A Practical Framework for Reliability Assessment in Transmission Systems

M Al Mamun, Kishan Prudhvi Guddanti, Alexandre B. Nassif, Alok Kumar Bharati, Patrick Maloney, Marcelo Elizondo
Pacific Northwest National Laboratory
Richland, WA, USA

Email: {mal.mamun, kishan.g, alexandre.nassif, ak.bharati, patrick.maloney, marcelo.elizondo}@pnnl.gov

Oscar D. Garzon Rivera, Daniel Haughton, Estefania Alfaro Mejia, Taisha Rosa Ramirez
LUMA Energy
San Juan, PR, USA

Email: {oscar.garzon, daniel.haughton, estefania.alfaromeji, taisha.rosa}@lumapr.com

***Abstract*— Transmission planning practices must benefit from practical reliability assessment methods. This paper introduces an industry-oriented reliability analysis considering practical aspects such as inclusion of non-consequential load-at-risk (LAR), post-contingency generation redispatch reflecting governor behavior, and breaker-to-breaker line configurations governing contingency design. Non-consequential LAR is determined by iteratively solving an optimal power flow in conjunction with the AC power flow model with the objective of minimizing the post-contingency network security violations. The proposed framework is applied to determine the reliability of Puerto Rico transmission system in terms of LAR and expected energy not served (EENS). The effectiveness of the proposed reliability framework is evaluated by benchmarking the current grid against a future, post-investment grid. The future system is implemented with the deployment of the improvements contained in the System Improvements Plan (SIP) and the FEMA Integrated Resilience Plan, which incorporates Hazard Mitigation projects under FEMA Section 406.**

***Index Terms*—Reliability Analysis, AC Contingency Design, Expected Energy Not Served, Remedial Action Schemes.**

I. INTRODUCTION

Power systems may experience both planned or unplanned outages due to various contingencies, such as line, transformer or generator tripping. These contingencies can result in thermal overloads or voltage violations, in turn exposing the system to a risk of load shedding. In extreme cases, system security violations can increase the likelihood of cascading failures. To reduce the risk of load drops, power systems are generally designed to withstand a broad spectrum of operating conditions and probable contingencies, while maintaining operational constraints. Contingencies may have a critical impact on the loads served, and AC Contingency Calculation (ACCC) needs to be carried out to analyze the impact of each contingency. As per the North American Electric Reliability Corporation (NERC) transmission planning requirements [1], the system must remain secure for various types of N-1 and N-1-1 contingencies. In this work we analyze P1, P2, P4, and P7 contingencies (N-1), but similar analysis can be extended to N-1-1 (P3 and P6), which require system information beyond the scope of this paper.

Existing literature has focused on applying various methods to enhance transmission planning and operation, but they all have limitations. Reference [2] suggests adopting evolutionary algorithms to analyze blackouts and their randomness. Other authors have employed Random Chemistry [3] to determine a minimal set of critical contingencies that could trigger large cascading blackouts. The authors of [4] identified a list of contingencies based on stochastic topological configuration of substations and probabilistic failure dataset of protection systems. More recently, [5] introduced a micro-genetic algorithm optimization method to determine corrective actions under contingency. The authors of [6] proposed an optimization-based method to minimize EENS in transmission expansion planning. Lastly, [7] explored the use of DER to reinforce the grid against cyber-attacks.

A common theme of all these papers is that none of them incorporates practical aspects of reliability analysis, utilizing very simple systems that are not constrained by such aspects. Hence, they are all overly academic and impractical to transmission planners. All existing references designed their contingencies by using model branches, rather than a breaker-to-breaker (B2B) line tripping to represent real line operation. Another drawback is ignoring post-contingency generation redispatch. A third drawback is that the current practice of evaluating load-at-risk (LAR) lacks a temporal aspect, i.e., mean-time-to-repair (MTTR) and probability of occurrence. The last aspect of power system operation frequently ignored includes de-rating practices.

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To address these limitations, this paper introduces a practical reliability assessment framework that incorporates reliability standards, industry best practices, and real operational constraints. The main contributions are:

- Modeling of N-1 line contingencies as B2B to model real line configuration and accurately calculate the flows during the post contingency stage.
- Inclusion of governor-based power flow post-contingency redispatch to represent real generator settings and resolve load-generation imbalances.
- Incorporation of de-rating practices into LAR and EENS calculations – this is covered in the case study.
- An iterative OPF and AC power flow methodology to perform system adjustments such as switching shunts, generator redispatch, curtailment, and finally load shedding to alleviate post-contingency violations.
- A unified solution to benchmark the benefits of grid investments using EENS and LAR.

