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Impact of RES in Contingency Analysis of an Island Power System †

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Abstract

Autonomous island power systems face inherent vulnerability to severe contingency events, yet current N-1 frameworks and thermal-only criteria systematically underestimate operational risk in grids with high renewable penetration. This paper presents an integrated 24 h N-2 contingency assessment explicitly combining transmission line outages with generator failures in a 6-bus island system, using PowerWorld Simulator (GOS Education 21) to evaluate 24,192 contingency cases across four load–RES operating scenarios. Results reveal a critical dual-channel risk structure. Thermal violations and network islanding represent mechanistically distinct failure modes that do not co-occur predictably. Critically, relying solely on thermal criteria misses adequacy impacts equivalent to 638 MWh/day in worst-case conditions. The time-dependent nature of vulnerability underscores the inadequacy of static snapshot analyses. These findings establish that N-2 contingency frameworks for autonomous grids must treat thermal security and islanding outcomes as co-equal metrics, fundamentally challenging conventional deterministic planning approaches.

Keywords: N-2 contingency analysis; network partitioning; autonomous island systems; renewable energy integration; time-dependent security assessment

1. Introduction

Island and non-interconnected power systems are undergoing rapid transformation as renewable energy sources (RES) increasingly displace conventional generation. Unlike large interconnected grids that can share reserves across borders, isolated systems must maintain supply security entirely through local resources. This structural constraint makes them highly vulnerable to severe contingency events, where the simultaneous loss of multiple components can trigger overloads, voltage collapse, or network separation with no external support available [1].

Contingency analysis is a cornerstone of power system security assessment. The N-1 criterion—evaluating system performance after the loss of any single component—has long been the industry standard. However, as renewable penetration grows and operational margins tighten, stricter N-2 criteria are increasingly necessary, particularly in systems with high load-to-capacity ratios. An N-2 contingency is defined here as the simultaneous outage of any two elements from the combined set of transmission branches and generating units. Despite this, studies that explicitly combine transmission line outages with simultaneous generator failures remain scarce. Conventional security analyses typically treat these failure modes separately, failing to capture their compound effects [2].

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Several critical gaps persist in the literature. First, the majority of contingency studies target large interconnected systems, while non-interconnected grids face fundamentally different operational constraints [1], and systematic N-2 methodologies adapted to their specific vulnerabilities remain underdeveloped. Second, most contingency screening tools discard islanding cases outright rather than treating network separation as a critical outcome requiring specific mitigation, an important oversight for systems already operating in isolation. Third, while cascading outage studies have examined RES compounding effects, comprehensive open-access case studies combining N-2 analysis, islanding detection, and moderate RES penetration in a single simulation framework remain absent. Finally, reliability assessment for small autonomous systems with intermittent generation requires probabilistic frameworks that go beyond simple deterministic criteria [3], yet this insight has rarely been extended to N-2 contingency evaluation.

This paper addresses these gaps by presenting a simulation-based N-2 contingency assessment of a reduced 6-bus equivalent of a 150 kV island transmission network, incorporating conventional generation alongside wind and PV. Using PowerWorld Simulator, a 24 h time-step framework is applied across four load–RES operating scenarios, quantifying both thermal violations and islanding-related adequacy proxies. The specific contributions are (i) a combined transmission–generation N-2 contingency framework capturing compound failure effects, (ii) explicit treatment of islanding as a primary outcome metric rather than a discarded case, (iii) quantification of how RES level interacts with N-2 severity in an autonomous grid context, and (iv) identification of two distinct risk channels: (a) thermal security and (b) adequacy under network separation, which do not co-occur across all operating conditions.

The remainder of this paper is organized as follows. Section 2 reviews relevant literature on contingency analysis, non-interconnected systems, RES integration, and islanding. Section 3 describes the methodology, system model, and simulation procedure. Section 4 presents hourly N-2 results across the four scenarios. Section 5 discusses operational implications, and Section 6 concludes with key findings and future research directions.

2. Literature Review

2.1. Contingency Analysis Methodologies and Standards

Contingency analysis is a fundamental pillar of power system security assessment, enabling operators and planners to evaluate system response to component failures before they occur. The N-1 criterion—ensuring acceptable voltage and thermal performance following the loss of any single major component—has served as the industry standard for decades. The evolution to N-k criteria reflects growing system complexity: N-2 and N-3 contingencies are typically applied to critical areas with high load-to-capacity ratios, planning for the simultaneous loss of two or three major units [4]. Evaluating all possible N-2 combinations presents a substantial computational burden, necessitating screening algorithms based on line outage distribution factors (LODFs) to identify critical double outages without exhaustive AC power flow evaluations. For a system with L transmission elements and G generators, exhaustive N-2 analysis considering all combinations requires evaluation of (L + G choose 2) scenarios, leading to practical approaches based on Impact Tracking Structure (ITS) and Overload Tracking Structure (OTS) methods that analyze only a small fraction of the total contingency space.

