A Resiliency Index (Ri) for Individual Transmission Lines and Aggregation to the North American Bulk Electric Transmission System

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Abstract

The reliability and resilience of the North American Bulk Electric Transmission System (BETS) has historically been assessed at the system level through probabilistic planning standards and post-event forensic analysis. These approaches, while valuable, do not provide a granular, real-time measure of how prepared individual transmission owner/operators (TO/Os) are to autonomously respond to catastrophic contingencies through automated outage mitigation devices. This paper proposes the Resiliency Index (Ri), a normalized scalar metric ranging from 0 to 100 that quantifies the degree to which a transmission line, substation, or SCADA switching point is equipped with automated devices capable of detecting, isolating, and restoring service without operator intervention. At the individual asset level, Ri captures the weighted ratio of automated to total protective functions, adjusted for voltage-class criticality and circuit miles. At the system level, individual asset Ri values aggregate into a BETS-wide resiliency profile that exposes structural vulnerabilities across reliability coordinator regions. The weighting methodology is derived from Rank Order Centroid (ROC) analysis, providing mathematically derived, auditable weights aligned with NERC Reliability Standards TPL-001 through TPL-007, FAC-001, PRC-023, and EOP-005/006. This paper motivates the need for Ri, defines its mathematical formulation, demonstrates its application to both individual lines and the aggregate BETS, and discusses its implications for regulatory oversight, investment prioritization, and the identification of cascading failure risk.

Index Terms**—***Bulk Electric Transmission System, cascading failure, power system resilience, Rank Order Centroid, resiliency index, NERC reliability standards, automated outage restoration, transmission line protection, SCADA automation, power system reliability.*

I. INTRODUCTION

The North American Bulk Electric Transmission System (BETS) is among the most complex engineered systems ever constructed, comprising more than 200,000 miles of high-voltage transmission lines, thousands of substations, and hundreds of individual transmission owner/operators (TO/Os) operating across multiple interconnections and reliability coordinator regions [1]. The reliable operation of this system is foundational to national economic activity, public health, and national security. Disruptions to bulk transmission—whether caused by severe weather, physical attack, cyber intrusion, or equipment failure—can trigger cascading outages affecting millions of consumers and causing economic losses measured in billions of dollars per day [2].

Despite decades of advances in power system protection and automation, no standardized, granular metric exists that quantifies how well-equipped any individual transmission line or substation is to autonomously respond to a catastrophic contingency. The current regulatory framework, anchored by NERC Reliability Standards including the TPL-001 through TPL-007 transmission planning series and the FAC-001/002 facility ratings standards, assesses system performance primarily through probabilistic load flow studies and post-event compliance reviews [3]. These approaches answer the question of whether a system will remain stable under defined contingency scenarios. They do not answer the equally important question: if a catastrophic event does occur, how much of the system's response capability is automated versus dependent on human intervention?

This distinction is critical. Modern catastrophic events—including the August 2003 Northeast Blackout, the 2011 Southwest Blackout, and Hurricanes Maria (2017) and Ida (2021)—have demonstrated that the speed of automated response in the first seconds to minutes following an initiating event is the primary determinant of whether a disturbance is contained locally or propagates into a wider cascading failure [4]. Human operators, regardless of training and experience, cannot match the sub-cycle response times of properly designed automated protection schemes. A transmission system populated with auto-reclosers, automatic transfer switches, SCADA-controlled sectionalizing switches, and adaptive protective relay schemes is fundamentally more resilient than one of identical physical capacity but with minimal automation, even if both satisfy all applicable NERC planning standards.

This paper proposes the Resiliency Index (Ri) as a standardized, transparent, and mathematically defensible metric to fill this measurement gap. Ri quantifies, on a 0-to-100 scale, the degree to which any individual transmission circuit or substation is equipped with automated outage mitigation devices. The index aggregates from the individual asset level to the operator level, and from the operator level to the BETS-wide level, creating a hierarchical resiliency profile that regulatory bodies, reliability coordinators, and policymakers can use to identify structural vulnerabilities and prioritize investment in grid automation.

