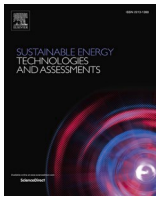
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Economic and climate implications of diesel backup power in outage-affected countries

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ABSTRACT

Chronic electricity outages can shift the burden of unreliable grid supply to local backup generation, yet cross-country evidence on the scale and consequences of this shift remains limited. This study develops a harmonized framework for 56 outage-affected countries that links reported outage exposure, power-system scale, and empirical seasonal demand factors to retained-demand scenarios, and evaluates the consequences of supplying the resulting backup-electricity requirement with a standardized diesel benchmark. Using source observations with their documented reference years retained (WBES outages: 2006–2024; power-system and grid-lifecycle data: 2022–2024; monthly demand: 2024; diesel-price and exchange-rate evidence: 2025), the R20 reference modeling scenario (20% retained demand) yields an expected annual backup-electricity requirement of approximately 4.275 TWh across the 56-country sample. At a reference generator efficiency of 35%, diesel fuel-cycle emissions are estimated at 3.971 $MtCO_2e$/year, compared with 2.123 $MtCO_2e$/year for the corresponding grid lifecycle counterfactual, yielding a net additional climate burden of 1.849 $MtCO_2e$/year. For the 26 countries with complete matched diesel-price, grid-tariff, and exchange-rate evidence, the net avoidable operating-energy cost is USD 306.9–484.4 million/year, where the range reflects admissible tariff branches rather than probabilistic uncertainty. Country-level empirical P05–P95 ranges describe seasonal variation, while retained demand, generator efficiency, tariff evidence, and upstream diesel pathways are evaluated separately as scenario, sensitivity, and structural-robustness dimensions. The results reveal strong cross-country heterogeneity and show that aggregate burden and per-unit impact structure do not necessarily move together. The framework provides a transparent benchmark for comparing outage-driven diesel burdens and for future assessment of resilience and lower-emission backup transitions without relying on composite vulnerability scores or policy-priority thresholds.

Introduction

Global electricity demand increased by 4.3% in 2024, nearly double the average annual growth of the previous decade, with most of the increase occurring in emerging economies [1]. This expansion, driven by record temperatures, industrial growth, transportation electrification, and data center proliferation, is projected to continue at approximately 4% annually through 2027 [1]. While renewable and nuclear generation continue to expand, this rapid demand growth coincides with persistent reliability challenges across both developing and advanced economies [1].

Power-system reliability is also increasingly exposed to extreme weather, infrastructure stress, and other disruptions [2,3]. These outages generate cascading economic, health, and climate-related consequences. Previous studies have quantified environmental impacts from backup generation during outages [4], documented health consequences ranging from acute poisoning to interruption of electrically dependent medical care [5] and shown that financial losses vary substantially with industrial characteristics, consumer scale, and disruption duration [6]. These effects make continuity of electricity service, rather than nominal access alone, an important dimension of energy-system resilience.

Power outages and electricity access challenges

The electricity reliability challenge manifests differently across

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regions and development contexts, but in many outage-affected countries it creates persistent constraints on productivity, welfare, and structural transformation. In Sub-Saharan Africa, where many economies remain highly dependent on micro, small, and medium-sized enterprises, repeated outages reduce output, increase operating costs, disrupt supply chains, and weaken income-generating capacity [7]. These effects are reinforced where electricity access remains incomplete or service quality remains poor. Even in contexts where nominal access has expanded, unreliable supply can still undermine the developmental value of electrification by limiting continuity of service, discouraging productive electricity use, and increasing the cost of maintaining basic operations [8].

The consequences of unreliable electricity are also unevenly distributed. Existing evidence shows that outage impacts are shaped by socioeconomic conditions, location, and dependence on electrically mediated services, with vulnerable households and communities often facing disproportionate exposure to service disruption and its secondary effects [9,10]. At the same time, climate-related hazards can intensify these risks by damaging electricity infrastructure or constraining power-system operation [2,3]. Together, these patterns indicate that electricity access alone is not sufficient as a proxy for energy security or developmental progress. What also matters is whether electricity can be supplied with enough continuity and reliability to support economic and social activity under disrupted conditions.

