Engineering and Technology Journal e-ISSN: 2456-3358
Volume 11 Issue 09 September -2026, Page No.- 11491- 11498
DOI: 10.47191/etj/v11i09.11, I.F. – 8.595

A Reliability-Centered Approach to Preventive Maintenance (RCM) Evaluation of an 11/0.415 Kv Secondary Distribution Substation

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ABSTRACT: This study conducts a detailed a Reliability-Centered Approach to Preventive Maintenance (RCM) evaluation of an 11/0.415 kV secondary distribution substation using actual 2024 operational failure data comprising 187 recorded component failures and 1,003 outage hours across eleven major equipment categories. Reliability indices—failure rate, Mean Time between Failures (MTBF), and Mean Time to Repair (MTTR) were computed for each component. The fuses, transformer, switchgear, and outgoing feeders were identified as the most critical assets, together accounting for over 80% of total failures and approximately 85% of total outage duration, thereby forming the basis for RCM prioritization.

A Monte-Carlo simulation with 10,000 iterations was employed to evaluate three maintenance strategies: Reactive maintenance, Annual Preventive Maintenance for all components, and an RCM-based strategy targeting only the top three most critical components. The Reactive policy produced the highest annual outage duration, with an average of 1019.31 hours, corresponding to a system availability of 88.36%. Implementing Annual Preventive Maintenance across all components resulted in a significant reduction in expected outage hours to 553.64 hours, improving availability to 93.68%. The RCM-Top3 strategy, which applied preventive actions only to the transformer, switchgear, and outgoing feeders, achieved an average outage duration of 627.78 hours and availability of 92.83%, while requiring 73% fewer preventive maintenance actions compared to the full preventive maintenance plan.

The results demonstrate that preventive maintenance substantially improves substation reliability, and that an RCM-based prioritization approach delivers a favorable balance between reliability improvement and maintenance resource utilization. The study highlights the value of data-driven maintenance planning in power distribution networks, especially in resource-constrained environments. Future work should incorporate multi-year failure modeling, cost-benefit analysis, and optimization of preventive maintenance intervals to further enhance asset management strategies.

KEYWORDS: Armature Current, Separately Excited DC Motor, Transient Response. MATLAB/Simulink, Feedback Control.

I. INTRODUCTION

Ensuring reliable electricity supply is critical for economic and social development particularly in distribution networks that deliver power directly to end-users. Distribution substations, such as 11/0.415 kV secondary substations, play a central role in stepping down voltage and distributing power safely and reliably to consumers [1]. However, components in these substations (transformers, switchgear, protection devices, busbars, etc.) undergo aging, wear, and degradation over time, which increases the risk of failures, outages, and costly maintenance or replacement [2] [3].

Traditional maintenance strategies often reactive (fix-after-failure) or strictly time-based preventive maintenance may fail to optimize the trade-off between reliability, cost, and resource constraints [4] [5] [6]. Reactive maintenance leads to unplanned outages and often high downtime costs, while periodic time-based preventive maintenance can result in unnecessary maintenance actions, inefficient allocation of resources, or premature maintenance on components that are not failing. But, recent researches frames the maintenance problem as an optimization of trade-offs among (i) reliability (outage frequency and duration), (ii) maintenance and replacement cost, and (iii) service penalties or customer interruption costs which is a multi-objective decision space where data-driven, risk-informed policies outperform rigid periodic schedules [7] [8]

In order to address these shortcomings associated with the traditional maintenance strategy, modern asset management in power distribution networks increasingly employs a more systematic, data-driven, risk- and reliability-based maintenance philosophy [9]. This is what this research offers, with the aim to develop and apply a Reliability Centered Maintenance (RCM) based preventive maintenance evaluation methodology for an 11/0.415 kV secondary distribution substation, with the goal of optimizing maintenance actions to improve reliability and minimize costs.

II. RESEARCH PROBLEM

Despite the proven benefits of RCM in distribution networks, there remains omissions in the literature when it comes to applying RCM specifically to secondary distribution substations (e.g., 11/0.415 kV), particularly in developing-country contexts (such as Nigeria) where network conditions, funding constraints, and asset conditions are often more challenging [10] [11]

Several previous studies focus on overhead lines, feeders, or general distribution network components; fewer systematically assess substation-level assets (transformers, switchgear, protection, busbars) under an RCM framework. Without substation-level RCM-based maintenance plans, utilities are at risk of either over-maintaining (wasting limited resources) or under-maintaining (leading to outages, reliability issues).