II. BACKGROUND AND MOTIVATION

A. The Resilience–Reliability Distinction

Power system engineering has long distinguished between reliability—the probability that a system will perform its intended function under stated conditions—and resilience—the ability of a system to adapt to, absorb, and recover from extreme disruptions [5]. NERC's Reliability Standards, while comprehensive in their treatment of reliability, do not include a quantitative metric for resilience as defined above. The IEEE Power and Energy Society has recognized this gap, noting in multiple technical reports that bulk transmission resilience metrics remain an area of active research without an established industry standard [6].

Resilience in the context of transmission systems has several distinct phases: (1) anticipation, the ability to predict and prepare for threats; (2) absorption, the ability to maintain function during a disturbance; (3) adaptation, the ability to dynamically reconfigure to minimize impact; and (4) restoration, the ability to return to normal operation quickly [7]. The Ri proposed in this paper focuses primarily on the adaptation phase—specifically, the ability of automated devices to dynamically reconfigure a transmission system during a catastrophic event without human intervention. This is the phase where the gap between automated and non-automated systems is most consequential.

B. Catastrophic Events and the Automation Imperative

The causal chain in major transmission outages is well-documented. An initiating event—a line fault, equipment failure, or external attack—triggers protection device operation. If the affected element is not isolated quickly and cleanly, the resulting power flow redistribution can overload adjacent elements. If those adjacent elements are also not equipped to automatically respond, successive trips can follow in a cascading pattern. The 2003 Northeast Blackout, which affected 55 million people and caused an estimated $6 billion in economic losses, was initiated by a software failure in an energy management system that blinded operators to an evolving voltage collapse—but the cascade was enabled by the absence of sufficient automated isolation on the Ohio transmission system [8].

More recently, the February 2021 Texas winter storm demonstrated that even a modern, well-instrumented transmission system can fail catastrophically when automated protection systems interact unexpectedly with fuel supply failures. The event underscored that resilience is not a binary property—it is a continuous spectrum, and systems with higher degrees of automation at the circuit level retain more degrees of freedom to respond to novel, multi-vector catastrophic scenarios [9].

C. The Absence of a Granular Automation Metric

Current industry practice does not include a standardized metric for the automation density of individual transmission circuits. NERC's data collections—including the Transmission Availability Data System (TADS) and the Generating Availability Data System (GADS)—capture outage frequency and duration data but do not capture the automation profile of the assets involved [10]. FERC's transmission planning orders (Orders 890, 1000) require documentation of planning processes but do not mandate automation-level reporting. State regulatory commissions generally lack the technical framework to evaluate automation adequacy at the circuit level.

This absence creates a measurability gap with three important consequences. First, it prevents regulators and reliability coordinators from identifying which portions of the BETS are most vulnerable to cascading failure due to inadequate automation. Second, it prevents TO/Os from benchmarking their automation investments against peers and against a defined standard. Third, it prevents cost-benefit analyses of automation investment from being conducted at the system level, where the aggregate resilience effect of distributed automation investments is most pronounced. The Ri is proposed as the instrument to close all three gaps.

III. MATHEMATICAL FORMULATION OF THE RESILIENCY INDEX

A. Definitions and Scope

The following terms are defined for purposes of this paper:

- Automated Outage Mitigation Device (AOmD): Any device capable of detecting an abnormal operating condition and executing a protective or restorative switching action without operator intervention, including auto-reclosers, ATS, SCADA-controlled switches, UFLS/UVLS relays, and adaptive protective relay schemes.
- Asset: Any individual transmission circuit or substation at or above 69 kV subject to NERC BES definition.
- Automation Score (a): A continuous scalar between 0.0 and 1.0 representing the fraction of total protective functions performed by AOmDs. a = 1.0 denotes full automation; a = 0.0 denotes no automation.
- Voltage Criticality Factor (V_k): A multiplicative factor applied to circuit miles or MVA capacity to weight higher-voltage assets more heavily in proportion to cascading failure potential.

