EXECUTIVE SUMMARY

Estimating the Costs of Major Storm Events

Literature Review of Major Storm Event Cost Estimation Practices and Models

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Core Argument

Major storm events are not simply operating emergencies for electric utilities — they are economy-wide disruptions that damage utility assets, interrupt customer activity, reduce productivity, create public safety risks, and expose how dependent modern communities are on continuous, high-quality electric service. Cost estimation must therefore move beyond a narrow accounting of poles, wires, crews, and overtime. A defensible estimate should combine direct utility restoration costs, customer outage costs, broader social and macroeconomic losses, and the expected benefits of resilience investments.

Traditional utility accounting remains essential for rate recovery, but direct utility costs do not represent the full damage a storm causes. The economy has changed: digital equipment, process controls, data centers, remote work, and just-in-time supply chains make both sustained outages and momentary power-quality disturbances more damaging than ever before — and this shift demands a broader measurement framework.

The Scale of the Problem

Weather-related power outages impose enormous economic costs on the United States:

- Federal estimates place the total annual cost of storm-related outages at between $20 billion and $55 billion.
- Between 2003 and 2012, weather outages cost the US economy $18–33 billion annually on average — spiking to $40–75 billion in 2008 (Hurricane Ike) and $25–70 billion in 2012 (Superstorm Sandy).
- Severe weather accounts for at least 58% of all US outages since 2002, and 87% of outages affecting 50,000 or more customers. An estimated 679 weather-related outages occurred between 2003 and 2012, according to the US DOE.
- Since 1980, the US has experienced 144 weather events each costing the economy over $1 billion.

A clear trend toward clustering of high-dollar storms, combined with rising population densities and growing interdependencies between the economy and critical infrastructure, is amplifying economic exposure to storm events over time.

What Should Be Counted: A Three-Category Framework

A complete storm-cost framework should distinguish among three categories of cost:

- Utility costs: damage assessment, labor, overtime, mutual aid, replacement assets, vegetation work, contractors, logistics, and lost sales revenue.
- Customer costs: inconvenience, spoiled goods, business interruption, idle labor and capital, shutdown and restart expenses, damaged equipment and inventory, backup power costs, and health and safety impacts.
- Wider social costs: emergency service disruption, transportation and communications impacts, tax revenue losses, reduced employment, effects on vulnerable customers, supply-chain cascades, and erosion of public confidence in critical infrastructure.

Customer costs vary significantly by sector, outage duration, time of day, season, advance warning, and backup capability — meaning a single average outage value can be highly misleading. Critically, traditional utility accounting treats customer economic disruption as a zero-cost externality, making it an incomplete baseline for public policy or regional resilience planning.

Traditional Damage Assessment Methods

Standard utility accounting procedures — governed by Generally Accepted Accounting Principles (GAAP) — form the foundation of any storm cost estimate. The post-storm workflow involves:

- Field damage assessment: documenting broken poles and crossarms, miles of lines replaced, transformers replaced, and total customer outages.
- Resource data collection: internal employee hours alongside invoices for external contractors, mutual aid crews, and vegetation management resources deployed during peak restoration.
- Weather data capture: wind speeds, rainfall, snow and ice accumulation — cross-referenced with regional weather databases for after-storm analysis and peer benchmarking.
- Restoration curve development: total days to restore, OSHA-reportable events, and customers restored per resource — benchmarked against industry peers.

Critically, data collection must begin before the storm. Restoration teams need clear cost codes, consistent time reporting, inventory tracking, weather documentation, and field assessment protocols established in advance. These records support rate recovery and serve as the foundation for future investment cases.

A useful storm cost estimate also separates historical accounting from forward-looking risk. Historical costs explain what happened during a given event; forward-looking estimates project what is likely under future storms and what can be avoided through investment. The strongest frameworks link storm records, customer value, and risk modeling rather than treating each event as an isolated emergency.