II. Practical Aspects of Transmission Planning

This section illustrates the breaker-to-breaker line and load drop definitions, as well as describes the algorithms to determine LAR and EENS.

A. Breaker-to-breaker Contingencies

When evaluating the impact of a transmission line contingency, the line must be removed entirely (from both terminal stations that contain breakers and relays). While this may seem obvious, it is very challenging to ensure this is the case, as most transmission operators do not model breakers and relays in their load flow simulations. For this reason, most transmission operators struggle to represent entire line contingencies, either creating and maintaining contingency files that need to be manually updated, or simply removing branches rather than entire lines. However, removing branches results in counting multiple times the impact of almost all contingencies, corrupting the analysis. Furthermore, the difference between B2B and individual branches can result in different line flows, causing the system state to deviate far away from the real-world post contingency operating condition.

B. Consequential Load Drop

When a contingency occurs on a particular line, loads directly connected to that transmission line or in a downstream radial feeder get directly impacted and unserved, as illustrated in Fig. 1 (green and red squares represent open and close status, respectively). This LAR is deemed consequential [8].

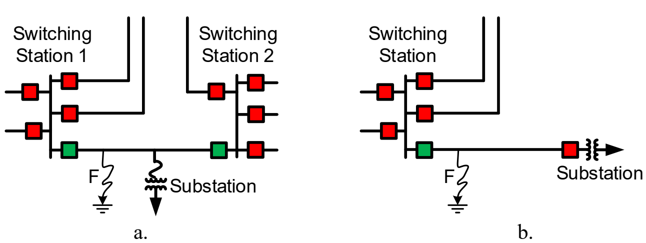

Figure 1. Consequential load shed due to (a) T-Tap line fault, and (b) a radial supply fault

C. System Adjustments Using Optimal Power Flow

Non-consequential load drops, as defined in [8], are usually considered when developing Remedial Action Schemes (RAS). These load drops are not a direct result of an electrical path interruption, such as explained in Fig. 1, but rather an indirect load drop as explained in Fig. 2, which illustrates the concept of non-consequential load drop. Utilities use several methods to create their RAS and usually rely on customer and generation (confidential) information. In this paper, for the purpose of assessing new infrastructure projects, the authors employ an optimal power flow-based scheme to (optimally) adjust load served and remove system violations.

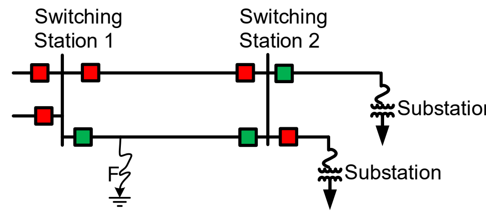

Figure 2. The concept of non-consequential load shed after corrective action.

To achieve this, corrective actions are performed to adjust the control variables to avoid any operational limit violations (e.g., voltage or line thermal overload) caused by any unplanned contingency. The controls considered in this work are switched shunts, LTC tap settings, generator redispatch, and load shedding. The objective of the OPF is to minimize the control adjustments, subject to the power-balance equality and inequality constraints coming from control limits on generator output, LTC tap position, switched-shunt, and operational limits on system bus voltage and branch overflow. The optimization problem is defined as follows:

Minimize: $$\sum_{i=1}^{n} c_i u_i \tag{1}$$

Subject to: $$y(u, v) = 0 \tag{2}$$

$$\underline{v} \leq v \leq \overline{v} \tag{3}$$

$$\underline{u} \leq u \leq \overline{u}, \tag{4}$$

were c is the cost function and n is the number of control adjustments. Eq. (2) represents the set of network power flow algebraic equations, v denotes bus voltage with upper and lower limits $\overline{v}$ and $\underline{v}$ respectively, and u is the control variable with $\overline{u}$ and $\underline{u}$ being the upper and lower bounds. The cost "c" is used to enforce non-intrusive controls (switched shunts, LTCs, generator redispatch) as priority to alleviate violations before resorting to shedding loads.

The above OPF model is nonlinear due to the set of nonlinear power flow equations in (2). To increase the likelihood of a feasible solution and speed up computation time, the OPF formulation is linearized around an initial converged power flow solution, resulting in the following linear model:

Minimize: $$CX \tag{5}$$

Subject to: $$\text{A}X = B, \tag{6}$$

where C is the vector of cost factors, X is the vector of independent (control) and dependent variables, for example, bus voltage and line flows. A denotes the coefficient matrix determined from the initial converged solution and B is the input vector. The linear OPF model is solved using a successive linear programming method as illustrated in Fig. 3.

