONSV$ is an effective criterion for islanding detection.

Fig. 10 shows simultaneous realization of the proposed IDT and ancillary services for the 10B test case with a reactive power mismatch of +5%, simulated using the fast setting. The reactive power mismatch is expected to shift the frequency to 61.5 Hz. However, voltage and frequency undergo sustained oscillations due to active/reactive power regulations (Fig. 10(b) and (c)). In this condition, voltage- and frequency-based IDTs repeatedly pick up and drop out before completing their operation time, resulting in failed islanding detection. Nevertheless, the proposed IDT successfully detects islanding after about 200 ms, (Fig. 10(d)). This successful performance is achieved since the proposed IDT is not affected by positive sequence components.

The ω_{dis} values obtained in simulations are also given in Table IV. A more inductive load and smaller compensation brings $\angle Y_{RLC}$ closer to the red line in Fig. 5 ($\angle Y_{RL}$). Hence, $\angle Y_{RLC}$ crosses $\angle Y_{NSD}$ at a more negative ω_{dis} . The ω_{dis} values in Table IV align with this analysis, confirming the validity of the presented Y_{fi} filter design.

B. Multi-PV Microgrid Tests

The performance of the proposed IDT is evaluated in a larger-scale multi-PV network. To this end, the modified IEEE 13-bus standard distribution feeder in Fig. 11 is simulated. The network consists of single- and three-phase loads, including a mix of constant impedance (Z), constant current (I), and constant power (P) types [34].

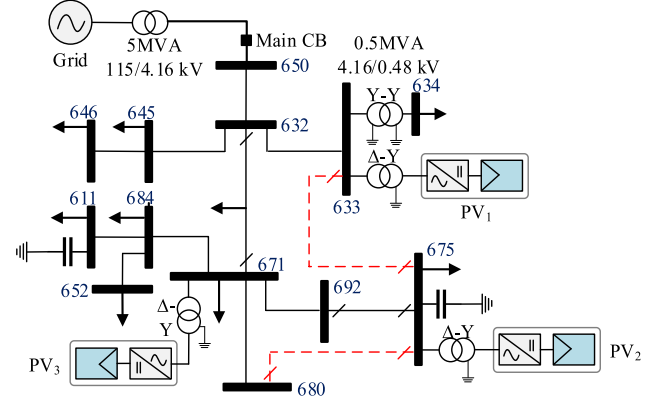


Fig. 11. IEEE 13-bus standard test grid with three connected PV systems.

TABLE V
MULTI-PV ISLANDING CASES AND RESULTS

Grid	Case No.	PV power P+jQ (MVA)	Load power P+jQ (MVA)	Comp. MVar	Z/I/P (%)	3 ϕ B/U	Detection time(ms)		
							Fast	Cons.	
13-bus	1, 9	3.59+j1.52	3.47+j2.10	0.70	10/10/80	U	352, 363	419, 434	
	2, 10	3.59+j1.52	3.47+j2.10	0.70	10/10/80	B	262, 274	348, 362	
	3, 11	3.59+j0.00	3.47+j2.10	2.22	10/10/80	B	257, 295	342, 382	
	4, 12	3.59-j1.52	3.47+j2.10	3.76	10/10/80	B	263, 302	343, 382	
	5	3.54+j1.52	3.47+j2.10	0.70	80/10/10	U	212	265	
	6	3.54+j1.52	3.47+j2.10	0.70	80/10/10	B	232	321	
	7	3.54+j0.00	3.47+j2.10	2.20	80/10/10	B	231	319	
	8	3.54-j1.51	3.47+j2.10	3.73	80/10/10	B	250	336	
34-bus	13	1.72+j0.24	1.77+j1.05	0.75	38/32/30	U	271	344	
	14	1.72+j0.61	1.77+j1.05	0.35	38/32/30	B	227	314	
	15	1.72+j0.00	1.77+j1.05	1.04	38/32/30	B	229	316	
	16	1.72-j0.66	1.77+j1.05	1.74	38/32/30	B	253	329	

Table V details the multi-DER islanding test cases and summarizes the detection performance for both parameter sets. The initial case represents the original state of the IEEE 13-bus network, characterized by significant load unbalance (U). To investigate three-phase balanced loading cases, the load on bus 675 is modified, as indicated by “B” in the 3 ϕ B/U column. Additional capacitive compensation is applied at buses 671, 675, and 632 to achieve unity and leading power factors (PFs). The loads are dominantly constant power in Cases 1–4 and constant impedance in Cases 5–8. In all cases, the output power of the PV systems is adjusted to achieve a near-zero mismatch of 0.0256% (1+j1 kVA). At $t = 0.5 \text{ s}$, the system is islanded by opening the main CB. The $ROCONSV$ for the fast setting for all PV units are depicted in Fig. 12.