The Changing Socio-Economic Landscape

The technological transformation of industrial, commercial, and residential sectors has fundamentally altered power delivery requirements. Modern grid evaluation must treat power quality with equal weight to baseline availability:

- Automated industrial facilities, continuous manufacturing operations, and data infrastructure use complex processing systems susceptible to materials spoilage or systemic failure during brief voltage sags or momentary fluctuations.
- Momentary interruptions that historically went unrecorded now carry high financial penalties for digital-economy entities — a one-second outage averaged $1,477 per industrial or digital firm (EPRI/Primen, 2001).
- Residential vulnerability has risen materially: home offices, high-value appliances, and residential automation have elevated the baseline economic exposure of household consumers during standard outage events.

This shift has made the Value of Lost Load (VoLL) — defined as the economic value of electricity not delivered during an outage — the central metric for modern storm cost estimation.

The Value of Lost Load (VoLL) Framework

Core Concept and Dimensions

VoLL represents the value that customers attribute to a reliable and secure electricity supply, typically expressed in $/MWh or £/MWh. It is a multi-dimensional, context-specific metric. The source literature identifies key parameters including customer type, time of year, time of week and day, outage duration, and availability of advanced warning. VoLL should always be treated as a range, not a fixed number.

VoLL functions differently at different scales. Aggregate or average VoLL provides long-range guidance for generation and transmission planning, where estimating willingness to pay over extended periods is appropriate. Peak-period, segmented VoLL isolates localized vulnerabilities and directly informs operational scarcity pricing and targeted distribution engineering. VoLL can be used on both the planning side — studying costs and benefits of investment relative to customer willingness to pay — and the operations side, for resource adequacy rules and scarcity pricing algorithms.

Customer Class Cost Components

Outage costs differ fundamentally by customer class:

- Residential: driven by qualitative factors (inconvenience, stress, health and safety, lost leisure time) alongside direct out-of-pocket costs such as food spoilage and property damage.
- Commercial and Industrial: centered on idle capital, land, and labor; expensive shutdown and restart protocols; manufacturing scrappage; and complex downstream supply-chain multiplier effects.
- Infrastructure and Public Services: idle emergency service assets, blockages at public institutions, safety infrastructure disruptions, and potential social costs from looting and vandalism.

A critical pattern emerges across the literature: large industrial and commercial customers typically show a lower VoLL per MWh than small and medium enterprises — not because their absolute losses are smaller, but because higher continuous energy consumption means larger users consume more electricity per unit of gross value added, reducing the added value per unit of electricity. Additionally, larger companies are more likely to have invested in outage mitigation, further limiting their measured VoLL.

Key VoLL Study Results

Major empirical VoLL studies reviewed include:

- Great Britain (London Economics / Ofgem & DECC, 2013): Residential WTA ranged from £6,957–£11,820/MWh; WTP was significantly lower at £1,651–£2,766/MWh — figures based on a one-hour outage. The study recommends using WTA to capture the documented psychological asymmetry between loss aversion and willingness to pay for improvement. SME workday WTA VoLL reached £33,000–£39,000/MWh, driven by fixed shift structures and inability to defer tasks. Large industrial and commercial customers averaged approximately £1,400/MWh — lower than SMEs because high-volume energy use dilutes value added per unit consumed. The recommended aggregate VoLL — calculated as a load-share weighted average across residential and SME users for winter peak weekday figures — was £16,940/MWh.
- Texas / ERCOT (London Economics International, 2013): Using a GDP-to-load production function approach with state economic data segmented by NAICS classification codes, the study derived ERCOT-region VoLL ranges of $6,492–$7,438/MWh for commercial customers and $4,031–$4,619/MWh for industrial customers, based on 2011 GDP data.

Methodologies for Quantifying Outage Costs

Market-Based / Proxy Methods

These infer reliability value from observable customer behavior — investments in backup generation, uninterruptible power supplies, insurance, or premium reliability arrangements. They assume a rational-actor framework in which customers invest in backup capacity until the marginal cost of that protection equals the expected marginal cost of an unmitigated outage. Strengths: verifiable, requires minimal input data. Limitations: reveals little about temporal variance (duration and timing effects) or indirect losses, and may undercount customers who underinvest due to capital constraints.