While the N-1 contingency analysis dominates the literature, comprehensive studies of N-2 scenarios remain comparatively limited, particularly those that examine the simultaneous loss of transmission capacity and generation. Standard practice involves screening thousands of N-1 contingencies with N-2 analysis applied only to selected critical areas. Recent high-performance computing advances have addressed this by implementing

parallel processing techniques to evaluate N-2 contingencies on large test systems with high renewable penetration, incorporating islanding detection as an explicit N-2 outcome rather than a simulation failure [5]. Critically, traditional contingency analysis examines transmission and generation failure modes separately. Transmission N-k contingencies evaluate line and transformer outages assuming all generation remains available, while generation adequacy studies assume intact transmission topology. Research on risk-based expansion planning has begun to model both simultaneously [6], yet systematic analysis of combined generator-plus-line N-2 scenarios as a distinct contingency category remains limited—this separation fails to capture compound vulnerabilities that arise when both infrastructure types fail concurrently.

2.2. Non-Interconnected Systems and RES Integration

Autonomous and non-interconnected power systems face fundamentally different operational constraints compared to interconnected counterparts. The absence of external grid support eliminates the possibility of emergency power imports. A comprehensive review of energy storage systems in non-interconnected European islands emphasized that isolated systems confront unique challenges [7], including vulnerability to voltage instability, frequency deviations, and potential system collapse under contingency conditions [1]. These systems must maintain adequate spinning reserve and inertia entirely from local resources, constraining operational flexibility and increasing vulnerability to simultaneous component failures. A systematic literature review examining pathways to 100% renewable energy in island systems further highlighted that isolated grids require tailored strategies for achieving grid stability, which differ substantially from interconnected network approaches, with contingency planning methodologies specifically adapted to non-interconnected constraints remaining underdeveloped. Early reliability studies demonstrated that simple deterministic criteria—such as fixed capacity reserve margins or loss of the largest unit—are insufficient for systems with high renewable variability, necessitating probabilistic reliability frameworks that account for the intermittent nature of generation resources [3].

The integration of RES introduces additional complexity through the inherent variability and uncertainty of wind and solar generation. Unlike conventional synchronous generators, which provide inherent inertia and fault current contribution, inverter-based renewable sources exhibit fundamentally different dynamic characteristics that can exacerbate post-contingency system response [8]. Studies examining cascading power outages during climate extremes demonstrated the compounding effects of renewable integration, with validation against the Hurricane Fiona blackout in Puerto Rico showing that high renewable penetration can both mitigate and exacerbate cascading failures depending on system configuration [9]. While the Western Wind and Solar Integration Study Phase 3 found that large interconnected systems can maintain adequate frequency response and transient stability with high renewable shares [10], these results do not transfer directly to small autonomous systems with limited reserve margins. Recent work has demonstrated that strategic battery energy storage system (BESS) placement can mitigate more than 90% of contingency-related voltage violations under high-RES uncertainty [11], reinforcing the need for tailored approaches in isolated grid contexts.

2.3. Islanding in Contingency Analysis

Islanding—the partitioning of a power network into electrically isolated subsystems following transmission outages—represents one of the most severe consequences of contingency events, yet most frameworks treat it as an undesirable simulation screening output to be discarded rather than a phenomenon requiring explicit analysis. Graph Neural Network-

based contingency analysis tools explicitly state that contingencies resulting in islanding are discarded during screening, ignoring the reality that transmission outages can partition networks into subsystems that must then operate autonomously—a scenario of immediate relevance for systems already operating in isolated conditions [12].

Topology-based islanding detection methods have emerged as promising approaches for identifying network partitioning in real time. Research has introduced islanding severity indices for ranking cases based on structural separation and operational impact, emphasizing that islanding contingencies represent severe wide-area system failures requiring early detection and coordinated response. Advances in graph theory and centrality measures have been applied to identify critical components whose failure could trigger islanding, using current-flow intermediation centrality to distinguish localized impacts from network-wide cascading effects. Development of controlled islanding strategies—intentional network partitioning as a last line of defense against cascading blackouts—represents an active research area, with IoT-based approaches proposing real-time coherency assessment using PMU data [13]. The present work adopts this perspective, treating islanding explicitly as a primary outcome metric alongside thermal violations rather than discarding it.

2.4. Simulation Tools and Research Gaps

PowerWorld Simulator is one of the industry-leading platforms for comprehensive contingency analysis, supporting both single-element and multiple-element contingency modeling with full Newton–Raphson and DC load flow approaches [7].

Its time-step simulation capability allows examination of system evolution over defined temporal windows following disturbances, which is essential for evaluating transient responses after severe N-2 events in systems where inverter-based resource response differs fundamentally from synchronous generation. Powerworld's island-based automatic generation control (AGC) modeling specifically addresses autonomous system operation, allowing specification of how individual generators within each island respond to contingency-induced power imbalances [14]. Published PowerWorld-based studies have demonstrated applications with FACTS devices on IEEE 6-bus and 14-bus test systems [15], but most focus on larger interconnected systems, leaving a gap in demonstrated applications to autonomous systems in the 6-bus to 30-bus range with moderate renewable penetration.