B. Asset-Level Automation Score

For each individual transmission circuit i, the automation score a_i is computed as:

$$a_i = F_{auto,i} \; / \; F_{tota\ell,i} \qquad (1)$$

where $F_{auto,i}$ is the number of protective functions performed by AOmDs and $F_{tota\ell,i}$ is the total number of protective functions on circuit i. This formulation allows partial automation to be represented continuously. For example, a 115 kV circuit with a SCADA-monitored recloser but manual sectionalizing switches might have $F_{auto} = 3$ and $F_{tota\ell} = 5$, yielding $a_i = 0.60$.

C. Voltage-Class Criticality Adjustment

Not all transmission circuits contribute equally to system resilience. A fault on a 500 kV interstate tie line exposes far more load to cascading risk than a fault on a 69 kV sub-transmission circuit. A Voltage Criticality Factor V_k is therefore applied to each voltage class k (Table I).

kV	V_k	Rationale
500	5.0	EHV interstate ties; NERC Category P7 event risk
345	3.5	Regional backbone; cascade propagation risk per TPL-003
230	2.3	Transmission backbone; common initiating cascade path
138	1.4	Sub-regional transmission; moderate cascade exposure
115	1.2	Lower BES threshold per NERC definition
69	1.0	Sub-transmission baseline included per study scope

TABLE I Voltage Criticality Adjustment Factors by Nominal Voltage Class

The voltage-adjusted weight for circuit i is:

$$w_i \; = \; L_i \; \times \; V_{k(i)} \tag{2}$$

where L_i is circuit length in miles. For substations:

$$w_j \; = \; S_j \; \times \; V_{k(j)} \tag{3}$$

where S_j is the rated MVA capacity of substation j.

D. Criterion-Level Weighted Automation Ratio

For each asset category c, the weighted automation ratio A^c is the capacity-weighted average of individual automation scores:

$$A^c \; = \; \Sigma_i \, (\, a_{i,}{}^c \times w_{i,}{}^c \,) \;\; / \;\; \Sigma_i \, w_{i,}{}^c \tag{4}$$

This ensures that high-voltage, long-span circuits contribute proportionally more to A^c than short, lightly loaded sub-transmission segments. A^c ranges from 0.0 to 1.0.

E. ROC Weighting of Asset Categories

The five asset categories are not equal in their contribution to system resilience. Rather than assigning weights arbitrarily, this paper employs Rank Order Centroid (ROC) weighting [11]. For k ranked criteria, the weight for criterion of rank r is:

$$w_r \; = \; (1/k) \times \Sigma_{j=r}{}^k \, (1/j) \tag{5}$$

For k = 5 criteria ranked in order of criticality (circuits, substations, SCADA switching points, ATS/transfer schemes, relay schemes), equation (5) yields the weights shown in Table II.

Rank	Category	ROC Formula	w_r	NERC Std
1	Transmission Circuits	(1/5)(1+½+⅓+¼+⅕)	0.4567	TPL-001–7, FAC-001
2	Substations	(1/5)(½+⅓+¼+⅕)	0.2567	FAC-001, EOP-005
3	SCADA Switching Points	(1/5)(⅓+¼+⅕)	0.1567	PRC-023, EOP-006
4	ATS / Transfer Schemes	(1/5)(¼+⅕)	0.0900	EOP-005, TPL-003
5	Relay Schemes (UVLS/UFLS)	(1/5)(⅕)	0.0400	PRC-023, EOP-006
	TOTAL		**1.0000**	

TABLE II ROC-Derived Criterion Weights for the Resiliency Index

F. The Ri Master Formula

The Resiliency Index for a transmission owner/operator is:

$$Ri \;\; = \;\; 100 \; \times \; \Sigma^{c}{}_{=1}{}^{5} \, (\, w^c \times A^c \,) \tag{6}$$

Substituting the ROC weights from Table II:

$$Ri = 100 \times [0.4567A_1 + 0.2567A_2 + 0.1567A_3 + 0.0900A_4 + 0.0400A_5] \tag{7}$$

where A_1 through A_5 are the weighted automation ratios for circuits, substations, SCADA switching points, ATS/transfer schemes, and relay schemes, respectively. An Ri of 0 indicates a complete absence of automated devices; an Ri of 100 indicates that all assets in all five categories are fully automated.