Given the important role of secondary substations in power delivery, a well-structured RCM evaluation tailored to substation assets, their failure modes, their criticality, and maintenance cost constraints can significantly enhance overall network reliability, reduce outages, and improve cost-effectiveness.

III. LITERATURE REVIEW

Overview of Maintenance Strategies in Power Systems

Maintenance strategies in power systems generally fall into reactive (run-to-failure), preventive (time-based or periodic), predictive/condition-based, and reliability-oriented approaches. As demand for reliable supply increases while asset aging and budget constraints challenge utilities, reactive maintenance becomes increasingly untenable. Corrective approaches may lead to unplanned outages, asset damage, and high downtime costs. Meanwhile, naive periodic preventive maintenance can lead to inefficient resource use and unnecessary maintenance actions. Accordingly, modern practice and research increasingly favour maintenance strategies that are data-driven, risk-informed, and context-sensitive [12].

The concept of maintenance has thus evolved towards systematic, reliability and risk-based frameworks, where maintenance tasks are selected and scheduled based on probability of failure, consequences, asset criticality, and cost–benefit trade-offs, rather than simply on elapsed time or arbitrary intervals [13].

In the context of distribution networks (which include feeders, lines, cables, substations, transformers, switchgear, protection devices, etc.), the complexity and heterogeneity of assets especially at the substation level make a strong case for tailored, prioritized maintenance programs rather than blanket maintenance for all assets. This motivates the use of a more refined maintenance philosophy such as reliability-centered maintenance (RCM).

Reliability-Centered Maintenance (RCM)

Reliability Centered Maintenance (RCM) is a structured maintenance philosophy that aims to preserve system functions rather than simply maintain components on an arbitrary schedule. Under RCM:

1. One identifies what functions each asset must fulfill.
2. For each function, potential failure modes are identified along with their causes and likely consequences (impact on safety, reliability, cost, downtime, etc.).
3. Failure modes are evaluated in terms of risk (probability and consequence), detectability, and whether preventive or mitigating maintenance actions make sense.
4. Maintenance tasks are then selected that target the dominant failure causes, aiming for cost-effectiveness and optimal risk reduction.
5. The maintenance plan is periodically reviewed and updated based on operational feedback and condition data.

Thus, RCM moves beyond fixed-interval preventive maintenance to a function-based, consequence-driven, and often condition-aware maintenance strategy. The standard process logic helps ensure that maintenance resources are applied where they yield the greatest reliability benefit for cost and risk exposure.

Advantages of Reliability-Centered Maintenance (RCM)

Reliability centered maintenance has advantages which include the following:

1. Resource optimization: By focusing only on critical components and high-risk failure modes, RCM helps allocate maintenance budget more effectively rather than spreading resources thinly over all assets.
2. Reduced unplanned outages: Since RCM intends to anticipate and prevent failure before it happens (through preventive or predictive tasks), the frequency and severity of unplanned outages decreased
3. Flexibility & adaptability: Maintenance plans can evolve as more data (failures, condition monitoring and operational history) becomes available, giving room for plans to be refined.
4. Function & safety focused: RCM emphasizes preserving the primary and secondary functions of assets (supply, protection, and safety), including those whose failures could lead to severe consequences.

Challenges / Limitations of Reliability-Centered Maintenance (RCM)

Despite the advantages that are associated with RCM, it is also characterized with some challenges and limitations such as:

1. Lack detailed or inadequate data: Effective RCM relies on good historical failure data, maintenance logs, condition-monitoring capabilities, and accurate estimation of failure probabilities and consequences. In most utilities particularly in developing-country contexts, such detailed data may be lacking or incomplete.

2. Complex analysis: For systems with many asset types (like substations), RCM requires detailed function analyses, identification of many failure modes, risk assessment, and maintenance planning, which can be time-consuming and require skilled personnel.
3. Implementation inertia / organizational culture: Moving from periodic or reactive maintenance to RCM often demands organizational commitment, training, and possibly new tools (databases, CMMS, condition monitoring). Some organizations may resist this due to inertia or lack of awareness.

