An Econometric Approach for Impact of Uncertainties in TCO of Transmission Lines

Miroslav M. Begovic, LFIEEE
Dept. of Electrical and Computer Engineering
Texas A&M University, College Station TX, USA
begovic@tamu.edu

Paul Springer, PE, Principal
Springer Power Consulting, LLC
Alpharetta, GA USA
consult.pls1@gmail.com

Abstract—**The objective of the paper is assessment of the costs associated with design, planning and operation of transmission lines. The motivation and need for transmission asset expansion are driven by a rapid increase of energy needs due to new types of loads (electric transportation, data centers, etc.), as well as the need for better grid resilience under extreme weather conditions. An econometric approach is proposed, based on the stochastic model for evaluation of the Total Cost of Ownership (TCO) of electric transmission lines from perspectives of the capital expenditure, and costs of maintenance and operation over a 50-year estimated lifetime of the new transmission lines, planning for a strong and well-connected system, and more accurate assessment of the total costs associated with design and operation. The approach described in the paper offers new perspectives on design, construction and operation of transmission lines. The authors exploit the methodologies to incorporate the uncertainties in TCO for new line designs (our reference [24]), in consideration of extreme weather and rapidly increasing loads, and providing an assessment of potential impact and benefits of the proposed approach.**

Index Terms-- **New and reconductored transmission line design, transmission line cost of operation, stochastic simulation, econometric models, total cost of ownership (TCO).**

I. Introduction

A growing body of industry research and international practice recognizes total cost of ownership (TCO) as a comprehensive metric for evaluating transmission investments across their service life. In addition to initial capital expenditures, TCO frameworks incorporate maintenance strategies, asset aging and refurbishment cycles, system losses, reliability impacts, end-of-life considerations, and uncertainty in technical and economic conditions. These approaches support prudent planning by capturing long-term system value and risks, aligning investment decisions with asset-management principles, cost-recovery policies, and long-term ratepayer benefit. Recent utility applications of TCO include conductor selection, uprating and reconductoring strategies, comparative assessment of conventional and advanced conductors, and evaluation of maintenance and resilience options, reinforcing the role of TCO as a transparent and defensible methodology for decision-making.

The development and testing of the stochastic total cost of ownership (TCO) model for transmission lines is grounded in well-established engineering, asset-management, and regulatory-grade analytical frameworks. Probabilistic reliability and service-risk principles follow the foundational methods of [1]. Life-cycle cost structure, treatment of uncertainty, and documentation transparency are aligned with internationally recognized asset-management standards, including IEC 60300-3-3 [2], focused on acceptable investment decisions. Transmission-specific life-cycle guidance from CIGRÉ TB 331 [3] and conductor performance and uprating considerations from CIGRÉ TB 353 [4] ensure the model reflects current engineering practice and technology assessment used in transmission asset planning.

System performance impacts—including losses and system stability effects—are grounded in established power-system engineering principles [5]. Stochastic methods applied in the model follow proven approaches for decision-making under uncertainty [6],[7], supporting prudent evaluation of cost ranges rather than reliance on single-point estimates. Finally, the treatment of transmission losses draws on established loss-allocation methods [8], providing accurate recovery of long-term operating costs.

To support a rigorous and utility-grade TCO framework, this model incorporates current industry practice, empirical cost data, and internationally recognized transmission planning standards. Technical guidance on reconductoring and uprating, including cost, performance and installation considerations for advanced conductors, follows CIGRÉ recommendations [9], [11], with thermal rating and conductor aging treatment from established overhead line rating practice [10]. Asset life-extension and refurbishment cycles are informed by CIGRÉ sustainability and condition-assessment guidance [17].

Cost parameterization draws on authoritative U.S. sources, including DOE national transmission cost data [13] and EIA capital benchmarks [14], with comparative economics of reconductoring and new construction supported by recent

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North American studies [15], [16]. O&M structure and long-term maintenance expectations are anchored in FERC's transmission accounting standards [18]. Regional cost-estimation frameworks and planning criteria reflect MISO methodology [19] and ISO-NE transmission planning processes [20], while empirical experience from the CapX2020 build program provides real-world cost and schedule context [21]. International cost benchmarking is drawn from the IET transmission costing study [22], and benefit allocation and transparency principles follow the policy framework established under FERC Order No. 1000 [23]. Collectively, these sources ensure the TCO model relies on engineering-validated assumptions, verified cost ranges, and planning practices consistent with modern regulatory expectations.