The islanding events in Table V are successfully detected by all PV systems under both settings. For the fast case shown in Fig. 12, the detection time is less than 263 ms, except for Case 1. The extended detection time in Case 1 is attributed to overvoltage in two phases (1.3 pu) at the PV₃ terminal due to severe three-phase unbalanced loads. This condition leads to over-modulation of the VSI. Therefore, the VSI fails to track its reference, resulting in incomplete injection of the disturbance current. Despite this, islanding is finally identified after 352 ms. The simulation results reveal accurate and timely detection of all islanding cases under different active powers of the PV systems using the predefined thresholds (1.4 pu/s for the fast and 0.78 pu/s

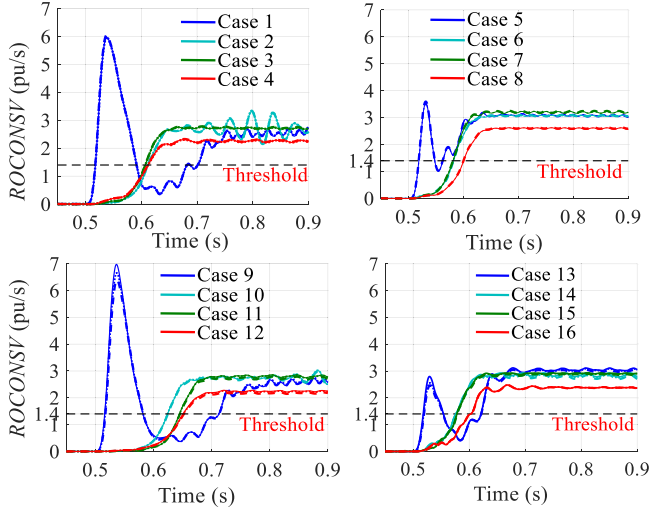


Fig. 12. $ROCONSV$ for multi-PV islanding cases utilizing the fast setting (solid lines: PV_1 , dotted lines: PV_2 , and dashed lines: PV_3).

for the conservative setting). This performance corroborates the analytical threshold expression in Section III.

C. Evaluation Under Topology Reconfiguration and Different Systems

To evaluate the robustness of the proposed IDT to both network topology changes and different microgrid configurations, the following simulations are conducted:

1) *Topology Reconfiguration of the 13-Bus System:* The standard test feeder is modified by altering its line connections.

Specifically, lines 632–671 and 692–675 are taken out of service, and two new branches, lines 633–675 and 675–680, are introduced. This modification changes the electrical distances between DER units, without significantly affecting the overall load or generation levels. The new lines are assigned lengths of 2 km and 1 km, respectively, and are modeled with a different X/R ratio of 5. Test Cases 1–4 are repeated under this reconfigured topology, and the corresponding results (Cases 9–12) are provided in Fig. 12 and Table V. For the fast setting shown in Fig. 12, the $ROCONSV$ waveform confirms reliable islanding detection under this topology change within a maximum of 363 ms.

2) *Validation on IEEE 34-Bus System:* This system is characterized by a nominal voltage of 24.9 kV, long and lightly loaded feeders, multiple in-line regulators, and a different mix of constant impedance/current/power loads compared to the IEEE 13-bus test system. [34]. Three DERs are connected at buses 808, 854, and 860 with ratings of 0.5, 0.65, and 0.8 MW, respectively. Four operating conditions are studied: the base case with unbalanced three-phase loading, and balanced loading with PF values of 0.93 lag, unity, and 0.93 lead. The results, shown in Fig. 12 (Cases 13–16), demonstrate that the $ROCONSV$ indicator consistently crosses the predefined threshold (1.4 pu/s for the fast setting), confirming effective islanding detection across all scenarios in less than 271 ms. These results demonstrate that the proposed IDT is robust to both topology reconfigurations