Reliability Assessment & Modeling Techniques for Power Systems

In order to support RCM, and to quantify the benefits of preventive maintenance plans, it is often necessary to perform reliability assessment and modeling. Recent literature highlights several prominent methods and combinations thereof:

Analytical Methods: Analytical methods such as reliability block diagrams (RBD), fault tree analysis (FTA), Markov models, hazard/failure-rate models for individual components or subsystems have been employed

Simulation-Based Methods: Simulations based methods such as: Monte Carlo simulations, sequential simulations, stochastic simulations based on historical failure/repair data, useful when system complexity or lack of closed-form analytical solution have been used [14] [15]

Hybrid Methods: This involves combining analytical and simulation methods, or combining failure-mode assessment with probabilistic modeling (e.g., combining FMEA/FMECA results with hazard rate modeling), to leverage both qualitative insight and quantitative reliability metrics.

Additionally, advanced frameworks now combine reliability modeling with condition-based maintenance for high-value assets like transformers, where condition monitoring (oil analysis, partial discharge, temperature, and vibration) can inform maintenance timing, possibly extending life and reducing cost compared to rigid periodic maintenance. Furthermore, recent review highlights that computational maintenance planning which integrates reliability modeling with cost, interruption risk, and resource constraints is increasingly being adopted for distribution networks (especially with the emergence of smart-grid technologies).

Failure Mode Analysis Using Traditional FMEA / FMECA

Failure Mode and Effects Analysis (FMEA) or its extension Failure Mode, Effects and Criticality Analysis (FMECA) remains one of the most widely used tools in reliability engineering and maintenance planning. In FMEA / FMECA, each component (or function) is analyzed to list possible failure modes, causes, and effects; then, risk scores (e.g., Risk Priority Number, RPN) are assigned based on severity, occurrence (likelihood), and detectability (or lack thereof), often via a numeric scale. The output helps identify which failure modes are "critical" (high severity, high probability and low detectability) and therefore require preventive or mitigative action.

In power systems equipment (including substations, transformers, transmission lines, switchgear), FMEA/FMECA is applied to identify potential failure modes (e.g., insulation breakdown, contact wear, relay fail, bus fault, transformer overloading, etc.) and to guide maintenance resource allocation.

Limitations of Traditional FMEA / FMECA for Power Systems

Although, FMEA/FMECA is useful, it has recognized limitations, especially when applied in isolation or with simplistic assumptions. They include:

Static view: Traditional FMEA assumes fixed probabilities and does not account for changing failure rates over time or as assets age. Thus, it may not prioritize maintenance if an asset's failure rate increases non-linearly with age or usage.

Subjectivity/uncertainty: Severity, occurrence and detectability scores often rely on expert judgement, which may be inconsistent, subjective, or biased, especially in absence of detailed failure data. This can lead to poor or non-robust prioritization.

Lack of quantitative reliability metrics: FMEA / FMECA alone does not provide probability distributions, failure rates, MTBF/MTTR, or system-level reliability indices (availability, interruption frequency/duration) unless combined with reliability modeling.

Failure Mode Analysis Using Time-Dependent and Fuzzy Methods

To overcome the shortcomings of classical FMEA/FMECA, more recent studies propose modifications by integrating time-varying failure probability into the FMEA framework, recognizing that failure likelihood changes over life-time (aging, wear, environmental stress [16] [17]

Fuzzy-based FMEA / FMECA has been proposed in order to reduce subjectivity and handle uncertainty in severity, occurrence, and detectability assessments. Applying fuzzy logic (or other soft-computing techniques) to represent risk factors as fuzzy sets rather than crisp numbers, helps in generating more reliable prioritization under ambiguity. These enhancements of FMEA/FMECA make it more suitable for complex, real-world systems like distribution substations or smart grids, where variation, uncertainty, and limited data are common.

IV. METHODOLOGY

This chapter describes how the FMEA, reliability metrics, maintenance-scheduling decisions, and simulation analyses are constructed and computed from the substation's failure data.