II. Total Cost of Operation (TCO) Model

On the basis of separation of the total cost of ownership (TCO) into three main components [24], including transmission line design (or re-conductoring design), right-of-way acquisition and preparation, and associated construction and other related costs which constitute capital expenditures $CAPEX_0$, followed by O&M costs $O\&M_t$ in year t and incurred loss costs $LossCost_t$ over the time period spanning what is now expected to be over 50 years, and residual value RV_t (1) representing a conglomerate of costs

$$\mathrm{TCO}(a) = \mathrm{CAPEX}_0(a) + \sum_{t=1}^{T} \frac{\mathrm{O\&M}_t(a) + \mathrm{LossCost}_t(a)}{(1+r)^t} - \frac{\mathrm{RV}_T(a)}{(1+r)^T} \tag{1}$$

The nomenclature of (1) is self-explanatory, whereby r represents the discount rate, which provides a way of equalizing the recurring costs over a long period of time to a common point in time. This decomposition aligns with international cost–benefit guidance used in regulated transmission planning and U.S. utility practice (ISO/RTO planning documents) [25], [30], [32].

A. *Capital expenditures and key uncertainties*

Capital expenditure CAPEX is built from structure, foundation, conductor/OTS, hardware, construction labor/equipment, right-of-way/permitting/environmental, and contingency. For new lines, unit-cost parameterization and escalation can follow the guide [30]. The source [27] provides international cross-checks by voltage class and technology (OHL vs. cable). For reconductoring, engineering feasibility and cost deltas should reflect CIGRÉ guidance [26].

The main CAPEX stochastic drivers are: (i) commodity-linked materials (conductors, steel, concrete), (ii) labor productivity and construction logistics, (iii) permitting/ROW and schedule slippage, and (iv) contingency policy. For distributions, practical sources include regulator-facing policies for contingency and escalation [27], [30], [32]. Source [29] materials provide U.S. methodology context (e.g., the WECC/Black & Veatch transmission cost calculator used in federal studies) and can anchor benchmarking.

B. *O&M over multi-decade time horizons*

For O&M, we structure annual costs into routine inspection, vegetation management, corrective & minor capital repairs, condition-based maintenance (CBM), and storm/outage restoration. Utility reporting under *FERC Form 1* supplies a standardized taxonomy, facilitating calibration and peer comparison [31]. For older assets or reconductored spans, condition assessment & life-extension interventions are addressed in [26].

C. *Losses: thermal rating, temperatures, price exposure*

Annual losses can be computed from hourly $I^2R(t)$, with conductor resistance $R(t)$ as a function of time, i.e. operating temperature and age. The *CIGRÉ Thermal-Rating Guide* [28] summarizes deterministic and dynamic rating methods. Monetization multiplies hourly losses by energy prices and aligns with planning practice [25], [32], [33].

D. *Discount rate selection and impact*

Discounting materially affects the balance between up-front CAPEX and deferred O&M/loss costs. Among widely used reference points is *U.S. OMB Circular A-94 Appendix C* real discount rates for federal cost-effectiveness analysis (updated annually), providing government baselines derived from Treasury yields; current tables for calendar-year analyses are published each December [35], [36], [25]. Planning documents often encourage sensitivity around a base real r to test robustness and reflect capital-market variability [25], [32], [35], [36]. What are we gaining by developing and using a stochastic TCO model?

Experience shows that point estimates mask correlated risk among cost categories and operating conditions. A stochastic model (Monte Carlo or quasi-Monte Carlo with correlated draws) characterizes (i) CAPEX spread from unit-cost/productivity and schedule/contingency risk, (ii) O&M spread from vegetation cycles, storm events, and condition-based interventions, and (iii) loss spread from weather/flow/price interactions. Practical parameterization can proceed as follows: *CAPEX distributions and correlations:* Start with MISO MTEP component tables for central values; impose log-normal or triangular spreads around materials and labor; treat contingency as a bounded random factor (documented policy in MISO/IET) [27], [30]. *O&M distributions:* model storm/repair as Poisson–severity or compound processes; use CIGRÉ life-extension guidance [26], [31]. Draw hourly weather from weather-resampled years; link resistance and rating to CIGRÉ methods; multiply by price scenarios anchored to EIA/AEO long-run trajectories with high/low bands [28], [33]. For discount rates, run low/central/high real rates using A-94 Appendix C tables for the analysis year, plus an ENTSO-E-style sensitivity set; report TCO r [25], [35], [36].