TABLE VI
RESULTS OF SIMULATED NON-ISLANDING EVENTS

Case No.	Event type	Description	Peak (pu)	$ROCONSV$		Disturbance Peak (%)
				Fast	Cons.	
1	LLLG fault	0.01 Ω	7.3	42	51	3.2 / 5.6*
2	LLG fault	0.01 Ω	21.5	44	60	3.2 / 5.6*
3	LL fault	0.01 Ω	25.8	53	62	3.2 / 5.6*
4	SLG fault	0.01 Ω	12.3	42	54	3.2 / 5.6*
5	SLG fault	1 Ω	6.9	44	56	3.2 / 5.6*
6	Cap switch.	2 MVar	1.8	2	6	3.2 / 5.6*
7	Load switch.	1.33 MVA	0.8	0	4	3.2 / 5.6*
8	IM switch.	2 MW	2.0	11	16	3.2 / 5.6*
9	Trans. Energ.	2 MVA	1.1	0	11	3.2 / 5.6*
10	Cap. switch.	0.6 MVar	0.24	0	0	1.5
11	1 ϕ cap. switch.	0.2 MVar	0.29	0	0	2.0
12	Load switch.	0.6 MVA	0.29	0	0	2.7
13	1 ϕ load switch.	0.2 MVA	0.41	0	0	3.0
14	Cap switch.	0.3 MVar	0.14	0	0	0.9
15	1 ϕ cap. switch.	0.1 MVar	0.15	0	0	1.0
16	Load switch.	0.3 MVA	0.15	0	0	1.4
17	1 ϕ load switch.	0.1 MVA	0.21	0	0	1.5

* Depends on the parameter setting

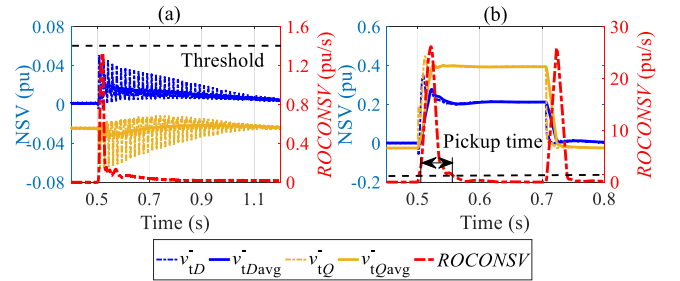


Fig. 13. Results in non-islanding scenarios: (a) A transformer energization (Case 9), and (b) Fault occurs at $t = 0.5$ s and is cleared at $t = 0.7$ s (Case 3).

and different microgrid systems, maintaining high detection reliability regardless of the selected setting.

D. Non-islanding Events

In addition to accurate islanding detection, an IDT should avoid false tripping during non-islanding events. Table VI lists the non-islanding disturbances, simulated at the PV_3 terminal, ranging from severe faults (Cases 1–5) to switching operations and light transients (Cases 6–17). The faults initiate at $t = 0.5$ s and are cleared at $t = 0.7$ s. During switching events, the equipment's breaker closes and opens at $t = 0.5$ s and 0.7 s, respectively. In Case 9, a transformer is connected to the bus at $t = 0.5$ s.

Table VI provides the maximum $ROCONSV$ and the pickup time (duration where $ROCONSV > Th$) for both the fast and conservative parameter sets. As shown, severe faults cause the $ROCONSV$ to momentarily exceed the threshold due to sharp NSV variations. However, the maximum recorded pickup time is 62 ms (observed in Case 3 with the conservative setting). This is significantly shorter than the respective time delays of 150 ms and 250 ms. Hence, neither setting triggers a false trip, confirming the method's security against nuisance tripping.

For brevity, Fig. 13 presents detailed results for only two cases: transformer energization and LL fault obtained using the

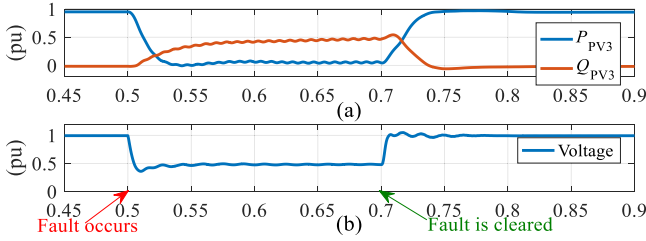


Fig. 14. The details of the LL fault of Fig. 13(b) (a) P_{PV3} output active/reactive power, (b) positive sequence voltage.