Data preparation and assumptions

The dataset of the study case distribution substation (Elele 11/0.415 kV Substation) collected from Port Harcourt Electricity Distribution Company (PHEDC) (Elele

Business Unit), covers January–December 2024 and lists, per component, the yearly number of failures and total outage hours is as shown in Table 1

Table 1: Annual Summary of Component Failure and Duration

Component	Total Failures	Total Outage Hours
Transformer	27	463
Switchgear	37	77
Supply line	19	70
Busbars	4	20
Circuit breakers	6	25
Fuses	54	186
Switches	4	16
Outgoing feeder	39	157
Overcurrent Relay	2	3
Earth Fault Relay	1	2
Surge Arrester	0	0

Source: PHEDC (2024)

Assumptions Made:

1. One year is assumed to be 8,760 hours (non-leap year). Operational time for each component is taken as 8,760 hours (continuous availability outside outages).
2. For components with zero failures in the year, rate estimates are not directly computable; we treat MTBF as undefined (or infinite) and report zero observed failure rate. For reliability modeling (simulation), a small nonzero conservative rate can be assumed if needed (e.g., Bayesian prior), but any assumption will be stated.
3. Failure process: Poisson process (i.e., exponential interarrival times) with constant hourly rate
4. Repair times: modeled as exponential with mean equal to observed MTTR (total outage hours ÷ failures).
5. Preventive maintenance (PM) model: one PM action per scheduled component at the start of the year, which (i) reduces the component failure rate by 50% for the remainder of the year (a conservative effectiveness assumption), and (ii) causes an immediate PM downtime of 4 hours per component. PM cost is not included in this simulation; only downtime and reliability metrics are evaluated.
6. RCM prioritization: composite criticality index (CCI) = 0.5 x (normalized annual failures) + 0.5 x (normalized annual outage hours). Top-3 components by CCI receive PM in the RCM-Top3 policy.
7. Number of Monte-Carlo runs: 10,000 to estimate distributions and confidence intervals

Key Metrics Used: Calculations Applying Analytical Techniques

Annual Failure Rate

The annual failure rate represents the expected number of failures of a component or system within one calendar year. It is a fundamental reliability index used to quantify how frequently equipment fails during operation

$$\lambda_{year} = N \quad \text{(failure/year)} \qquad (1)$$

$$\text{Failure rate per hour} = \lambda = \frac{N}{T_{year}} \quad \text{(failure/hour)} \qquad (2)$$

Where:

N = number of failures observed in one year (dimensionless)

T_{year} = 8,760 hours

λ = constant failure rate

Mean Time Between Failures (MTBF)

The Mean Time Between Failures (MTBF) is the average operational time between successive failures of a component. It is inversely related to the failure rate and is commonly used to assess the inherent reliability of equipment. Assuming exponential failure distribution.

$$\text{MTBF} = \lambda = \frac{1}{\lambda} = \frac{T_{year}}{N}, \ N > 0 \qquad (3)$$

Where:

MTBF is measured in hours

Mean Time To Repair (MTTR)

The Mean Time to Repair (MTTR) defines the average time required to restore a component after failure. It is expressed as:

$$\text{MTTR} = \frac{H_{Out}}{N}, \ N > 0 \qquad (4)$$

Where:

MTTR is measure in hours

H_{Out} = total outage hours in one year

Component Availability (steady state approximate)

Component availability is the probability that a component is operational and capable of performing its intended function at any given time. It is widely used as a performance metric in reliability-centered maintenance studies.

$$A \approx \frac{\text{MTBF}}{\text{MTBF} + \text{MTTR}} \qquad (5)$$

Where:

A ranges between 0 and 1 and it is dimensionless

Component Unavailability (Steady state approximate)

Component unavailability represents the fraction of time a component is in a failed or non-operational state. It is calculated using the failure rate and repair time, providing insight into how often a component contributes to system downtime.

Using failure rate and repair time,

$$U \approx \lambda \times \text{MTTR} \qquad (6a)$$

Using MTBF and MTTR

$$U \approx \frac{MTTR}{MTBF + MTTR} \quad (6b)$$

Where:

$U = 1 - A$

Expected Number of Failures Per Year

The expected number of failures per year represents the statistical expectation of how many failure events occur annually. This metric is essential in Monte Carlo simulation, where it serves as a probabilistic input for modeling system behavior under different maintenance strategies. The expected number of failures over a time interval T (hours), assuming a constant failure rate (λ):

$$E[N(T)] = \lambda T_{year} \quad (7a)$$

For one year:

$$E[N_{year}(T)] = \lambda T_{year} \quad (7b)$$

Reliability Function R (t)