Backup power solution

In practice, diesel generators remain widely used for backup power in many outage-affected systems because they are modular, dispatchable, and supported by established fuel-supply and maintenance practices. This continued dependence persists despite the well-recognized environmental and operational disadvantages of diesel-based backup. Recent studies show that alternative technologies and hybrid configurations, including photovoltaic (PV) battery combined heat and power (CHP) systems, PV/battery systems, fuel cells, and PV-diesel or PV-diesel-biogas systems, can improve outage survivability or reduce cost and emissions under specific operating conditions [11–16]. However, their performance and feasibility remain strongly dependent on application-specific load characteristics, outage duration, local resources, capital cost, and system configuration.

As a result, backup-power research has increasingly focused on optimization at the facility or sector level, such as hospitals and other critical or electricity-dependent operations [11–16]. These studies provide important insight into technology substitution and system design, but they do not answer a broader cross-country question: what are the economic and climate implications of supplying outage-driven backup-electricity requirements with a common diesel benchmark when chronic outages affect national electricity systems at scale? Addressing this question requires moving beyond single-application case studies and developing a harmonized framework capable of comparing outage-driven backup burdens across heterogeneous national contexts.

Diesel is therefore used in this study as a standardized analytical benchmark rather than as an assumption that diesel supplies all real-world backup electricity in every country. The benchmark provides a common conversion pathway from backup-electricity requirements to fuel use, operating-energy cost, and fuel-cycle greenhouse-gas emissions. Alternative backup technologies remain important transition pathways, but direct comparison among them requires technology-specific capital, operating, availability, and lifecycle boundaries that are outside the scope of the present cross-country analysis.

Research gaps and objectives

Cross-country evidence on backup-generation burdens remains limited but is not absent. Farquharson et al. [17] quantified diesel-backup costs, emissions, and fossil-energy use across sub-Saharan Africa, while the IFC [18] modeled the generator footprint across 167 modeled countries. The gap addressed here is a harmonized outage-to-backup framework linking reported outage exposure and power-system demand to explicit retained-demand scenarios, empirical seasonal support, matched tariff evidence, and country-specific grid lifecycle counterfactuals.

This study addresses this gap by developing a harmonized cross-country assessment framework and applying it to a 56-country sample with persistent power disruptions. The framework combines reported outage exposure, electricity-system scale, and empirically derived seasonal demand factors to estimate backup-electricity requirements under five retained-demand scenarios. It then evaluates a standardized diesel benchmark through two distinct outcomes: net avoidable operating-energy cost for the countries with complete matched price and exchange-rate evidence, and net additional climate burden across the full sample under consistent diesel fuel-cycle and grid lifecycle accounting boundaries.

The analysis further separates empirical seasonal variation from retained-demand and generator-efficiency sensitivity and from structural evidence ranges associated with electricity tariffs and upstream diesel pathways. By retaining economic and climate outcomes in their original physical and monetary units, the study provides a transparent comparative benchmark for interpreting different backup-burden structures without relying on composite vulnerability scores or policy-priority thresholds.

Methodology

Analytical framework

This study develops a harmonized cross-country framework to quantify the economic and climate implications of outage-driven diesel backup power in outage-affected countries. As shown in Fig. 1, the framework comprises four analytical layers: system inputs, demand estimation and outage modeling, impact quantification, and analytical outputs. Country-level outage statistics, power-system indicators, monthly system-demand proxy information, and price and emission parameters are first assembled. Observed 2024 monthly system-demand proxy data from six reference countries are converted into normalized seasonal factors. Following estimator validation, pooled empirical seasonal factors are transferred to countries without monthly observations. These demand characteristics are combined with five retained-demand scenarios (R05–R40), with R20 used as the reference modeling scenario, to estimate annual backup electricity requirements from empirical outage-load support.

Backup electricity is subsequently converted into diesel consumption and evaluated through separate economic and climate pathways. The economic pathway compares diesel fuel operating cost with the matched grid variable cost of delivering the same quantity of electricity, while the climate pathway compares diesel fuel-cycle greenhouse-gas emissions with the corresponding grid lifecycle counterfactual. The analytical-output layer explicitly separates empirical seasonal variability from scenario and structural robustness. Country-level uncertainty is summarized using empirical percentile statistics and relative interquartile range, whereas retention, generator efficiency, admissible tariff branches, and upstream diesel pathways are examined through sensitivity and robustness analysis. Cross-country results are then interpreted through country heterogeneity and direct economic-climate comparative mapping, without assigning composite severity scores or probabilistic weights to structural price branches.