IV. APPLICATION TO INDIVIDUAL TRANSMISSION LINES

A. Single-Circuit Ri

At the finest resolution, the Ri formula reduces to a single-circuit automation assessment:

$$Ri_i \;\; = \;\; 100 \times a_i \;\; = \;\; 100 \times (F_{auto,i} \, / \, F_{total\ell,i}) \tag{8}$$

This single-circuit Ri does not incorporate the ROC category weights. Its value represents the fraction of that circuit's total protective functions that are automated, scaled to 0–100.

B. Line-Level Ri Interpretation

The single-circuit Ri carries specific operational implications:

- Ri = 0: No automated protection or restoration. All response requires manual switching; response times range from minutes to hours.
- Ri = 1–33 (Low): Some automated protection (e.g., distance relay) but no automated restoration.
- Ri = 34–66 (Moderate): Automated fault isolation and partial restoration; sectionalizing may require operator coordination.

- Ri = 67–99 (High): Comprehensive automated protection, isolation, and restoration.
- Ri = 100: Full automation of all protective and restorative functions—a fully self-healing circuit.

C. Worked Example—Single Circuit

Consider a 230 kV transmission circuit spanning 95 miles with the following protection inventory: (1) digital distance relay—automated; (2) breaker failure relay—automated; (3) single-shot auto-reclose—automated; (4) direct transfer trip (DTT)—automated; (5) manual sectionalizing switch at midpoint—not automated; (6) manual load restoration at receiving substation—not automated; (7) fault location indicator—automated.

This yields $F_{auto} = 5$ and $F_{tota}\ell = 7$, giving $a_i = 0.714$. The voltage-adjusted weight is $w_i = 95 \times 2.3 = 218.5$. The single-circuit Ri = 100 × 0.714 = 71.4 (High). To reach Ri = 100, the TO/O would need to automate the midpoint sectionalizing switch via SCADA and implement an automated load restoration scheme at the receiving substation.

V. AGGREGATION FROM INDIVIDUAL LINES TO THE BETS

A. Operator-Level Aggregation

The operator-level Ri is computed by applying equation (6) across the entire asset inventory of a TO/O. For a TO/O with N^c assets in category c:

$$A^{c},TO/O = \Sigma_{i} (a_{i},^{c} \times w_{i},^{c}) / \Sigma_{i} w_{i},^{c} \tag{9}$$

The operator Ri is then:

$$Ri_{to}/_{o} = 100 \times \Sigma^{c}{}_{=1}{}^{5} (w^{c} \times A^{c},TO/O) \tag{10}$$

B. BETS-Wide Aggregation

The BETS-wide Ri is computed as a capacity-weighted average of operator-level Ri scores across all M operators:

$$Ri^{bMT}_{s} = \Sigma_{m} (Ri_{m} \times W_{m}) / \Sigma_{m} W_{m} \tag{11}$$

where W_m is the total voltage-adjusted asset size of operator m:

$$W_{m} = \Sigma_{i} \in_{m} (L_{i} \times V_{k}(_{i})) + \Sigma_{j} \in_{m} (S_{j} \times V_{k}(_{j})) \tag{12}$$

This weighting ensures that large, high-voltage operators—whose assets carry the greatest cascading failure risk—contribute proportionally more to Ri^{bMT}_{s} than small, low-voltage operators.