The reliability function, R(t) represents the probability that a system or component will perform its intended function without failure over a specified time interval t. It is a time-dependent measure that quantifies the survival likelihood of equipment under normal operating conditions. Probability the component survives a duration t without failure:

$$R(t) = e^{-\lambda t} \quad (8)$$

System Availability for Series System of Components (approximation)

For a series system, where all components must be operational for the system to function, the system availability is determined by the combined availability of each individual component. Because the failure of any single component results in system downtime, the overall system availability is lower than that of its individual components. For a system composed of n independent components connected in series, where failure of any component causes system failure, the system availability (approx, steady-state) is:

$$A_{system} = \sum_{i=1}^{n} Ai \quad (9)$$

Where:

Ai = steady –state availability of component i

Note: Equation (9) assumes statistical independence and constant steady-state availability

Customer Interruption Contribution (CIC)

The Customer Interruption Contribution (CIC) quantifies the extent to which a particular component contributes to customer interruptions. It considers failure rate, outage duration, and the number of customers affected, making it a key parameter for identifying critical components in reliability-centered maintenance analysis. CIC is formulated as:

$$CIC_i = \lambda_i \ x \ MTTR_i \ x \ C_i \quad (10a)$$

Alternatively, in annual form:

$$CIC_i = N_i \ x \ MTTR_i \ x \ C_i \quad (10b)$$

Where:

CIC_i = is the measure in customer hours/year

λ_i = failure rate of component i (failure/hour)

$MTTR_i$ = mean repair time of component i(hours)

C_i = number of customers affected by component i

FMEA and Criticality Ranking Procedure

For FMEA and Criticality Ranking, a hybrid criticality assessment approach that integrates qualitative Failure Modes and Effects Analysis (FMEA) with quantitative reliability for substation components was used. Each component, potential failure modes and their effects are identified using historical maintenance records and expert judgment. Each failure mode is evaluated using severity (S), occurrence (O), and detectability (D) indices on a standard ten-point scale, from which the Risk Priority Number (RPN) is calculated. The RPN is combined with measured operational indicators such as component failure rate, outage duration, and mean time to repair, and cost impact into a Composite Criticality Index (CCI). The CCI provides a ranked list of components, enabling focused reliability-centered maintenance planning

Monte Carlo Simulation Framework

Monte-Carlo simulation implemented in MATLAB is used to evaluate maintenance strategies under uncertainty. Component failures are modeled as Poisson processes using observed failure rates, with optional probabilistic modeling of parameter uncertainty. Repair times are sampled from appropriate statistical distributions based on mean time to repair. Maintenance policies reactive, periodic preventive, condition-based, or RCM-prioritized are applied within the simulation. To evaluate policies under uncertainty, Monte-Carlo simulation was performed these plan:

1. For each component, observed λ was used
2. Simulation done for horizon T (e.g., 1 year) in small time steps (e.g., 1 hour). For each realization. Simulation of failures as Poisson process with rate λ, sample repair times from distribution with mean MTTR (e.g., exponential).
3. Applying maintenance policy rules (reactive, All PM at interval, RCM prioritized PM) and track metrics: number of failures, total outage hours, availability..
4. Repeat N runs (e.g., N = 10,000) to obtain distributions of outcomes and confidence intervals.

V. RESULTS AND DISCUSSIONS

Component Criticality and Reliability Metrics

Table 2 summarizes the reliability attributes of major distribution network components, including failure rate, MTBF, MTTR, and steady-state availability. The composite criticality analysis identifies the transformer, switchgear, and outgoing feeder as the three most critical components, consistent with their relatively high failure frequency and contribution to outage duration. The

transformer exhibits the highest unavailability (≈0.053) and a comparatively short MTBF (≈324 h), confirming its dominant influence on overall system downtime. The switchgear also records a high failure rate but maintains a much shorter MTTR, resulting in higher availability relative to the transformer. The outgoing feeder ranks highly due to a combination of moderate MTBF and restoration duration, leading to appreciable outage impact.
These results justify the RCM-Top3 prioritization strategy, as the top-ranked components not only fail more frequently but also account for a disproportionate share of outage hours. Focusing maintenance resources on these high-impact assets is therefore expected to yield significant reliability improvement while minimizing maintenance cost and effort