Country sample, data sources, and system-level indicators

The study focuses on countries experiencing recurrent electricity outages for which the required outage and power-system information could be assembled consistently. Country-level outage frequency and

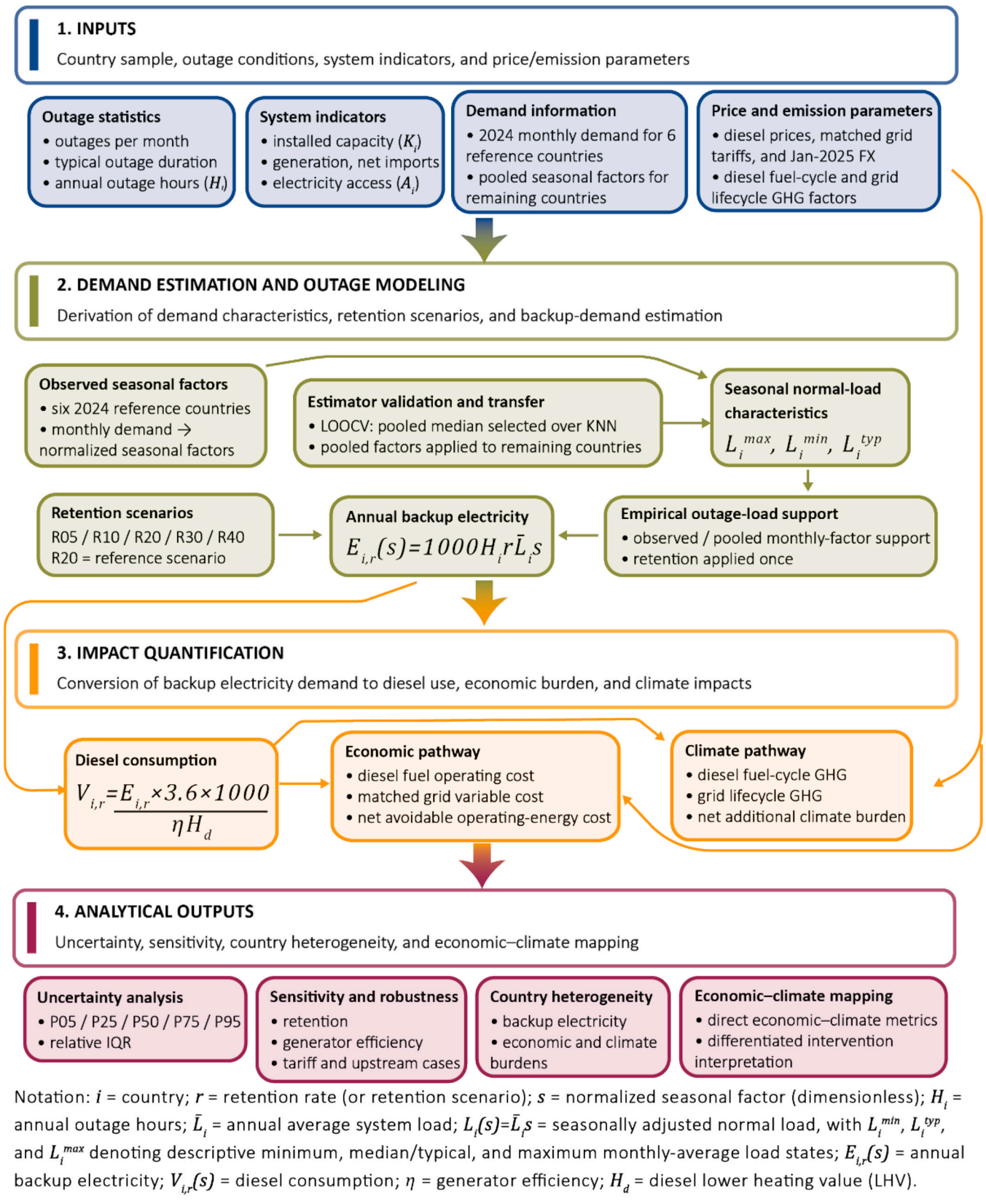


Fig. 1. Analytical framework for quantifying the economic and climate implications of outage-driven diesel backup power. The framework comprises four layers: inputs, demand estimation and outage modeling, impact quantification, and analytical outputs. Observed 2024 monthly demand from six reference countries is used to derive seasonal factors, with pooled empirical factors transferred to the remaining countries following estimator validation. Five retained-demand scenarios (R05–R40) are evaluated, with R20 used as the reference modeling scenario. Backup electricity is translated into diesel consumption, net avoidable operating-energy cost, and net additional climate burden. Analytical outputs include empirical percentile-based uncertainty, sensitivity and robustness analysis, country heterogeneity, and direct economic–climate comparative mapping.