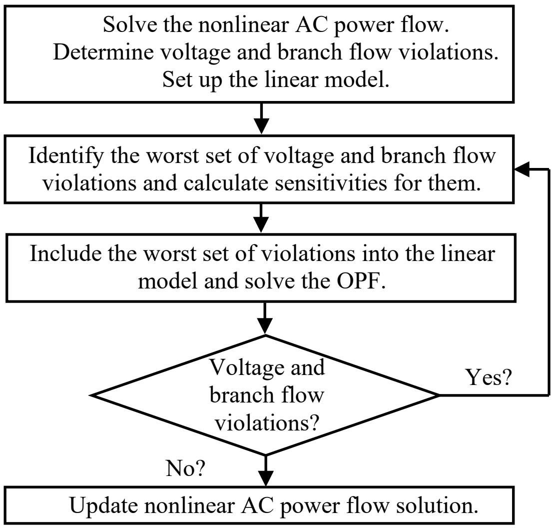

Figure 3. Successive Linear Program method

D. Expected Energy Not Served

The EENS in MWh is calculated based on the information of consequential LAR value in MW, MTTR (in hours) and number of outage occurrences the line experiences in a year (occ/yr), on average, as

$$EENS\left[\frac{MWh}{yr}\right] = LAR[MW] \times MTTR[h] \times \frac{occ}{yr}.$$

III. Proposed Framework

The proposed reliability framework is defined as follows:

1. Apply a B2B contingency, as explained in II.A, and designed as per [1].
2. Determine the consequential LAR and EENS as described in Sections II-B and II-D.
3. Run the Newton-Raphson power flow after applying the contingency to the power flow model and record all the security constraints violations, i.e., voltage and line thermal limit violations.
4. Formulate and solve the linear OPF model shown in Section II-C with the objective of minimizing security violations, as described in Fig. 3. Apply the control solution from OPF to solve the AC power flow model.
5. Finally, record the new set of load sheds (i.e., non-consequential LAR) and its corresponding EENS.

While solving the linear OPF, governor-based power flow plays a pivotal role. Traditionally, a single slack bus generator balances the system power imbalance after a contingency, ignoring real-life generation settings, incorrectly suggesting long-distance power travel and high technical losses. Using governor-based power flow, generators share the power imbalance based on their droop characteristics, ensuring realistic adjustments.

IV. Transmission Reliability Assessment of the Puerto Rico System

The proposed reliability framework is implemented on the transmission system of Puerto Rico. The island electric system suffered major destruction from Hurricanes Maria and Fiona in 2017 and 2022, respectively. FEMA allocated funds to recover and restore the system to its original state [9]. This system is going through major reconstruction and the generation, transmission and distribution operators are going to execute hundreds of major projects funded by FEMA under Sections 428 and 406. Section 406 comprises Hazard Mitigation measures, i.e., those that if they were in place during the disaster (e.g., hurricane Maria), the system would not have suffered damages. The intent of this section is to quantify potential reliability improvements pre- and post-Hazard Mitigation projects. As part of the resilience plan, FEMA is currently focusing on repairing or rebuilding substations, transmission and distribution systems with poor conditions. For this work, the authors have considered only the transmission system. All the simulations leverage automating runs of PSSE [10].

A. System Description and De-Rating Practices

The transmission system includes meshed networks at 230-kV, 115-kV and 38-kV levels as illustrated in Table I and Fig. 4. Most of the large load centers are located in the northern side, while most of the generation is in the south. Due to poor system conditions, the system operator operates lines and transformers de-rated. To capture the impact of these projects, we determined upon consultation with the system operator that the de-rating practice would be removed to categorize contingencies.

TABLE I. Puerto Rico Transmission Line Information

Transmission Lines	Line count (B2B)	Length [miles]
38-kV	185	1,563
115-kV	46	711
230-kV	12	424
Total	243	2,698

Figure 4. Puerto Rico transmission system.

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B. *Analyzing the Load-At-Risk*

The proposed reliability framework is implemented on the test case illustrated in Section IV-A and the consequential and non-consequential load at risk are determined. Fig. 5 shows the probability distribution function of aggregated consequential and non-consequential LAR due to contingencies on all PSSE branches (line and two-winding transformers). It is observed that most of the contingencies with Base Case have high LAR (100 MW average). On the contrary, the post-investment projects have small LAR. This signifies that the amount of LAR can notably be reduced by the proposed system reconstruction.