The review of existing literature reveals five critical gaps that motivate the present study. First, studies explicitly modeling the simultaneous loss of transmission lines and generators as combined N-2 scenarios remain scarce [3]. Second, the vast majority of contingency research targets large interconnected systems. Small autonomous grids face fundamentally different constraints that existing methodologies do not adequately address [1]. Third, islanding is routinely discarded rather than analyzed as a critical operational outcome. Fourth, the intermediate renewable penetration range of 20–30%—a realistic transition state for many autonomous systems—receives less systematic attention than either very high or very low penetration levels. Fifth, comprehensive 24 h time-step N-2 simulations in autonomous systems combining islanding detection with generation outages are absent from open-access literature [14]. The present study addresses these gaps through a 6-bus island case study using PowerWorld Simulator, combining N-2 transmission-generation contingencies, explicit islanding analysis, and moderate RES penetration within a single 24 h simulation framework.

The gaps identified above collectively define the scope of the present study. No existing work combines N-2 transmission-generation contingencies, explicit islanding analysis, and moderate renewable penetration within a single 24 h simulation framework applied to a small autonomous system [14]. The following section describes the methodology

developed to address these gaps, detailing the system model, contingency set definition, and simulation procedure implemented in PowerWorld Simulator.

3. Materials and Methods

This section describes the workflow used in PowerWorld Simulator to evaluate security and islanding behavior of an autonomous transmission network under contingency conditions such as Rhodes in Figure 1.

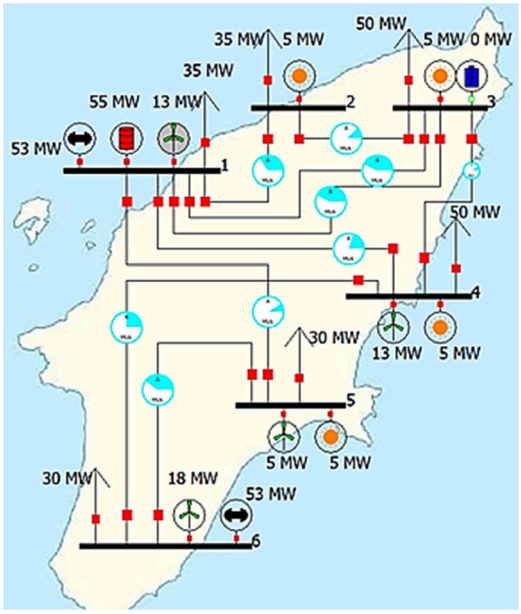


Figure 1. Six-bus equivalent island transmission system, implemented in PowerWorld Simulator (150 kV). The displayed values correspond to a representative operating snapshot and may differ from the aggregate capacities and peak load values discussed in the text.

The network comprises six buses interconnected through seven 150 kV transmission lines. Total conventional generation capacity is approximately 240 MW distributed across four thermal units, while renewable generation includes wind farms totaling 58 MW and photovoltaic installations totaling 36 MW. The slack bus (Bus 1) hosts two conventional units and the primary wind farm, ensuring a consistent reference across all operating hours. Load centers are distributed across all buses, with peak system demand reaching 228 MW under the high-load scenario. The study is carried out as a 24 h simulation with hourly time steps, and the same contingency set and solution settings are applied across all operating scenarios to keep the comparison consistent.

The investigated system is a compact 6-bus representation of an island transmission grid, modeled at the 150 kV level. Branch thermal capability is defined directly in the line data through MVA ratings, and these ratings are used later to determine overload-type violations during contingency analysis. The generation mix includes conventional units and renewable sources (wind/PV) connected at specific buses, consistent with the one-line representation used in the model. A single slack/reference is used at Bus 1, where the two conventional units and the wind unit are located, so that the AC solution has a clear balancing point and a consistent reference across all operating hours and scenarios.

3.1. Operating Scenarios and Simulation Procedure

Four operating scenarios were simulated to capture the combined effect of demand level and renewable production level: Low Load–Low RES, Low Load–High RES, High Load–Low RES, and High Load–High RES. Each scenario is simulated over a complete

day with 24 hourly operating points. The "high-load" operating day corresponds to a representative July day with a maximum system load of approximately 228 MW, while the "low-load" operating day corresponds to a representative November day with a minimum system load of approximately 60 MW. In terms of renewable generation, the same July day reaches approximately 40 MW RES at its maximum, while the November day reaches approximately 16 MW RES at its minimum. In all scenarios, the analysis is conducted over the full 24 h profile so that the results capture intra-day variations and not only a single snapshot. The studied network is a reduced 6-bus representation of an autonomous island transmission system at the 150 kV level. A single slack/reference is used at Bus 1 (hosting two conventional units and the wind unit in the model) to provide a consistent balancing point across all hours and scenarios.