Table 2: Component Criticality and Reliability Metrics

Component	Failure Rate (per hour)	MTBF (hours)	MTTR (hours)	Availability (approx)	Unavailability (approx)
Transformer	0.003082	324.4	17.15	0.9498	0.052854
Switchgear	0.004224	236.8	2.08	0.9913	0.008790
Supply line	0.002169	461.1	3.68	0.9921	0.007991
Busbars	0.000457	2190.0	5.00	0.9977	0.002283
Circuit breakers	0.000685	1460.0	4.17	0.9972	0.002854
Fuses	0.006165	162.2	3.44	0.9792	0.021233
Switches	0.000457	2190.0	4.00	0.9982	0.001826
Outgoing feeder	0.004452	224.6	4.03	0.9824	0.017922
Overcurrent Relay	0.000228	4380.0	1.50	0.9997	0.000342
Earth Fault Relay	0.000114	8760.0	2.00	0.9998	0.000228
Surge Arrester	0.000000	—	—	—	—

Mean Outage Hours for Each Maintenance Policy
Figure 1 is a bar chart that compares the average annual outage hours obtained from the 10,000-run Monte Carlo simulation for the three analyzed maintenance strategies. The Reactive maintenance policy produces the highest outage hours, with an average of 1019.31 hours/year, indicating the largest exposure to failures and long restoration durations. This is expected because components are only attended to after failure, allowing degradation to accumulate unchecked.
The AnnualPM_All strategy shows a substantial improvement, reducing expected annual outage hours to 553.64 hours, representing approximately a 45.7% reduction relative to the reactive policy. This demonstrates the effectiveness of scheduled preventive maintenance in limiting both failure occurrence and restoration durations.
The RCM_Top3 strategy produces 627.78 hours of expected outage time, which is higher than full preventive maintenance but still 38.4% lower than the fully reactive case. Despite requiring far fewer maintenance resources, RCM_Top3 still delivers a strong improvement, validating the importance of focusing on critical components.

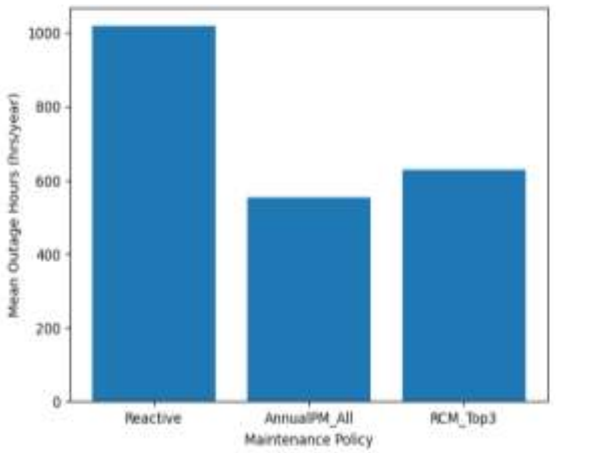

Figure 1: Plot of Mean Outage Hours for Each Maintenance Policy

Mean Availability for Each Maintenance Policy
Figure 2 is a bar chart illustrating the mean availability for all the three maintenance policy.The plot shows that the Reactive policy yields the lowest system availability at 0.8836, corresponding to about 322 hours/year of expected unavailability. The low availability reflects the cumulative effect of high failure rates and long downtime.
The highest availability value is associated with AnnualPM_All (0.9368), highlighting that routine preventive maintenance significantly enhances system performance by preemptively addressing degradation mechanisms.
The RCM_Top3 strategy achieves 0.9283 availability, only slightly lower than full preventive maintenance. This result shows that performing maintenance selectively on the most reliability-critical components captures most of the benefit of full system-wide preventive maintenance while using fewer resources.

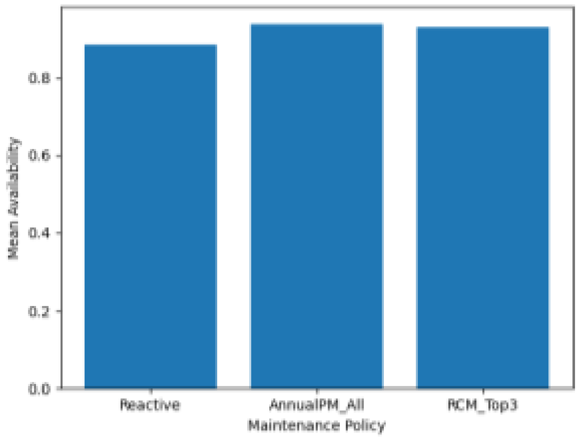

Figure 2: Plot of Mean Availability for Each Maintenance Policy

Mean Number of Failures Per Year for Each Maintenance Policy

Figure 3 is a bar chart that compares the average number of failures expected annually under the different maintenance strategies. The Reactive strategy records the highest value, with approximately 192.92 failures/year, consistent with its lack of pre-failure interventions.