After-the-Event Studies

Retrospective surveys ask customers to estimate actual losses following a real outage. Grounded in real experience, they can capture direct costs and local impacts. Limitations include recall bias, inconsistent customer records, difficulty valuing indirect losses, and the challenge of generalizing a single event's experience to future storms of different character.

Survey Methods

Surveys are the primary data source for customer outage costs and can be tailored to customer class, duration, season, warning conditions, and outage scenarios. Three configurations are used:

- Direct approach: customers self-calculate dollar losses for specific hypothetical interruption scenarios.
- Contingent valuation (WTP/WTA): customers state willingness to pay to avoid an outage or willingness to accept compensation for one. WTP is generally the more stable and accurate measure; WTA tends to be higher due to loss-aversion psychology.

- Contingent ranking / revealed preference: choice experiments presenting customers with service reliability and price combinations, from which econometric analysis derives marginal rates of substitution and WTP. This methodology is generally assumed to provide the upper limit for customer WTP.

Limitations include response bias, difficulty quantifying indirect supply-chain costs, and the WTA-vs-WTP gap. Surveys are expensive but remain the most widely used and accepted method for developing region- and utility-specific values, as they allow utilities to focus on the preferences and characteristics of their own customer base.

Macroeconomic and Non-Survey Alternatives

When primary data collection is unavailable, two secondary approaches are used:

- Consumer surplus / price elasticity methods: infer the value of reliability from long-term demand curves. Key constraint: reliance on monthly or annual data causes the model to systematically understate short-term customer adaptation during unplanned outages, and estimated demand elasticities may not be applicable during zero-consumption conditions.
- Production function / GNP or GVA-to-load ratio: divides a territory's Gross National Product or Gross Value Added by electricity consumption to derive an implied average VoLL. Useful for macro-level benchmarking but presumes a linear relationship between power delivery and economic output, introducing aggregation and substitution biases.

Lawrence Berkeley Laboratory Frameworks

LBL developed a series of increasingly sophisticated bottom-up models for estimating national outage costs over more than a decade of work:

- 2003 LBL Framework paper (24 studies, 8 utilities, 1989–2002): Used Tobit multiple regression models to develop Customer Damage Functions (CDFs) — establishing that outage costs scale non-linearly as duration extends from one to eight hours. Example outputs for a 1-hour summer afternoon outage: $3 per event for a residential customer, $1,200 for small-medium C&I, and $82,000 for large C&I customers.
- 2004 damage assessment framework: Estimated the national annual cost of power interruptions at $80 billion. The commercial and industrial sectors bore the majority of costs. Sensitivity analysis placed the range at $22–$135 billion.
- 2006 bottom-up analysis: Revised national estimate to $79 billion annually. The commercial sector accounted for more than 72% ($57 billion) of total outage costs; industrial nearly 26%; residential under 2%. Momentary outages (under 5 minutes) drove $52 billion of the total, with sustained outages accounting for the remaining $26 billion.
- 2009 meta-analysis (28 studies, 10 major utilities, 1989–2005): Used a two-part regression model — more accurate than prior approaches — to estimate Customer Damage Functions by season, time of day, day of week, and region, with costs expressed in 2008 dollars.

Power Quality and Momentary Interruptions

Power quality issues — voltage sags, harmonics, momentary interruptions — are systematically underestimated but can be as financially damaging as sustained outages:

- EPRI/Primen (2001): Industrial and digital economy companies lose a collective $45.7 billion annually at an average of $23,000 per business. A 1-second outage averaged $1,477 per firm; a 3-minute outage $2,107; and a 1-hour outage $7,795. Economy-wide outage losses ranged from $104–$164 billion annually, with an additional $6.7 billion lost annually by surveyed industrial and digital economy firms from power quality issues alone, and $15–$24 billion in total economy-wide power quality costs.
- BC Hydro (2005): Documented that 80% of business financial losses from power quality events stem from just 5% of problems occurring on the utility side of the meter. One automotive manufacturer cited a cost of $40,000 per momentary interruption incident, totaling $10 million per year across all plants, from the need to restart assembly lines, boilers, air compressors, and re-program controls alone.