The simulations follow a fixed hourly procedure. First, the system is advanced through the day using Time Step Simulation (TSS) with a step of $\Delta t = 1$ h. For each hour t, the model is set to the corresponding operating point (loads and generation for that hour), and an AC power flow is solved to obtain the pre-contingency state. After the base solution is obtained, Contingency Analysis (CA) is executed for the same hour. This process is repeated for all 24 h, producing hour-by-hour contingency outputs for each scenario.

All contingency calculations are performed using AC Newton–Raphson. The contingency set is identical in all scenarios and includes 252 contingencies per hour, focusing on two-element outage combinations, where generator outages are included among the candidate elements so that the set contains combinations involving transmission elements and generators (as implemented in the PowerWorld CA definition). In order to assess the inherent robustness of the system without additional corrective strategies, remedial actions are disabled. Violations are assessed based on branch thermal limits, i.e., an overload violation is recorded whenever a post-contingency branch flow exceeds its corresponding MVA rating. The violation count reported in this work refers to the number of overloaded branch records identified by the contingency analysis at each operating hour. With 24 h and 252 contingencies per hour, each scenario involves $24 \times 252 = 6048$ contingency evaluations, and the full four-scenario study comprises 24,192 evaluations. In this work, an N-2 contingency is defined as the simultaneous outage of any two elements selected from the combined set of candidate transmission branches and selected generating units.

To make the post-processing fully reproducible and mathematically explicit, we define the index sets $T = \{1, \ldots, 24\}$ for the hourly operating points, $C = \{1, \ldots, 252\}$ for the contingencies applied at each hour, and S for the four scenarios. The key islanding-related quantities exported from PowerWorld contingency results are Islanded Load (MW) and Islanded Gen (MW), which are directly reported by the software and are therefore not computed manually. In PowerWorld, Islanded Load (MW) is the sum of load that becomes islanded from the rest of the system due to contingency-induced changes in network topology (excluding any load that is explicitly opened as part of the contingency actions), while Islanded Gen (MW) is the analogous sum of generation that becomes islanded due to topological separation (excluding any generator explicitly opened/tripped as a contingency action). These fields therefore quantify the amount of demand and supply that ends up in electrically separated subsystems after the outage.

In the autonomous system studied here, we interpret these quantities as adequacy-relevant indicators because they capture how much load and generation is pushed into islands that are no longer part of the pre-contingency connected system. Since steady-state contingency analysis does not model the dynamic viability of these islands (frequency/voltage control, protection actions, and resynchronization), we use Islanded Load as a conservative screening indicator of potential supply interruption risk under severe disturbances. For each scenario $s \in S$, hour $t \in T$, and contingency $c \in C$, we denote these

outputs as $IslandedLoad_{s,c}(t)$ and $IslandedGen_{s,c}(t)$. The following subsection defines the performance metrics used to evaluate these contingency outcomes.

3.2. Contingency Outcome Metrics

Because island operation can occur under severe disturbances in isolated grids, the analysis explicitly treats islanding as a main outcome metric. For each hour t, the worst islanded load is defined as the maximum islanded load across all contingencies,

$$WorstIslandedLoad_s(t) = \max_{c \in C} IslandedLoad_{s,c}(t), \quad (1)$$

and the worst islanded generation is defined analogously as

$$WorstIslandedGen_s(t) = \max_{c \in C} IslandedGen_{s,c}(t). \quad (2)$$

The system's worst branch loading exceedance per hour is captured through the maximum branch loading exceedance across the contingency set. In the exported CA (Contingency Analysis) outputs, branch loading is represented as a percent (%) relative to the thermal limit. Worst$Branch\%_s(t)$ denotes the maximum branch loading exceedance produced by contingency c at hour t. The hourly worst-case branch loading exceedance is then defined as

$$WorstBranch\%_s(t) = \max_{c \in C} Branch\%_{s,c}(t) \quad (3)$$

Here, $Branch\%_{s,c}(t)$ is reported as the percentage exceedance above the thermal limit (e.g., 0.40 corresponds to 40% above the rating, i.e., 140% of the limit). Values below zero are treated as zero exceedance in the post-processing.

Equivalently, in normalized exceedance form, a contingency and branch-level exceedance can be expressed as Sev% = max (0, LF − 1), where LF is the loading fraction relative to the limit. The present work uses the exported exceedance representation to compute the hourly worst-case indicator above. Assuming (for screening purposes) that the load that becomes islanded is not supplied within the post-contingency time step, an hourly proxy for energy not supplied is calculated from the worst islanded load as

$$Violations_s(t) = \sum_{c \in C} ViolCount_{sc,}(t), \quad (4)$$

and a daily total may be defined as

$$Violations_s^{day} = \sum_{t \in T} Violations_s(t). \quad (5)$$

In addition to the continuous indicators above, we introduce a simple but useful separation between thermal-driven and islanding-driven vulnerability modes. For each hour, we define two binary flags:

$$I_s(t) = 1 * (WorstIslandedLoad_s(t) > 0); \quad (6)$$

$$T_s(t) = 1 * (WorstBranch\%_s(t) > 0), \quad (7)$$

which allow hours to be classified as islanding-only (I_s = 1, T_s = 0), thermal-only (I_s = 0, T_s = 1), or combined stress (I_s = 1, T_s = 1). This classification supports a clearer interpretation of results in autonomous systems, where line overloads and network separation may not occur simultaneously.