The discount rate exerts a strong cross-component effect on rankings: MISO guide for cost structure/escalation [30], CIGRÉ for engineering constraints and rating/loss physics [26], [28], FERC Form 1 for O&M taxonomy and magnitudes [31], ENTSO-E CBA for discounting and robustness practice [25], and OMB A-94 for annually updated real-rate tables

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[35], [36]. The federal context and method references for U.S. cost calculators and multi-region planning are found in [29].

In sum, adopting a stochastic TCO framework is not only methodologically sound but also regulator-defensible: it quantifies realistic cost and performance ranges over a 50-year horizon, illuminates the tradeoffs between up-front capital and long-run operating streams under plausible discounting, and directs data collection to authoritative public sources for parameter means, spreads, and dependencies.

III. Future-Proofing the Transmission Line

Southern Texas transmission corridors that connect the Gulf Coast, San Antonio–Austin, and interior load centers face dual challenges: extreme-weather and unprecedented load growth. Future-proofed 500 kV designs must address environmental resilience, grid reliability, and scalability for high-demand nodes—especially data centers and electrified industrial facilities—under increasingly volatile climate and operational conditions.

A. *Extreme-Weather Design Considerations*

Southern Texas experiences both tropical-cyclone-level winds and episodic freezing rain and ice. A future-proofed 500 kV transmission line must integrate extreme-wind and combined ice/wind load cases into design per ASCE Manual 74 and the 2023 NESC [36], [37], including mechanical damping, galloping suppression, and low-temperature steel performance [38], [39]. Design targets include 115–140 mph 3-second gusts in coastal regions, combined ice/wind, low-temperature criteria inland, and tower design for 50–100 year return periods. Steel monopoles or lattice towers following ASCE 74 Rule 250C/D, coupled with ruggedized conductors, provide high mechanical reliability and operational flexibility.

B. *Load Growth and Transmission Scalability*

ERCOT’s 2024–2025 regional transmission planning reports forecast peak demand above 150 GW by 2030, with 40–50 GW from large-load interconnections (primarily data centers and industrial users). Ref. [44] estimates total interconnection requests near 200 GW, dominated by data center clusters around DFW, Austin–San Antonio, and the Gulf Coast. Nationally, large industrial electrification and AI-related loads are driving over 120 GW of new demand within five years.

To meet this surge, future-proofed 500 kV corridors must support N-1-1 operation, redundant feeds, and high continuous current capacity (>3,000 A per circuit). 500 kV backbones can interconnect renewable hubs, load centers, and future grid-scale storage while reducing system losses and congestion. ERCOT’s 2024 RTP comparison demonstrates that upgrading the network to 500–765 kV can reduce total losses by ~5% and curtailment by several *TWh* annually [43].

C. *Lifecycle and TCO Implications*

Resilient 500 kV designs typically increase CAPEX by 10–25% compared with baseline NESC-compliant construction, driven by heavier tower sections, larger foundations, and high-performance conductors. For Texas, this equates to roughly \$2.3–3.6 million per mile (345 kV) and \$3.5–5.0 million per mile (500 kV). O&M costs increase modestly (0.1–0.3% of CAPEX/yr) due to inspection and monitoring, but long-term reliability improvements yield 20–50% fewer major weather-related outages. Over a 50-year horizon, expected-value TCO rises only ~5–10%, which is typically offset by avoided outage energy-not-served and deferred rebuild costs.

D. *Example: Coastal-to-Inland Expansion Corridor*

A 500 kV corridor linking a Gulf Coast substation to central Texas load zones would employ hurricane-resistant monopoles and deep foundations for coastal spans, transitioning inland to anti-galloping hardware and ice-rated designs. Quad-bundle advanced conductors provide sufficient ampacity to support large data center clusters. CAPEX premium is estimated at +15–20%, O&M +0.2% of CAPEX/yr, and outage reduction of ~35%. These characteristics align with NERC’s evolving probabilistic risk approach and ERCOT’s large-load interconnection reliability criteria.

TABLE I. Estimated TCO Sensitivities to Resilient Designs

Component Costs	Baseline Value	Resilient Adjustment	TCO Impact / Rationale
CAPEX	\$2.6–5.0M/mi	+10–25%	↑5–8% TCO —
heavier towers, HTLS conductors, deeper foundations			
O&M	1.0% CAPEX/yr	+0.1–0.3%	↑0.5% TCO —
additional monitoring, vegetation & inspection			
Reliability/Energy Not Served	\$12M (50yr baseline)	−30–40%	↓4–6% TCO — outage red.
Losses	Baseline	−3–5%	↓1–2% TCO —
higher capacity conductors, reduced sag			

Table I summarizes the approximate changes in terms of percent of baseline design TCO to capital, operational, and reliability cost components for future-proofed 345–500 kV transmission line designs in southern Texas. Values reflect typical conditions for hurricane and icing resilience upgrades under ERCOT/NERC planning assumptions over a 50-year horizon [36].