Because 95% of power quality problems arise on the customer side of the meter, utilities have historically underweighted them in reliability statistics. Yet the financial losses they cause — particularly from voltage sags triggering manufacturing shutdowns — frequently exceed those from sustained outages.

Using Costs for Planning: Cost–Benefit Analysis

Customer outage cost methodologies, when systematically adopted, transform grid investment decisions. Value-Based Reliability Planning (VBRP) evaluates hardening, undergrounding, smart grid systems, distribution automation, distributed generation, flood mitigation, and vegetation management by comparing life-cycle costs with the economic value of avoided outages.

VBRP helps utilities avoid two costly mistakes: over-building a system to a reliability level customers would not pay for, and under-building so that customers bear more outages than they are willing to tolerate. A strong planning process ranks candidate investments by reductions in outage hours, unserved energy, restoration costs, and customer losses — evaluated over the asset's life using realistic assumptions about storm frequency, climate exposure, load growth, and uncertainty. Key case studies from the literature include:

- PSE&G Energy Strong Program: A $3.9 billion hardening and resilience program (of which $2.8 billion was for the distribution system) broke even at approximately 3.08 days of avoided cumulative outage. The average duration across Sandy (3.5 days), Hurricane Irene (0.83 days), and the 2011 October snowstorm (0.94 days) was nearly 5.3 days — well above the break-even point. A separate macroeconomic analysis estimated that outages during Sandy caused $12 billion in lost economic activity, 7,300 job losses, reduced tax revenues, and higher government costs.
- Halifax Undergrounding Study (2007): Undergrounding avoided storm-related customer losses of $42–$218 per customer for a 100-year storm event. The estimated economic cost of undergrounding was approximately $3,800 per lot, but with non-economic benefits included (reduced outage frequency and duration, improved aesthetics, increased property value), the estimated net benefit rose to approximately $10,000 per lot.
- Florida Undergrounding Analysis (2007): A Monte Carlo hurricane simulation model estimated the state could have saved $50 billion in 2004–2005 if undergrounding had been completed prior to those storm seasons.
- Illinois JITKA Program: Distributed generation installed at just-in-time manufacturing sites — where outages cost $300,000–$600,000 per hour — provided credits of approximately $150,000 over a five-year period, about one-third of each installation's cost. Ten key accounts totaling 20 MW were served under the program.

Break-even analysis is especially useful for regulators: rather than defending a precise benefit estimate, utilities can demonstrate how many hours of avoided outage are needed over the asset's life for customers to receive value equal to or greater than the investment cost.

Storm Damage Prediction

Storm-cost estimation should become predictive rather than solely retrospective. Predictive models connect weather forecasts, asset characteristics, system topology, vegetation exposure, and historical outage data to estimate likely damage before and during an event — enabling crew pre-staging, mutual-aid requests, material planning, and customer communications. Key models in the literature include:

- Statistical hurricane outage models: Using negative binomial generalized linear regression, these predict customer outage counts, damaged poles and transformers, and component failure probability from wind speed, soil moisture, precipitation, land cover, and system topology. Replacing storm-specific binary variables with physically measurable inputs enables genuine predictive use across novel storm scenarios.
- PSE&G / Rutgers meteorological damage prediction model: A perfect-prognosis regression model with 144 equations across four service territories, six plant elements, and six storm modes — generating tiered weather alerts correlating storm conditions to expected plant damage, validated against an independent PSE&G dataset.
- Sperry-Piltz Ice Index (NOAA / Oklahoma Association of Electric Cooperatives): Categories five levels of ice damage potential using radial ice thickness and wind speed. After systematic evaluation from 1994 data onward, it became fully operational between November 2014 and April 2015.

- Florida Hurricane Simulation Model: A collaborative Monte Carlo simulation tool modelling full hurricane seasons and the distribution of damage to overhead vs. underground infrastructure — enabling targeted, evidence-based hardening investment with a scenario-testing capability for historical storms.

Predictive modelling also improves the feedback loop after each event. Utilities should compare predicted damage with actual outcomes, review restoration curves, update fragility assumptions, and capture lessons from crews, mutual-aid partners, and customers. Each major storm, handled this way, produces better risk models, better operating plans, and stronger future investment cases.