The framework described above produces, for each scenario, a complete 24 h profile of thermal stress, islanding severity, and ENS proxy indicators. Together, these outputs

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allow a direct, consistent comparison across the four load–RES combinations. Section 4 presents these results, first examining how thermal loading evolves during the day, then analyzing islanding outcomes, and finally discussing how the two risk channels interact under the most severe operating conditions.

4. Results

The contingency outcomes are compared across the four operating scenarios (Low Load–Low RES, Low Load–High RES, High Load–Low RES, and High Load–High RES) over a 24 h horizon. The analysis focuses on three key worst-case indicators computed hourly: (i) branch loading exceedance (as exceedance above the thermal limit), (ii) worst islanded load, and (iii) worst islanded generation, each defined as the maximum value across the contingency set at each hour. This section presents how these indicators evolve during the day and how they differ between the four load–RES combinations.

Figure 2 shows that thermal stress is clearly scenario-dependent. The High Load–High RES case exhibits the highest thermal loading, remaining close to zero during the early hours and then increasing strongly from midday to evening, reaching a peak of approximately 40% exceedance around hours 20–21, before decreasing late in the day.

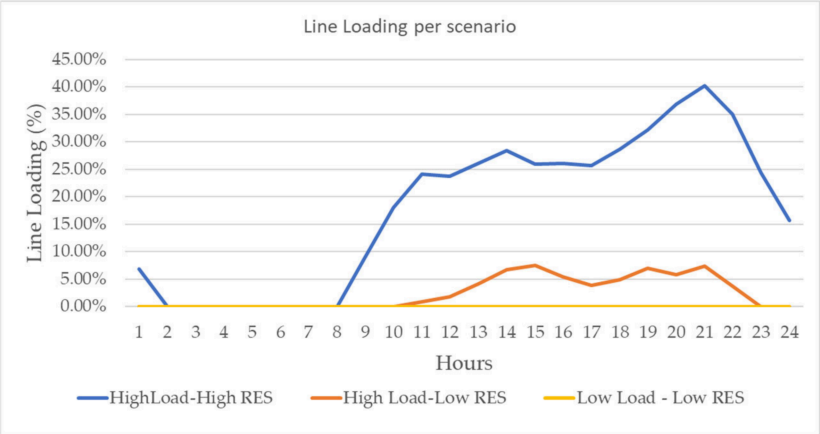


Figure 2. Maximum branch loading exceedance by scenario and hour.

The High Load–Low-RES case shows only mild thermal stress, with a limited time window of non-zero exceedance and a peak below roughly 8%. Under Low Load–High RES, the thermal indicator appears almost flat (showing a persistent, low-level exceedance), suggesting a regime where overload risk is widespread but not extreme. Finally, Low Load–Low RES remains essentially at zero exceedance throughout the day, indicating that thermal limits are not binding in this operating condition.

Figure 3 highlights the adequacy-related impact of contingencies through islanding. The High Load–High RES scenario produces the largest islanding severity, with worst islanded load typically in the range of ~20–31 MW, rising from early hours toward mid-day and staying elevated through the afternoon and evening. In contrast, High Load–Low RES shows zero islanded load across all hours, implying that in this scenario the contingency set does not lead to separation events that disconnect demand. Both low-load scenarios exhibit a constant worst islanded load of about 10 MW, indicating that islanding-related unserved load can persist even when thermal stress is low or absent. This is an important observation because it suggests that islanding is not only a "high-loading" phenomenon. It can also be triggered by network topology and the specific outage combinations.

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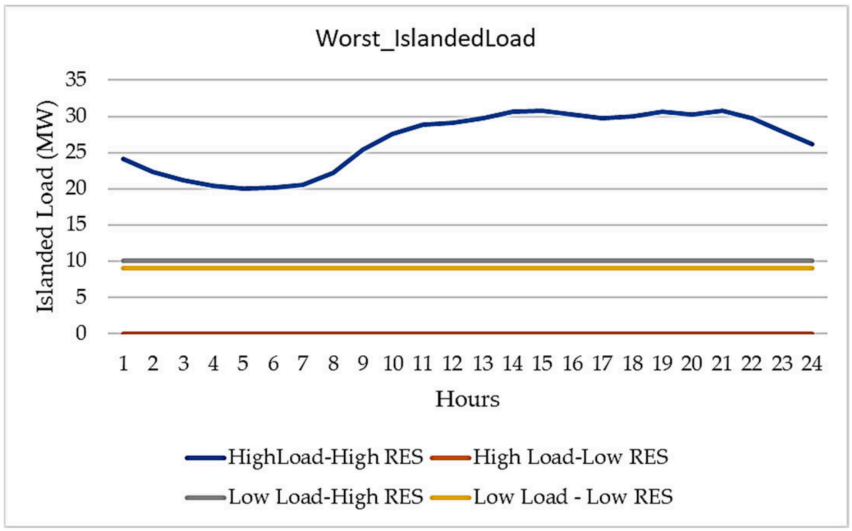


Figure 3. Worst-case islanded load by scenario and hour.