typical outage duration were obtained from the World Bank Enterprise Surveys (WBES) [19], resulting in a final analytical sample of 56 countries. Importantly, the WBES observations do not correspond to a common calendar year: the survey waves represented in the sample span 2006–2024, with a median survey year of 2018.5. The original survey year is therefore retained for each country rather than treating the outage observations as contemporaneous measurements. Electricity access is represented using the 2023 World Bank indicator [20], while annual installed capacity, electricity generation, and net electricity imports are obtained from the Ember yearly electricity dataset [21]. Population estimates for 2025 are retained only as contextual information and do not enter the core backup-electricity, economic, or climate calculations. The six monthly-demand datasets used for seasonal-demand characterization correspond separately to 2024 and are described in Section 2.3.

To harmonize the electricity-system quantities used across countries, annual system demand is defined as the accounting proxy $D_i = G_i + N_i$ using Ember annual electricity inputs [21], where G_i is annual electricity generation and N_i is net electricity imports for country i. The corresponding annual average system load is $\overline{L}_i = 1000D_i/8760$, where D_i is expressed in TWh and $\overline{L}_i$ in GW. Installed-capacity utilization is $U_i = 1000G_i/(8760K_i)$, where K_i is installed generation capacity in GW [21]. Annual outage exposure is annualized from the WBES typical-month indicators as $H_i = 12f_id_i$[19], where f_i is reported outages in a typical month and d_i is typical outage duration in hours. These are study-defined accounting transformations applied to the cited source variables; they standardize units and definitions across countries but do not imply temporal synchronization.

Because complete historical series were not available for all input variables, the analysis does not retrospectively interpolate national observations to a common reference year. Instead, source observations are retained according to their documented temporal coverage, while common definitions and units are applied across countries. This approach avoids synthetic historical values but leaves residual temporal heterogeneity. A survey-year diagnostic is therefore conducted in Section 2.6, while temporal asynchrony remains an explicit limitation.

Finally, the WBES indicators are derived from country- and survey-wave-specific firm samples and describe firms' reported experience of a typical month and typical outage duration rather than continuously metered interruption records. Reporting differences, omission of short or less disruptive interruptions, and recall error cannot be ruled out. No ex-post correction factor is imposed because a consistent country-level correction is not empirically identifiable for the full sample. Country-level source years and system inputs are reported in Supplementary Table S1.

Estimation and validation of seasonal normal-load characteristics

Detailed monthly system-demand proxy information is unavailable for most countries in the sample. Six countries-Bangladesh, Dominican Republic, Kenya, Nigeria, Pakistan, and South Africa-have complete monthly electricity data for 2024 [22] and are used as reference systems for seasonal-demand variation. Using these Ember monthly data [22], monthly average load is defined as $L_{i,m} = 1000E_{i,m}/h_m$ and annual average load as $\overline{L}_i = 1000\Sigma E_{i,m}/8784$ for each reference country i and month m. The 8784-h denominator is used because 2024 is a leap year; this differs from the 8760-h annual convention used for the cross-country system-load proxy in Section 2.2 and does not affect normalization of the observed monthly profiles. The normalized seasonal factor is $s_{i,m} = L_{i,m}/\overline{L}_i$. Here, the monthly electricity-demand quantity is expressed in TWh and the month length in hours; the factor of 1000 converts TWh/h to GW.

The month-hour-weighted annual mean of $s_{i,m}$ equals unity. Descriptive minimum, typical, and maximum factors are defined as $min(s_{i,m})$, $median(s_{i,m})$, and $max(s_{i,m})$, respectively. These quantities represent monthly-average seasonal operating states rather than instantaneous minimum, peak, or modal electricity demand. The corresponding descriptive minimum, typical, and maximum monthly-average load states shown in Fig. 1 are obtained by applying these factor descriptors to the annual average load.

Estimator choice was evaluated using leave-one-country-out cross-validation (LOOCV) across the six reference countries. The pooled-median estimator achieved mean absolute error (MAE) = 0.0672 and root mean squared error (RMSE) = 0.0907, compared with MAE = 0.0732 and RMSE = 0.0998 for the best tested k-nearest-neighbor (KNN) configuration (k = 3). Because the pooled estimator provided lower prediction error with a substantially simpler structure, it is used for countries without directly observed monthly profiles.