Rate Recovery Mechanisms

Recovering storm costs requires navigating regulatory mechanisms with different speed, risk, and ratepayer implications. The key mechanisms are:

- General rate case recovery: standard but slow; subject to political compromise and credit-rating risk during delays. Useful for approved capital expenses such as storm hardening, but less suited to unpredictable storm costs.
- Cost deferral: allows utilities to place large costs on the balance sheet as a regulatory asset for recovery in a future rate case, avoiding immediate ratepayer shock.
- Rate adjustment mechanisms (riders/trackers): temporary or permanent surcharges approved outside the normal rate case cycle — increasingly popular for their speed, transparency, and ability to restore investor confidence.
- Storm reserve accounts: utility self-insurance funded by accrual; effective for moderate events but often insufficient for catastrophic storms. Some regulators allow accounts to carry a negative balance during particularly severe events.
- Securitization: state-backed bonds at lower interest rates, enabling cost-effective financing for large recovery or hardening programs, though administrative costs can be high.
- Federal funding: FEMA and HUD Community Development Block Grant (CDBG) programs are available for public and non-profit utilities; investor-owned utilities are generally excluded under the Stafford Act.

Pennsylvania Power & Light's Storm Damage Expense Rider (SDER) illustrates best practice: a formula-based calculation separates recoverable storm costs from normal operating expenses, applied to all reportable storms lasting at least six hours with at least 2,500 outages, with recovery capped at 3% of total intrastate operating revenues and subject to periodic audit by the commission.

Key Findings & Recommendations

The literature converges on ten overarching recommendations for utilities, regulators, and policymakers:

- Adopt a layered cost framework that separately tracks direct utility costs, customer outage costs, public-sector impacts, and wider economic losses — using accounting data for cost recovery and valuation methods for benefit estimation.
- Transition from Cost-of-Service to value-based regulatory frameworks: public utility commissions should link utility revenue authorization to the explicit service quality that customers demonstrate they are willing to fund, using VoLL data to set and enforce reliability targets.
- Treat VoLL as a context-specific range, not a point estimate — adjusted for customer class, timing, duration, season, warning, and backup capability. Aggregate VoLL is appropriate for generation and transmission planning; segmented peak-period VoLL is required for distribution investment and operational scarcity pricing.
- Deploy non-linear regression models (particularly Tobit-based Customer Damage Functions) in resilience planning — linear damage assumptions systematically underestimate costs as outage duration grows.
- Implement standardized customer surveys using consistent design and sampling practices across utilities, to build regional data compatibility and reduce the wide uncertainty ranges in current VoLL estimates. Consistent methodologies enable valid meta-analysis across studies.

- Leverage commercial insurance industry data streams as an objective cross-check on willingness-to-pay models: insured loss data for business interruptions, infrastructure damage, and equipment losses provides independently verified cost evidence that is generally more rigorous than other estimates.
- Expand MAIFI tracking and power quality monitoring; include momentary interruptions and voltage sags in cost–benefit analyses, particularly for digital, industrial, and process-manufacturing customers where these events frequently exceed the cost of sustained outages.
- Build predictive damage models combining weather, asset, vegetation, topology, customer, and historical outage data — for both pre-storm operations and long-term investment planning. Use break-even analysis to make investment cases defensible to regulators.
- Encourage broad data sharing: regulators should incentivize utilities to contribute anonymized outage and valuation studies to a national meta-database, increasing the statistical power of predictive models and enabling more accurate customer damage benchmarks. Utilities are often reluctant to share data due to litigation risk, but the literature suggests this risk is minimal.
- Improve outage communication, mutual-aid planning, and protection of vulnerable customers as relatively low-cost resilience measures. Treat each major storm as a learning opportunity: compare predictions to outcomes, update models, and use findings to strengthen the next investment case.

The central lesson is that storm-cost estimation should become a forward-looking decision tool, not merely a post-event accounting exercise. A defensible framework links event data, customer value, predictive risk modelling, and cost–benefit analysis — helping utilities target investments where they reduce the most harm, helping regulators judge whether costs are justified, and helping communities build a genuinely more resilient electric system.