Figure 4 complements the previous findings by showing the amount of generation that becomes electrically separated (islanded) under the worst contingency at each hour. The High Load–High RES case again stands out, with the worst islanded generation roughly ranging from ~50 MW up to ~74 MW, peaking during the late-day period, similar to the thermal loading profile.

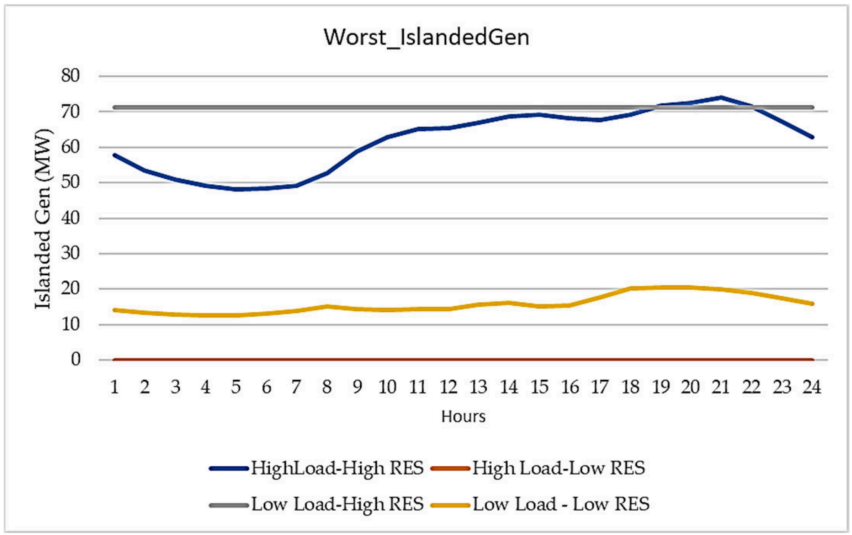


Figure 4. Worst-case islanded generation by scenario and hour.

High Load–Low RES remains at zero, consistent with the absence of islanding as shown in Figure 4. Under Low Load–High RES, the worst islanded generation remains high (around ~70 MW), while under Low Load–Low RES it is much lower (roughly ~12–20 MW). This difference indicates that higher RES availability can lead to a larger amount of generation being trapped inside islands, even when total system demand is low.

The islanding indicators show a different pattern than the thermal loading. High Load–High RES produces substantial islanding impacts, with the worst islanded load peaking at 30.79 MW (hour 14). The corresponding islanded generation is also high, reaching a maximum of 73.97 MW (hour 20). This indicates that severe contingencies under stressed operating conditions can simultaneously lead to (i) non-served demand and (ii) significant generation trapped in electrically separated islands. In High Load–Low RES, islanding

is not observed (worst islanded load and islanded generation remain zero), even though small thermal exceedances can still occur. Under Low Load–High RES, the worst islanded load remains 10 MW across all hours, while the worst islanded generation remains high (up to 71.21 MW), suggesting that island formation can still trap generation even when overall demand is low. Finally, Low Load–Low RES also shows a 10 MW worst islanded load across the day, but with much lower islanded generation (maximum 20.59 MW), indicating a less generation-heavy islanding outcome.

The hourly sum of violations further highlights how often the contingency set produces overload conditions, not only how large the single worst overload is. High Load–High RES accumulates 410 total thermal violations over the day, with the largest hourly violation count reaching 33 (hour 19). High Load–Low RES is much lighter in this sense, with only 24 total violations over the day and a maximum of 2 violations in a single hour. In Low Load–High RES, violations are persistent across the entire day (effectively 21 violations per hour, i.e., 504 total over 24 h), even though the maximum exceedance remains relatively small (7.4%). This combination suggests a regime where many contingencies produce modest overloads rather than a few contingencies producing extreme overloads. In Low Load–Low RES, violations remain zero throughout.

When translating islanding severity into an energy-based indicator, the daily ENS proxy equals the sum of worst islanded load over the day ($\Delta t = 1$ h). High Load–High RES yields the highest ENS proxy of approximately 638.6 MWh/day, while both low-load scenarios yield 240 MWh/day (10 MW $\times$ 24 h) and High Load–Low RES yields 0 MWh/day. This shows that ENS-type impacts are not driven only by peak demand. They also depend on how the operating point and RES pattern interact with the network's ability to remain connected under severe outages.