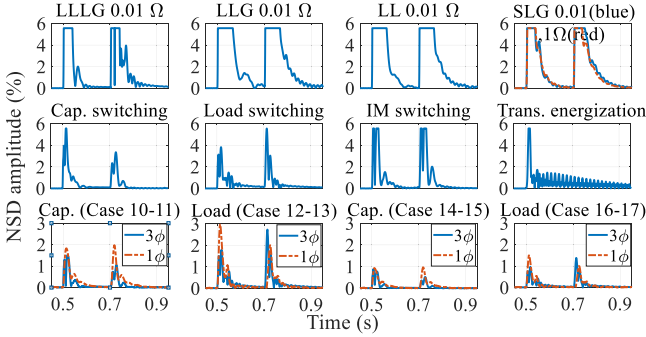


Fig. 15. PV_3 NSD amplitude during events of Table VI for the fast setting.

fast setting. The behavior of v_{tDQ}^- and $v_{tDQ_{avg}}^-$ (on the left axis) along with $ROCONSV$ (on the right axis) are illustrated in this figure. Among all events, the transformer energization (Case 9) shows the longest NSV damping time constant. The NSV initially increases to 4% and then decays gradually. As seen in Fig. 13(a), $ROCONSV$ temporarily spikes but quickly diminishes, resulting in a pickup time of 0–11 ms (depending on the setting), which is well within the safety margin.

The variation of NSV during the LL fault is also depicted in Fig. 13(b). Initially, NSV jumps to 45% at the fault's inception and then remains nearly constant. Since $ROCONSV$ responds to the rate of change, it only rises during the fault's initiation and clearance phases. As shown in Table VI, this results in a pickup time of 53 ms for the fast setting. While the conservative setting records a slightly longer pickup of 62 ms due to the lower threshold (0.78 pu/s), the extended delay of 250 ms (required by the lower threshold) ensures ample security margin. Furthermore, Figs. 13(b) and 14 demonstrate that the IDT complies with LVRT requirements; the DER remains connected and provides reactive power support (Fig. 14(a)) without falsely detecting an island.

The proposed method benefits from an adaptive disturbance injection, which minimizes the impact on PQ. Fig. 15 displays the NSD amplitude during these events. The injection is naturally proportional to the severity of the grid disturbance, capped by the user-defined ceiling.

Table VI highlights two key strengths regarding PQ:

- For frequent but minor events such as small load steps or capacitor switching (Cases 10–17), the method automatically scales down the injection. As shown in Table VI, the peak disturbance for these cases remains between 0.9% and

3.0%, ensuring that routine grid operations do not trigger maximum disturbance injection.

- During severe faults and major switching (Cases 1–9), the injection is strictly limited to the predefined maximum. While the fast setting allows a peak of 5.6%, employing the conservative setting clamps this peak to 3.12%. This capability ensures that the IDT operates unobtrusively, preventing the injection of excessive currents even under the most severe grid conditions.

In conclusion, the simulation results confirm that the proposed method is secure against false tripping. Furthermore, the conservative setting offers a superior balance, maintaining reliable detection while limiting the peak disturbance injection to less than 3.12%, thereby adhering to strict PQ constraints.

E. Comparison With Several Active IDTs

The proposed method is compared with some existing IDTs, summarized in Table VII. These methods are designed for inverter-based DERs and are generally compatible with grid ancillary services and LVRT requirements. The methods are compared in terms of procedure (i.e., disturbance characteristics and detection mechanism), comprehensiveness (i.e., NDZ size, multi-inverter support, and robustness under grid events), and complexity.