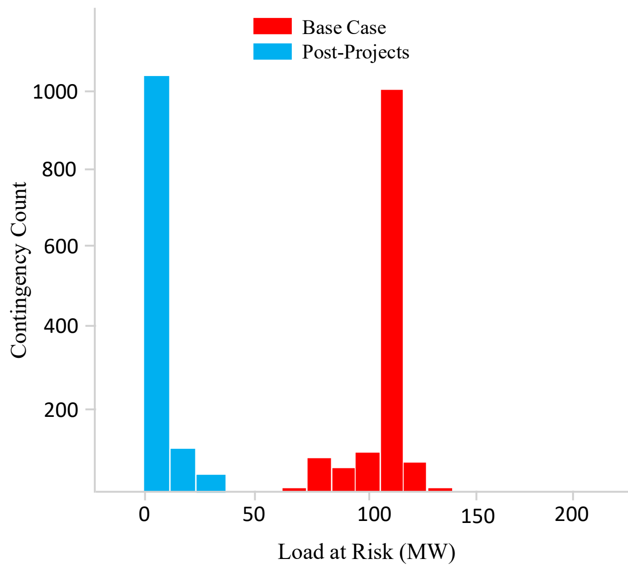

Figure 5. Histogram of aggregated consequential and non-consequential LAR for different contingencies.

The combined consequential and non-consequential LAR for sixteen B2B contingencies at 115-kV level is illustrated in Fig. 6. After project deployment, the LAR probability distribution greatly shifts left. Fig. 7 presents further visualization for all PSSE branches at all kV levels. While the average LAR with the base case is around 110 MW, it notably drops to around 5-10 MW post-projects.

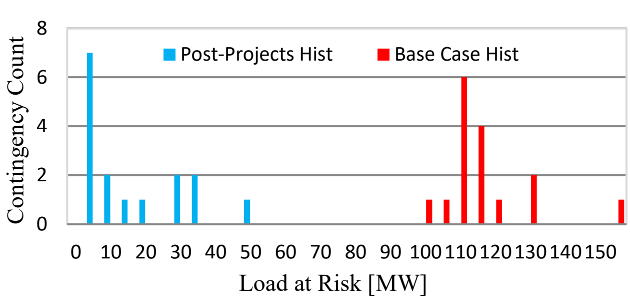

Figure 6. Histogram of load at risk for select B2B contingencies.

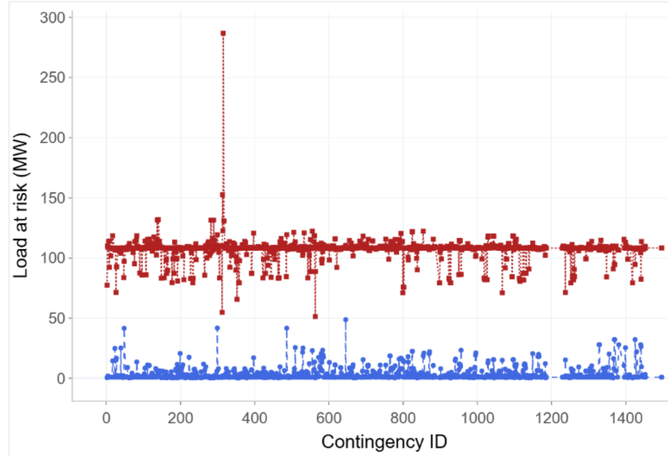

Figure 7. LAR for different contingencies (top and bottom results represent the base case without and with project deployment, respectively)

The area-wise impact of all B2B contingencies on aggregate LAR is presented in Fig. 8. It is noticed that areas 6 and 8 experience much greater benefit, as LAR sharply declines in post-projects. It is also beneficial to analyze the system-wide impacts of every possible contingency occurring in a particular area. To this end, the load shed over each area is represented in Fig. 9, which suggests that contingencies in different areas, regardless of where they occur, have similar impact on LAR. Improvement in terms of security violations is shown in Table II. The reduction and elimination of security violations are collected after performing the necessary corrective action during post contingency in both cases. Two security violations are eliminated, and the total number of violations are reduced by 293, leading to a reduction of 29.44 GW (89.1%) load shed over the entire network.