IV. Examples of Stochastic TCO Calculation

Transmission line design examples presented herein are based on alternative redesign of a renewables mega project constructed in the western United States. It is triple-bundle 500 kV on tubular structures. The conductor is 1780 kcmil ACSR “Chukar” (*Design 1*), with a maximum rating of 1619 A. Simplifying assumptions include only a single structure design with consistent 800 ft spans. A traditional TCO method was used to compute the estimated total owning costs.

This same design was considered for two alternative advanced conductors: 1590 kcmil "Falcon ACSS/MA5" (steel core, *Design 2*), and 1582 kcmil ACCC "Bittern" (polymer core, *Design 3*). Both offer capacity increases over the larger “Chukar” ACSR. Both also have less sag at any given capacity rating. The monetary value of the sag reduction is accounted for by considering the sag of “Chukar” at rated capacity. A longer span length is possible for conductors with lower sag. The “Chukar” ACSR design requires 792 structures. The ACCC conductor and the ACSS/MA5 conductor require 646 and 712 structures (towers).

Concerns over extreme weather led to the idea of designing the same transmission line using hardened

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conductors and designing for NESC "Heavy" loads with an additional requirement to meet sag and tension limits with one inch of radial ice. 1590 kcmil "Falcon/ZTACSR/TW/MA5" and 1582 kcmil ACCC/ULS "Bittern" are hardened versions of the conductors used in the mild climate zones. The uncertainties of the TCO variables used for calculations were obtained from the experience in planning and design of one of the authors and information from the rich list of literature, discussed above, including a number of standards and guides.

TABLE II. Summary TCO Statistics for Designs 1-3

Design/Load	Mean $	StDev $	Minimum $	Maximum $
Design 1 700A	$796.7M	$37.6M	$683.8M	$923.8M
Design 2 700A	$777.6M	$37.7M	$667.2M	$893.8M
Design 3 700A	$820.8M	$38.1M	$697.4M	$954.3M

The sag difference was used to adjust the total structure cost to monetize the differences in sag performance. The space limitations preclude providing the data for all three designs, but information on design and simulation can be found in our paper [24]. Once the deterministic parameters of each line design are decided, uncertainties can be modeled with variance as certain fraction of the mean. Our current research is focused on finding accurate sources of data for uncertainty modeling. All three designs have been subject to TCO for three average loading levels (300 A, 500 A, and 700 A). Average load drives the line loss, which is the main source of differences in TCO over the 50-year time horizon of operating life using 2,000 samples of stochastic simulation. The Table II data are for the highest load level (700 A).

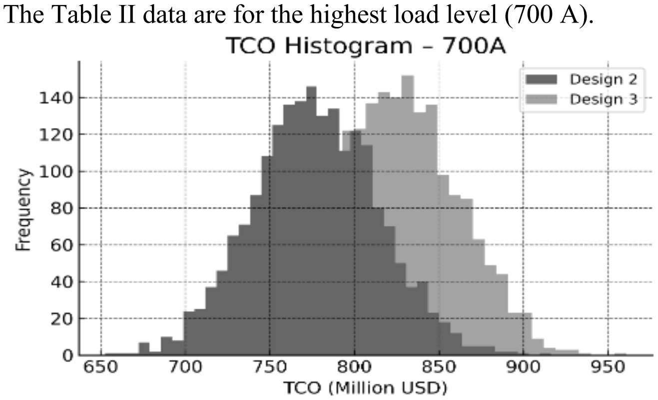

Figure 1. TCO histograms of *Design 2* (Falcon) and *Design 3* (Bittern).

A high-load average operating condition such as 700 A provides a meaningful basis for evaluating long-term economic and operational resilience across transmission line designs, because loss-related components of TCO scale exponentially with current magnitude. The 50th percentile TCO values offer insight into the deterministic, central-tendency financial expectation, while the 90th percentile quantifies the upper-bound risk exposure should unfavorable conditions materialize (e.g., higher material costs, higher inflation, or above-average line losses due to weather or system loading).