- The IDTs in [17], [18], [21], [23], [24], [35], and [36] inject disturbances with a fixed amplitude or periodic pattern, which persistently degrade the THD of the output current.
- Some active IDTs employ decaying disturbance amplitudes to mitigate PQ issues [20], [19], [22]. However, the transient injection in these methods can still be excessive. For instance, the method in [22] triggers a fixed disturbance pattern that reaches $\sim 10\%$ for unbalanced faults and up to $\sim 15\%$ for three-phase faults. In contrast, the proposed IDT utilizes an adaptive injection logic that scales with event severity. This ensures superior PQ by limiting the peak disturbance to a user-defined ceiling, $< 5.6\%$ for the fast setting and $< 3.12\%$ for the conservative setting, while restoring it to zero within < 200 ms.
- In [19], which employs a decaying injection IDT, disturbances may be present even under steady-state conditions due to background voltage unbalance in the utility grid. In the proposed IDT, however, disturbances are triggered only by grid events such as switching and faults, and they diminish to zero under steady-state conditions.
- In methods injecting NSC at zero frequency [19], [23], [24], [35], the coordination across inverters can be achieved using the positive sequence voltage angle from phase-locked loop. However, the injected NSC may reduce the NSV at PCC by compensating the imbalance in the local load. In this condition the IDT fails to detect islanding occurrence. In contrast, the proposed method uses low-frequency injection into DQ axes providing effective detection in asymmetrical load conditions. The synchronization of disturbances is handled locally via closed-loop feedback and input admittance design.

TABLE VII
COMPARISON OF THE PROPOSED IDT WITH SOME EXISTING IDTs COMPLYING WITH ANCILLARY SERVICES/LVRT

Ref	Disturbance characteristics				Detection mechanism	NDZ	Multi-Inverter support	Accuracy in grid events	Complexity
	Mode	Freq.	In axes	Amp. (%)					
[35] [24]	Fixed	0	D/Q	$\frac{5}{2}$	Voltage unbalance	Moderate	Good	Poor	Low
[36]	Periodic pulse pattern	8.3	D/Q	5	Change of voltage unbalance	Small	GPS-dependent	Good	Low
[18]	Fixed	20	d	1	Rate of change of d -axis voltage	Small	GPS-dependent	Good	Low
[23]	Fixed	0	D/Q	1	Inverter NSV $\times$ PCC NSV	Moderate	Good	Poor	Low
[21]	Fixed triggered by frequency deviation	30	d	3	Impedance and its rate of change	Small	GPS-dependent	Good	High
[20]	Periodic Gaussian pattern	60	dq	10	Impedance	Small	GPS-dependent	Good	Low
[17]	Fixed by virtual impedance	240	$\alpha\beta$	1.33	Impedance	Small	Good	Good	High
[19]	Decaying feedback-based	0	D	10	NSV	Moderate	Good	Poor	Low
[22]	Decaying triggered by ROCOSA	30	d	3-15	Superimposed mean variation in voltage and current	Small	Moderate	Good	High
Prop.	Decaying by input admittance shaping	18-33	DQ	Adaptive (<3.2/<5.6)	$ROCONSV$	Small	Good	Good	Moderate

- The techniques in [19], [24], [35] use voltage unbalance or NSV magnitude. These parameters also increase during unsymmetrical non-islanding events which may result in false detection. The proposed method instead monitors the rate of change of NSV which provides better classification.
- Finally, unlike methods which require GPS signals [18], [20], [21], and [36] or zero crossing [22], [25] for synchronization, the proposed method can be implemented with a simple firmware update and does not require additional hardware. While BPF is designed once during manufacturing, the detection threshold and time delay are set by simple relationships during commissioning. These remain valid over a wide range of system conditions, making the method suitable for deployment in microgrid applications.

V. CONCLUSION

The proposed IDT shapes a negative-sequence input admittance at DER terminal by injecting NSD into the DER's current references. Through this, NSDs appear in a multi-inverter system without requiring synchronization or knowledge of transformer vector groups. This disturbance, characterized by its small size and short duration, has negligible impact on PQ during GC operation. In addition, the proposed IDT offers a seamless transition capability to standalone operation and ensures compliance with grid codes and LVRT requirements.

The designed parameters in this study can be readily applied to any inverter-based DER, irrespective of its type, size, and nominal voltage. The Y_f filter parameters and $I_{\max}^-$ can be determined for any DER system according to its G_c transfer function and nominal power. The calculated parameters are independent of the number of DER units within a microgrid. These overall advancements position the proposed IDT as an effective solution for multi-inverter microgrids.

APPENDIX

The following equality can be derived for two complex numbers C_1 and C_2 with identical phases:

$$\left| \frac{C_1}{C_2} \right| = \frac{\text{Re}[C_1]/\cos \angle C_1}{\text{Re}[C_2]/\cos \angle C_2} = \frac{\text{Re}[C_1]}{\text{Re}[C_2]} \quad (\text{A.1})$$

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