Figure 5 provides an additional view of ENS proxy behavior across hours, emphasizing that islanding severity is not evenly distributed in time. Instead, the hourly ENS proxy clusters into distinct ranges rather than following a smooth unimodal distribution. Lower ENS ranges (~20–24 MWh) correspond to milder islanding events that occur under less stressed operating conditions, while the concentration of hours in the ~28–32 MWh range reflects recurring severe islanding conditions associated primarily with the High Load–High RES scenario.

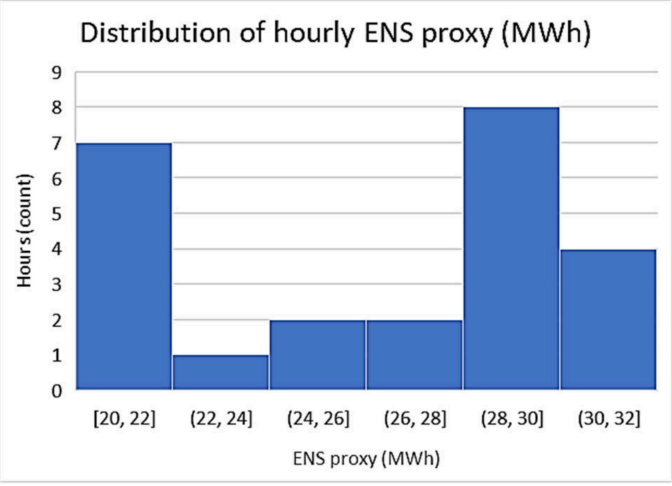


Figure 5. Distribution of hourly ENS proxy by energy range.

The presence of these higher ENS ranges is therefore an indication that the system repeatedly enters operating states where specific N-2 contingencies produce substantial network separation and loss of supply adequacy. This behavior shows the existence of

distinct operational regimes in the autonomous system, such as a lower-severity regime with limited islanding consequences and a higher-severity regime where unfavorable combinations of load level, RES dispatch, and network topology significantly amplify ENS outcomes. The non-uniform distribution further reinforces the idea that contingency vulnerability is strongly time-dependent rather than randomly distributed across the day.

Finally, we examine the relationship between thermal stress and unserved energy as shown in Figure 6. The regression uses the subset of hours with a non-zero ENS proxy (N = 14), thus focusing on operating points where islanding actually occurs. A strong positive association is observed between maximum line loading and ENS proxy, with a coefficient of determination of approximately $R^2 = 0.79$, indicating that hours/operating points with higher thermal stress also tend to produce higher ENS proxy values under contingencies.

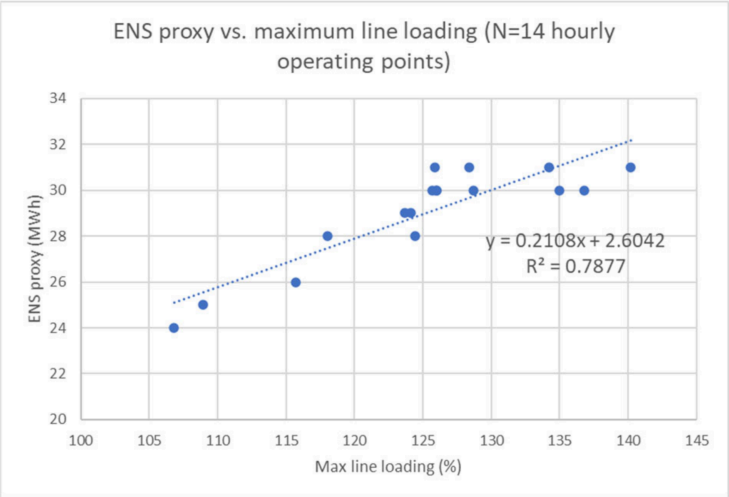


Figure 6. ENS proxy vs. maximum line loading.

5. Discussion

The comparative analysis across the four operating scenarios reveals that system vulnerability in an autonomous island grid is not driven by a single factor—neither load magnitude nor renewable generation level—but by their combined interaction with network topology and the contingency set. These findings challenge simplistic narratives that attribute insecurity solely to "high renewable penetration" or "peak demand periods," demonstrating instead that the timing, location, and composition of generation relative to demand patterns fundamentally shape contingency outcomes.

The High Load–High RES operating condition emerges as the most critical regime, concentrating both thermal stress and islanding severity within the same 24 h period in a distinctly time-dependent manner. The evolution of thermal loading exceedance from near-zero during early hours to peak values approaching 40% in the evening indicates that the system operates progressively closer to its transfer capability as the day advances. This temporal gradient suggests that contingency planning cannot rely on snapshot assessments at a single operating point; rather, the most severe N-2 impacts occur during specific windows when demand, renewable output, and power flow patterns align unfavorably. Critically, these same hours also coincide with sustained islanding severity, demonstrating that thermal and adequacy vulnerabilities can compound under stressed conditions—a result with direct implications for real-time contingency screening and corrective action prioritization.