The Annual PM All strategy reduces failures to 96.53 per year, cutting the failure count by almost 50%. Preventive maintenance significantly delays or eliminates failure occurrence by addressing wear-out and early degradation.

The RCM Top3 approach results in 132.95 failures/year, which falls between the other strategies. This again reflects the selective nature of RCM maintenance—focusing on critical components prevents many systemic failures but cannot prevent all failures across non-critical equipment.

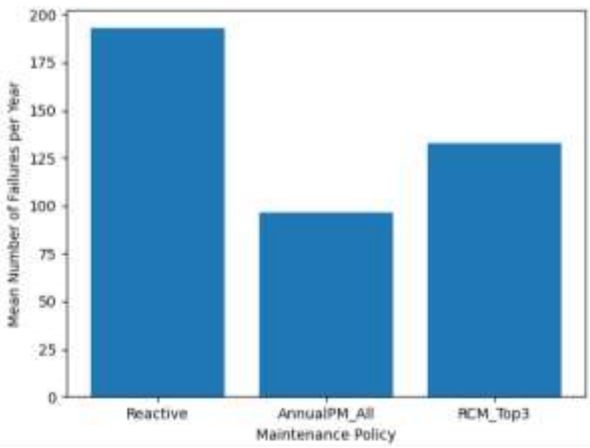

Figure 3: Plot of Mean Number of Failure Per Year for Each Maintenance Policy

VI. CONCLUSION

This study conducted a comprehensive Reliability-Centered Preventive Maintenance (RCM) assessment of an 11/0.415 kV secondary distribution substation using real operational failure records and probabilistic simulation techniques. The analysis addressed failure frequency, outage duration, component criticality ranking, and the quantitative impacts of different maintenance strategies on system reliability and availability.

The observed failure data revealed that a small subset of components—including the transformer, switchgear, outgoing feeder, and fuses—accounted for a disproportionately large share of total breakdowns and outage hours. The computation of key reliability indices (failure rate, MTBF, MTTR, availability and unavailability) confirmed that the existing reactive maintenance practice results in elevated downtime and inefficient use of maintenance resources. These findings established the foundation for applying RCM principles, where maintenance actions are prioritized based on component criticality rather than uniform scheduling.

Monte-Carlo simulations were performed to evaluate the reliability impact of three maintenance strategies: the baseline reactive maintenance policy, annual preventive maintenance applied to all components, and a targeted RCM-based preventive maintenance applied to only the three most critical components. Simulation results showed that the reactive policy produced the highest average annual outage hours (≈1019 hours) and the lowest availability (≈88.36%). Implementing preventive maintenance on all components significantly reduced downtime to ≈554 hours and improved availability to ≈93.68%. The RCM-based strategy, which applied preventive maintenance only to the top three critical components, produced a substantial improvement—reducing outage hours to ≈628 and raising availability to ≈92.83%—despite using far fewer maintenance resources.

Overall, the findings demonstrate that preventive maintenance is highly effective in improving distribution substation reliability, and that RCM-based prioritization provides an optimal trade-off between reliability performance and maintenance effort. While annual PM for all components offers the greatest reduction in downtime, the RCM-Top-3 strategy achieves nearly comparable availability improvements with significantly lower maintenance requirements. This highlights the practical value of RCM in resource-constrained environments, such as distribution utilities in developing regions.

The study emphasizes the importance of data-driven decision-making for maintenance planning in power distribution systems. To further strengthen reliability outcomes, future work should include cost-benefit analysis of maintenance actions, incorporation of multi-year failure data to refine statistical models, and integration of more realistic failure-time distributions such as Weibull. Additionally, extending the model to include economic interruption costs and optimized maintenance intervals would provide utilities with a holistic framework for reliability-centered asset management.

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