The six reference countries retain their observed seasonal factors, while the remaining 50 countries use pooled median descriptors. The pooled factors are 0.867 for minimum, 0.997 for typical, and 1.115 for maximum. These descriptors characterize monthly-average seasonal normal-load states only; the full empirical monthly-factor support is retained for uncertainty treatment in Section 2.4. Observed seasonal factors and the LOOCV estimator comparison are reported in Supplementary Table S2.

Retained-demand scenarios and empirical backup-demand uncertainty

The retained-demand rate r represents the fraction of normal electricity demand assumed to remain active during an outage. Because harmonized cross-country observations of outage-period demand retention are unavailable, retained-demand levels are treated as modeling scenarios rather than empirically observed national parameters. Five scenarios are considered: R05, R10, R20, R30, and R40, corresponding to 5%, 10%, 20%, 30%, and 40%. R20 is the reference modeling scenario; it is not interpreted as an average or typical national retention rate. Context-specific critical-load planning and resilience studies support treating retained demand as a scenario quantity rather than a universal national coefficient [23–25].

For country i, retention scenario r, and seasonal factor s, the study defines retained outage-period load as $L_{i,r}(s) = r\overline{L}_{is}$ and annual backup electricity as $E_{i,r}(s) = 1000H_{ir}\overline{L}_is$. The literature cited above [23–25] is used only to establish that critical-load fractions are context dependent; it is not used to calibrate R05–R40 as national observations. Retained demand therefore enters the backup-electricity calculation once only.

Seasonal uncertainty is represented using empirical monthly-factor support rather than a parametric distribution. The six reference countries use their own 12 observed 2024 monthly factors weighted by month hours. The remaining 50 countries use a pooled 72-factor support with equal total weight for each reference country and month-hour weighting within each country.

Because normalized seasonal factors have an hour-weighted expectation of one, expected annual backup electricity is $E[E_{i,r}] = 1000H_{ir}\overline{L}_i$. Weighted empirical percentiles are obtained directly from the exact inverse empirical cumulative distribution function of the discrete monthly-factor support. No parametric fitting or random resampling is performed. P05, P25, P50, P75, and P95 are reported at country level, and the relative interquartile range (RIQR) is (P75 − P25)/|P50|. Global Pxx values are not reported because cross-country dependence is not specified; global values are sums of expected country-level values only. Scenario definitions and empirical seasonal support are summarized in Supplementary Table S3.

Economic and climate impact quantification

Diesel consumption and net operating-energy cost

Generator electrical efficiency is set to 35% in the reference calculation, with 25–45% used as a deliberately broad sensitivity envelope spanning efficiencies reported across generator scales and loading

conditions [26–28]. Because actual diesel-generator efficiency depends on loading, unit size, operating condition, and maintenance, 35% is treated as a harmonized analytical reference rather than a country-specific performance estimate. A diesel lower heating value of 35.8117 MJ/L is used [29]. Annual backup electricity is converted into diesel consumption as $V_{i,r} = (3.6 \times 1000 \times E_{i,r})/(\eta\, H_d)$, where $E_{i,r}$ is in MWh, $V_{i,r}$ is in liters, η is generator electrical efficiency, and H_d is the diesel lower heating value in MJ/L. When seasonal variation is retained explicitly, the same conversion is applied to each seasonal realization; expected diesel consumption is obtained by applying the equation to the expected backup-electricity requirement.

Diesel operating cost is defined as $C_{diesel} = V \times P_{diesel}$ and matched grid variable cost as $C_{grid} = 1000E \times P_{grid}$. The principal economic metric is $C_{net} = C_{diesel} - C_{grid}$, termed net avoidable operating-energy cost. Positive values mean diesel fuel operating cost exceeds matched grid variable cost; negative values mean the opposite within the defined operating-energy comparison. These are accounting identities applied to the price evidence described below, not lifecycle, social-cost, or investment equations. The diesel-price term is expressed in USD/L and the matched grid-tariff term in USD/kWh; diesel, grid, and net operating-energy costs are expressed in USD.

Diesel-price evidence is taken from the World Bank Global Fuel Prices Database (April 2025) [30], while matched grid-tariff evidence is retained according to documented tariff structure. Local-currency observations are converted with the World Bank Global Economic Monitor January 2025 period-average exchange rate [31] where required. Lower and upper admissible tariff branches are propagated directly; no midpoint or branch probability is assigned. The resulting range is an evidence-constrained structural tariff range, not a confidence interval.