A key insight from the results is that thermal stress and network separation do not exhibit a deterministic relationship across scenarios. The High Load–Low-RES case produces modest thermal exceedance during certain hours yet exhibits zero islanding throughout

the day, pointing to a vulnerability mode dominated by congestion and thermal constraints without triggering network partitioning. This behavior is consistent with traditional N-2 contingency frameworks that focus primarily on overload management. In stark contrast, both low-load scenarios display persistent islanded load even when thermal exceedance remains negligible or absent. This decoupling reveals that islanding in this system is often topology-triggered rather than congestion-driven: network separation can result from the structural characteristics of the grid and the specific location of cut sets, irrespective of whether line thermal ratings are binding. For autonomous systems, this distinction is operationally critical: islanding directly translates into adequacy impacts (unserved demand) and can simultaneously trap generation, creating isolated subsystems that must either sustain themselves or shed load, with no possibility of external synchronous support.

The behavior under Low Load–High RES conditions offers a particularly instructive physical interpretation of renewable-dominated operation. Despite relatively mild thermal severity, worst-case islanded generation remains elevated across the entire day, suggesting that when generation is spatially dispersed or exceeds local demand, the system becomes prone to forming islands containing significant amounts of active generation. From an operational standpoint, this is problematic: post-contingency power balance and controllability within these islands become inherently more challenging, especially in real systems where frequency and voltage dynamics—neglected in steady-state contingency analysis—govern transient stability and protection coordination. In other words, high renewable penetration does not automatically increase thermal overload risk under low-load conditions, but it may substantially increase the quantity and complexity of generation involved in islanded subsystems, introducing dynamic control challenges that static N-2 screening cannot fully capture.

These findings support a dual-channel interpretation of contingency risk in autonomous island grids. The first channel is thermal security, reflected by branch loading exceedance and violation counts, which becomes most pronounced when the system is heavily loaded and power transfers are high. The second channel is adequacy under network separation, reflected by islanded load and the associated ENS proxy, which can persist even when thermal limits are not binding. Crucially, these two channels do not always activate simultaneously, nor do they exhibit uniform sensitivity to load and RES levels. A contingency framework that evaluates only one channel—for instance, focusing exclusively on thermal violations as in traditional deterministic N-1 criteria—will systematically underestimate operational risk in isolated systems where network partitioning represents an equally severe, yet mechanistically distinct, failure mode.

The practical implication is clear: N-2 contingency assessment for autonomous grids must explicitly account for both thermal violations and islanding outcomes as co-equal metrics of system adequacy and security. Relying on thermal criteria alone may identify overload-driven risks while missing topology-driven separation events, which are just as consequential for supply continuity. Moreover, the time-dependent nature of vulnerability under High Load–High RES conditions underscores the need for dynamic, hour-by-hour contingency evaluation rather than static worst-case assumptions, particularly as renewable penetration increases and operational margins tighten. Future extensions of this work should integrate dynamic simulations to validate whether the identified islands can sustain stable operation or require immediate corrective actions such as controlled load shedding, synthetic inertia provision, or grid-forming inverter coordination.

6. Conclusions

This work presents a 24 h N-2 contingency assessment of a 6-bus autonomous island system with moderate renewable penetration, combining transmission line outages with

generator failures under four load–RES operating scenarios. Three main findings emerge. First, the High Load–High RES scenario exhibits the highest combined thermal and islanding severity, with vulnerability intensifying from mid-day to evening—demonstrating that contingency risk in autonomous grids is both time-dependent and driven by the interaction between load patterns, renewable output, and network topology rather than by any single factor. Second, thermal stress and islanding do not exhibit a deterministic relationship: the High Load–Low-RES case produces thermal violations without network separation, while low-load scenarios exhibit persistent islanded load even when thermal limits are not binding. This decoupling reveals that islanding is often topology-triggered and that relying solely on overload indicators systematically underestimates adequacy risk. Third, higher RES availability under low demand increases the quantity of generation trapped in separated subsystems, introducing operational challenges for post-contingency power balance and control that are not captured by thermal criteria alone.

The deterministic, steady-state nature of this analysis represents a fundamental limitation. Actual post-contingency outcomes in autonomous systems are governed by frequency and voltage dynamics, protection coordination, and transient stability—particularly when network separation occurs. Future work must, therefore, prioritize dynamic validation of the most critical hour–contingency pairs, incorporating frequency nadir, RoCoF (Rate of Change of Frequency), voltage recovery, and realistic load-shedding sequences to replace the ENS proxy with event-based EENS estimates that account for island power balance and available reserves.

A second essential direction is the transition from severity-only assessment to a risk-based framework that incorporates contingency likelihood, enabling EENS-weighted or violation-weighted risk indices. This requires robustness testing across seasonal and uncertainty-aware RES/load ensembles, rather than relying on single representative days. Finally, since islanding can occur independently of thermal stress, explicit identification of critical cut sets through graph-based or flow-based ranking is necessary, followed by evaluation of targeted mitigation strategies—including controlled islanding, grid-forming inverter deployment, and security-constrained corrective optimization that quantifies the trade-off between contingency mitigation and operational cost.

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