C. Statistical Characterization of BETS Resiliency

A complete BETS resiliency profile requires distributional characterization. Standard reporting elements include:

- Mean Ri (μ): Capacity-weighted average across all BETS operators, representing the central tendency of BETS automation density.
- Standard Deviation (σ): Spread of Ri scores. High σ signals structurally uneven automation investment.
- Z-Score per Operator: $Z_m = (Ri_m - \mu) / \sigma$, enabling cross-operator benchmarking independent of scale.
- Percentile Rank: Each operator's position in the distribution of BETS Ri scores.
- 95% Confidence Interval on Ri^{bMT}_{s}: Bounds on the BETS mean from the t-distribution.
- Regional Ri Profiles: Ri^{bMT}_{s} disaggregated by NERC Reliability Coordinator region.

D. Cascading Failure Risk Exposure via Ri Gap Analysis

A critical application of BETS-wide Ri aggregation is the identification of automation gap clusters—contiguous geographic regions where multiple adjacent operators have low Ri scores. Because cascading failures propagate across operator boundaries, a cluster of low-Ri operators creates a systemic vulnerability not visible when examining individual operator compliance in isolation.

Gap analysis is conducted by mapping operator Ri scores onto the BETS topology and identifying contiguous regions where Ri < 25 (Critical Gap classification). These regions represent the highest-priority targets for regulatory attention—an initiating event in such a region is most likely to propagate without automated containment.

VI. REGULATORY AND POLICY APPLICATIONS

A. NERC Reliability Standard Integration

The Ri is designed to complement, not replace, existing NERC Reliability Standards. Its natural position within the standards hierarchy is as a supplementary metric reported under TPL-001 alongside existing probabilistic load flow results. TO/Os would report their operator-level Ri annually, disaggregated by the five asset categories, along with a year-over-year trend and a corrective action plan for any category with $A^c < 0.25$.

At the BETS level, NERC would publish an annual Ri^{bMT}_{s} and regional Ri profiles as part of its Long-Term Reliability Assessment, providing policymakers, RTOs, and state commissions a standardized metric for assessing progress in grid automation—analogous to SAIDI and SAIFI in distribution reliability reporting.

B. Investment Prioritization

The Ri provides a mathematically defensible basis for prioritizing automation investment. Because circuits carry the highest ROC weight (0.4567), automation investments in circuits—particularly on high-voltage, long-span lines with $V_k \geq 2.3$—yield the highest marginal Ri improvement per dollar invested. FERC transmission incentive rate proceedings could incorporate Ri improvement commitments as a condition of enhanced ROE treatment, creating a direct financial incentive for automation investment.

C. Interconnection Resilience Benchmarking

The Ri framework naturally extends to interconnection-level benchmarking across the Eastern Interconnection, Western Interconnection, and ERCOT. Because the formula and weighting are standardized, Ri scores computed in different interconnections are directly comparable, enabling cross-interconnection analysis and continent-wide resilience targets.

D. Emergency Operations and Mutual Aid Optimization

During major events requiring mutual aid under EOP-005, the Ri profiles of participating operators can inform dispatch of automation-capable resources to low-Ri areas where manual restoration would otherwise be the only option. The Ri thus has operational as well as analytical value.

VII. LIMITATIONS AND FUTURE RESEARCH

A. Data Collection Challenges

The primary implementation challenge for Ri is data collection. The automation inventory required to compute F_{auto} and $F_{tota}\ell$ for every circuit and substation in the BETS does not currently exist in any centralized database. A phased implementation would be required, beginning with self-reported data from TO/Os and progressively moving toward third-party verification integrated with asset management systems.

B. Device Effectiveness vs. Device Presence

The current Ri formulation counts the presence of automated devices but does not assess their operational effectiveness. A circuit with a SCADA-controlled switch that is communication-impaired is nominally automated but functionally unavailable. Future research should explore incorporation of device availability and MTBF metrics into the automation score, yielding an availability-adjusted Ri ($Ri_{a}{}^{\beta}{}_{ai}\ell$).

C. Interdependency with Communications Infrastructure

SCADA-controlled switches and communications-assisted relay schemes depend on communications infrastructure with its own resilience characteristics. A transmission circuit on a communications infrastructure vulnerable to the same event (e.g., a hurricane disabling both the switch control link and the line) may have an overstated Ri. Future research should develop a communications resilience sub-index to adjust automated device scores for control-communications independence.