TABLE II. IMPROVEMENT IN SECURITY VIOLATIONS

Eliminated security violations	**Reduced security violations**	**Overall reduced load at risk**
2	293	29,444 MWs (89.1%)

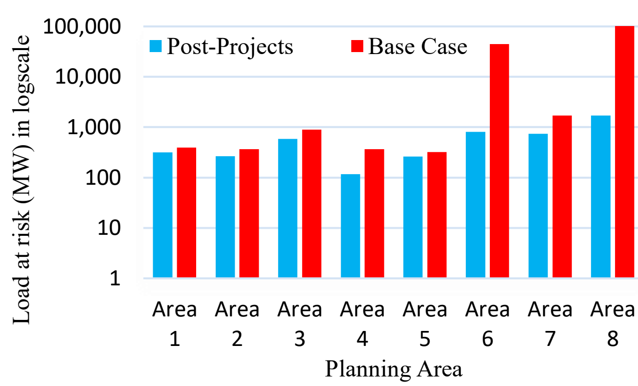

Figure 8. Total LAR in each planning area for B2B contingencies

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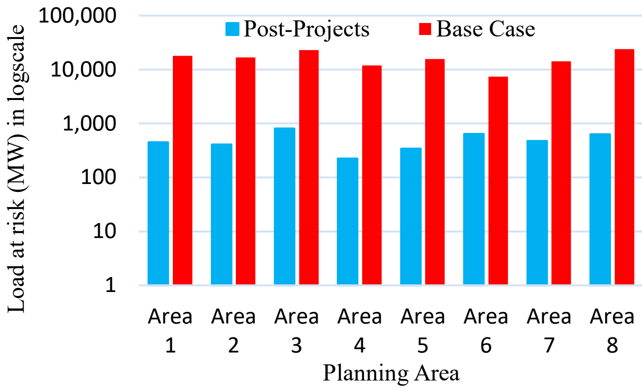

Figure 9. Total LAR grouped for all possible N-1 contingency within each planning area

C. Expected Energy Not Served

EENS is calculated for contingencies at various voltage levels. Fig. 10 illustrates the annual EENS for all 115kV and 230kV contingencies, suggesting a reduction of 98% post-projects For further illustration, the EENS for critical contingencies provided by the system operator (all are at 115kV) is plotted in Fig. 11, showing that the EENS after post-projects is reduced by 88% compared to the base case.

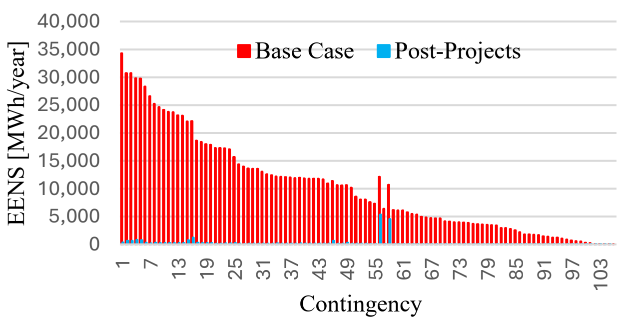

Figure 10. EENS for all possible 115kV and 230kV contingencies

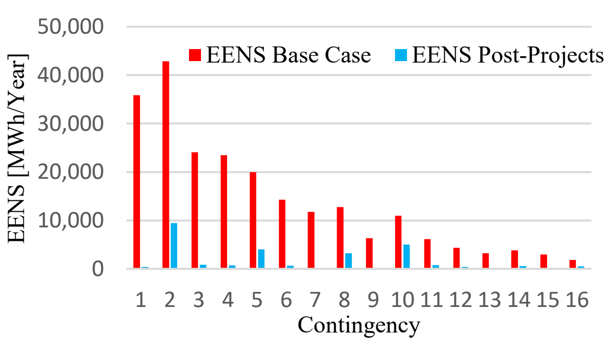

Figure 11. EENS for critical contingencies provided by the TSO

V. Conclusions

This paper presented a practical transmission reliability framework encompassing both consequential and non-consequential load at risk, which is founded on practical aspects of transmission system operation and involves breaker-to-breaker line contingency definition and realistic generation redispatch. In addition, the proposed method develops the expected energy not served as a metric to more tangibly determine system reliability. The framework is adopted in the Puerto Rico transmission system model, and demonstrates that the funds obligated by FEMA, both under Section 428 and 406, are critical to improve system reliability and reduce security violations by nearly 98%. Although the system will not become fully secure (as per NERC's TPL standard), the execution of these projects represents a great stride towards security.

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