Primary economics are restricted to 26 countries with jointly complete diesel-price, grid-tariff, and foreign-exchange (FX) evidence. No synthetic substitution is introduced for incomplete countries. Capital cost, maintenance expenditure, start-up reliability, fuel-storage infrastructure, and fuel-resupply constraints are outside the primary monetized boundary; O&M is tested separately in Section 2.6. The results therefore represent an availability-unconstrained diesel benchmark conditional on generator operability and sufficient fuel supply; no universal availability derating factor is imposed. Country-level price evidence, tariff branches, FX treatment, and economic eligibility are summarized in Supplementary Table S6.

Fuel-cycle climate impact

Climate impacts compare diesel fuel-cycle greenhouse-gas intensity with the national grid lifecycle greenhouse-gas intensity of the same delivered backup electricity. The diesel boundary includes upstream diesel production and stationary combustion but excludes generator manufacturing, transport, infrastructure construction, and end-of-life.

Diesel fuel-cycle intensity is constructed from R&D GREET 2024 upstream conventional-diesel greenhouse-gas (GHG) factors [32] and Intergovernmental Panel on Climate Change (IPCC) stationary-combustion factors for CO_2, CH_4, and N_2O [33], with CH_4 and N_2O converted to CO_2-equivalent using Sixth Assessment Report (AR6) 100-year global-warming-potential (GWP100) values [34]. The US upstream pathway is the standardized reference, while Chile and California are robustness cases. The resulting combustion total is 74.5338 gCO_2e/MJ LHV and the US fuel-cycle total is 90.3200 gCO_2e/MJ LHV.

At the 35% reference efficiency, the resulting diesel electricity-specific fuel-cycle climate intensity is 929.006 gCO_2e/kWh. Country grid lifecycle intensities are taken from the harmonized Our World in Data/Ember lifecycle series [35]. For each country, diesel, grid, and net additional climate burdens are calculated from backup electricity and the corresponding climate intensities; with backup electricity E in MWh and climate intensity CI in gCO_2e/kWh, the conversion is $tCO_2e = E \times CI / 1000$.

The climate formulation is applied to all 56 countries. Country seasonal Pxx values are propagated by exact monotone transformation of the empirical backup-electricity quantiles defined in Section 2.4. Fuel-cycle parameters and country grid lifecycle intensities are reported in Supplementary Tables S4 and S5.

Sensitivity, validation, and comparative analysis

Sensitivity and structural robustness

The robustness assessment distinguishes empirical seasonal variability from sensitivity to modeling assumptions and structural evidence choices. Retained demand is evaluated across R05–R40 and generator efficiency across 25–45%, with R20 and 35% as reference values. An auxiliary O&M sensitivity adds USD 0.03–0.06/kWh to diesel-side cost in 0.01 increments, spanning ESMAP combined O&M estimates for 100 kW to 5 MW diesel units [26]; zero O&M remains the primary benchmark.

Economic robustness retains admissible tariff lower/upper branches without midpoint or probability. Climate robustness uses the US GREET upstream pathway as the standardized reference and Chile/California as alternative upstream cases. Economic sensitivity is based on the matched 26-country sample; when economic and climate sensitivity are presented side by side in Fig. 3, the same 26-country subset is used for direct comparability.

Validation and data-heterogeneity diagnostics

Modeled R20 backup reliance is compared with observed WBES generator ownership. The validation quantity is defined as the expected R20 backup-electricity requirement divided by annual system demand, $B_i = \mathbb{E}[E_{i,R20}]/(10^6 D_i) = 0.20H_i/8760$, where D_i is annual system demand in TWh. Because R20 is fixed across countries and the empirical seasonal-factor expectation equals one, the cross-country rank ordering of B_i is identical to that of annual outage hours. The diagnostic therefore tests whether the outage-exposure component of the framework is directionally consistent with observed generator adoption; it does not validate absolute backup-electricity magnitudes, the seasonal-demand transfer, or the retained-demand fraction. Spearman and Kendall rank correlations are reported, and generator ownership is summarized across quartiles of modeled backup reliance. Because outage statistics and generator ownership originate from the same WBES survey wave, this is a partial validation using an external observed indicator rather than independent absolute validation.