D. ROC Weight Validation

The ROC weights are derived from a rank ordering reflecting the author's assessment based on historical outage data and engineering judgment. This ranking is a modeling assumption requiring validation through engagement with NERC reliability coordinators, TO/O protection engineers, and academic researchers. Sensitivity analysis and development of a stakeholder consensus process for rank-order determination are important areas for future research.

VIII. CONCLUSION

This paper has proposed the Resiliency Index (Ri) as a standardized, mathematically transparent metric for quantifying the automated outage mitigation capability of individual transmission lines, transmission owner/operators, and the BETS as a whole. The key contributions are:

- A formal mathematical framework for computing Ri at the circuit, operator, and BETS levels, incorporating continuous automation scoring, voltage-class criticality adjustment, and ROC-derived category weighting.
- Alignment of the Ri weighting structure with NERC Reliability Standards (TPL-001–7, FAC-001, PRC-023, EOP-005/006), enabling integration into existing regulatory reporting frameworks.
- Demonstration that individual circuit Ri values aggregate hierarchically to expose structural vulnerabilities in the BETS invisible to existing compliance-focused assessment methods.
- Identification of regulatory, investment, and operational applications of the Ri, including NERC reporting integration, capital prioritization, cross-interconnection benchmarking, and mutual aid optimization.

The increasing frequency and severity of catastrophic events affecting the North American transmission grid makes the development of granular, actionable resilience metrics an urgent priority. The Ri provides a framework simple enough to communicate to policymakers, rigorous enough to withstand engineering scrutiny, and flexible enough to accommodate future evolution in automated grid technologies including advanced distribution management systems, grid-forming inverters, and AI-driven adaptive protection schemes.

The author invites engagement from NERC, FERC, regional transmission organizations, transmission owner/operators, and the IEEE Power and Energy Society in the further development, validation, and standardization of the Ri as an industry-wide resiliency metric.

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APPENDIX: SUMMARY OF NOTATION

Symbol	Definition
Ri	Resiliency Index for an asset, operator, or BETS (0–100)
Ri^{bMT_s}	BETS-wide capacity-weighted average Resiliency Index
Ri_m	Resiliency Index for operator m
Ri_i	Resiliency Index for individual circuit i
a_i	Automation score for asset i: $F_{\mathrm{auto},i} / F_{\mathrm{tota}\ell,i} \in [0,1]$
$F_{auto,i}$	Automated protective/restorative function count on asset i
$F_{tota\ell,i}$	Total protective/restorative function count on asset i
V_k	Voltage Criticality Factor for voltage class k
L_i	Length of circuit i in miles
S_j	Rated MVA capacity of substation j
w_i	Voltage-adjusted weight for circuit i: $L_i \times V_{k(i)}$
w_j	Voltage-adjusted weight for substation j: $S_j \times V_{k(j)}$
A^c	Weighted automation ratio for asset category c $\in [0,1]$
w^c	ROC-derived criterion weight for category c (sum = 1.0)
k	Number of ranked criteria in ROC weighting (k = 5)
r	Rank of a criterion (1 = highest importance)
M	Total number of BETS operators
W_m	Total voltage-adjusted asset size of operator m
μ	BETS mean Ri across all operators
σ	Standard deviation of operator Ri across the BETS
Z_m	Z-score for operator m: $(Ri_m - \mu) / \sigma$

TABLE A-I Summary of Mathematical Notation

Casey Shull, PhD is an expert in bulk electric transmission reliability, resilience metrics, power system automation, project management and systems engineering. Dr. Shull’s research focuses on the development of quantitative frameworks for assessing and improving the automated response capability of the North American Bulk Electric Transmission System, merging of project management and systems engineering, cost and schedule anomaly detection. Correspondence regarding this manuscript should be directed to the author through the IEEE Transactions on Power Systems submission portal.