At the 50th percentile, the TCO values in Fig. 2 show a consistent ordering across the designs. *Design 2* (the advanced steel-core conductor) exhibits a lower expected TCO than *Design 1*, reflecting both a reduction in installed capital cost and improvements in performance under higher loading. *Design 3* (upper curve), the advanced composite core conductor), shows a moderate increase in median TCO relative to *Design 2* because of its higher first cost. Thus, at the median level, *Design 2* achieves the most favorable balance between capital cost and performance, with Design 3 offering an intermediate profile.

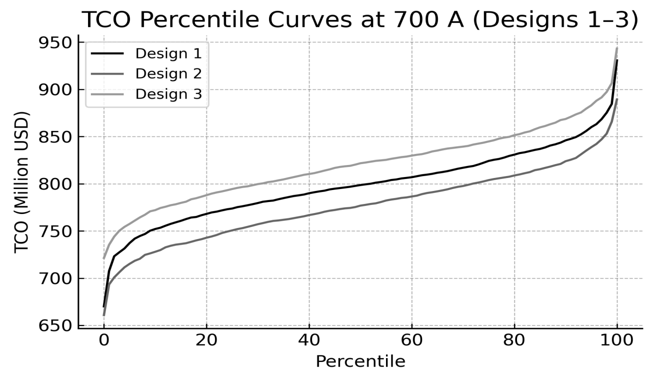

Figure 2. TCO percentile curves for all three line designs at the 700 A load.

The comparison becomes more revealing at the 90th percentile**,** reflecting scenarios with relatively high combined uncertainty—material cost escalation, weather-driven structural stress, and elevated line losses. Under these conditions, the TCO spread increases, and differences between designs become more pronounced. *Design 1* demonstrates the largest upward deviation from its median TCO, indicating that its conventional conductor and structure configuration are more sensitive to adverse conditions. *Design 2,* while economically efficient on average, shows a moderate widening of its upper percentile band—still tighter than Design 1 but broader than *Design 3*.

Taken together, the percentile comparison reveals that *Design 2* provides the lowest expected (median) TCO**,** and *Design 3* offers a smaller differential between the 50th and 90th percentiles. This distinction is relevant for transmission owners and regulators evaluating long-lived assets in regions such as Texas, where weather-driven uncertainty (e.g., extreme heat, icing events, and high wind loads) materially influences lifecycle costs. If capital efficiency is prioritized and risk tolerance is high, *Design 2* remains attractive alternative. This percentile-based perspective highlights the usefulness of stochastic TCO analysis in capturing uncertainty-driven differences that deterministic evaluations might overlook.

Design 2, with an advanced steel-core, typically shows a lower median (50th percentile) TCO than Design 3 at 700 A. That is consistent with the underlying economics: conductor and installation costs are lower, and the structures are designed around a familiar steel technology platform. In this example, losses are higher than in the composite design due to its slightly larger aluminum area. The difference is not enough—at the median scenario—to offset the capex advantage. In other words, if the world behaves "on average," *Design 2* is the more cost-efficient choice over 50 years.

Design 3, with composite-core conductors, typically exhibits a higher median TCO but a narrower spread,

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especially in the upper tail of distribution (90*th* percentile and beyond). The higher initial conductor cost is partially compensated by improved thermal performance, reduced sag at high temperatures, and somewhat lower losses at 700 A.

V. Conclusions

The integrated synthesis of the stochastic Total Cost of Ownership (TCO) offers potentially useful insights into design options and costs of important and expensive assets like transmission lines. The paper presents three 500 kV transmission line designs, representing three distinct technological and structural approaches to high-voltage transmission line construction under conditions typical of the southwestern United States, where climate-driven loading, rapid demand growth, and system resilience are major considerations. From Table II analysis of the mean TCO, Design 2 (ACSS) has an average TCO of \$777.6M amount vs \$820.8M for Design 3 (ACCC). A lower owning cost of \$43.2M over its 50-year life can be expected with (50 percent) probability.

Tariff and rate recovery analyses, planned to shape our future work, define the economically relevant TCO: which costs enter the revenue requirement, how capital is depreciated and earns return, how losses are treated, and how risk is allocated. Engineering-optimal designs must be assessed through recoverable costs and timing, not raw lifecycle expenditures. This cross-design comparison underscores the importance of stochastic modeling and analysis. Deterministic TCO obscures risk distributions and can lead to suboptimal design choices, especially when project justification depends on resilience, reliability, and life-cycle performance rather than first cost alone. The multi-design stochastic view equips planners and regulators with a risk-informed basis for investment decisions, which is the ongoing focus of this project, ensuring that transmission assets deployed today remain effective under the evolving operational conditions of the next five decades.

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