Survey year is correlated separately with annual outage hours and expected R20 backup electricity using Spearman rank correlation. This diagnostic tests for a monotonic survey-year pattern but is not a temporal correction. Country survey years remain unchanged and residual temporal heterogeneity remains a limitation. Detailed generator-ownership and survey-year diagnostics are reported in Supplementary Table S10.

Country heterogeneity and economic–climate comparative mapping

Country heterogeneity is evaluated using direct physical, economic, and climate quantities rather than normalized composite scores. Under R20, the analysis compares expected backup electricity and empirical P05–P95 across all 56 countries, net additional climate burden and climate-intensity differences across the same 56-country sample, and net avoidable operating-energy cost across the 26-country matched economic sample.

The final comparative mapping uses the matched 26-country sample. The aggregate view compares net avoidable operating-energy cost with expected net additional climate burden; the unit-impact view compares net operating-energy cost per backup kWh with the diesel fuel-cycle-grid lifecycle climate-intensity difference. Admissible tariff branches remain horizontal structural ranges, while expected R20 backup electricity provides system-scale context. No 0–100 normalization, composite severity index, categorical priority threshold, or probabilistic tariff

weighting is applied.

Results

The results are presented in four stages. First, the 56-country sample is positioned within the joint landscape of electricity access, outage exposure, grid utilization, and R20 backup-power requirements. Second, the sensitivity of the economic and climate outcomes to retained demand and generator efficiency is evaluated together with structural robustness to tariff evidence and upstream diesel pathways. Third, country-level heterogeneity and empirical seasonal uncertainty are examined separately for backup electricity, economic burden, and climate burden. Finally, the matched economic–climate sample is synthesized using direct aggregate and unit-impact metrics rather than normalized composite scores or policy-priority classes.

This sequence separates the physical scale of outage-driven backup requirements from the subsequent economic and climate consequences. Unless otherwise stated, R20 denotes the reference modeling scenario rather than an empirically observed national retention rate. Economic results refer to the 26 countries with complete matched price and exchange-rate evidence, whereas backup-electricity and climate results retain the full 56-country sample.

System-level outage and backup-power landscape

Fig. 2 provides the system-level context for the subsequent impact analysis by jointly comparing electricity access, annual outage exposure, grid-capacity utilization, and the retained backup load required under the R20 reference scenario. Across the 56 countries, annual outage exposure ranges from 2.16 to 2,862 h/year. The typical R20 retained backup load corresponds to approximately 1.91–29.58% of installed generation capacity. This ratio is used only as a visualization metric in Fig. 2 and is not interpreted as an estimate of installed national backup capacity.

The cross-country distribution shows that electricity access and outage exposure represent distinct dimensions of power-system conditions. High nominal access does not necessarily imply low interruption exposure, while some lower-access systems combine severe outages with comparatively small electricity-system scale. Consequently, outage duration alone does not determine the absolute backup-electricity requirement. The same outage exposure can translate into substantially different backup requirements depending on the underlying system load, while grid-capacity utilization provides an additional indication of how intensively existing generation infrastructure is used. Under R20, expected annual backup electricity across the full 56-country sample is approximately 4.275 TWh/year.

As a partial consistency check of the outage-exposure component of the framework, the expected R20 backup-electricity share was compared with the corresponding WBES generator-ownership indicator across all 56 countries. Generator ownership was positively associated with modeled backup reliance (Spearman's $\rho = 0.434$; Kendall's $\tau = 0.299$), and mean ownership increased from approximately 36.7% in the lowest quartile of modeled reliance to 54.4% in the highest quartile. Because the modeled share has the same cross-country rank ordering as annual outage hours under fixed R20, this association supports relative consistency between modeled outage exposure and observed generator adoption rather than validating absolute backup-electricity requirements, retained-demand levels, or the seasonal-demand transfer. A separate survey-year diagnostic showed weak monotonic associations between WBES survey year and annual outage exposure ($\rho = -0.209$) and between survey year and expected R20 backup electricity ($\rho = -0.001$). These diagnostics do not remove the underlying temporal heterogeneity of the source data, which remains a limitation. Detailed validation results are reported in Supplementary Table S10.

Fig. 2 therefore serves as a descriptive system map rather than a country-severity classification. The background outage-hour bands are visual guides only and are not used as analytical thresholds, categories, or policy-priority boundaries. The country-level inputs underlying the figure are reported in Supplementary Table S1.

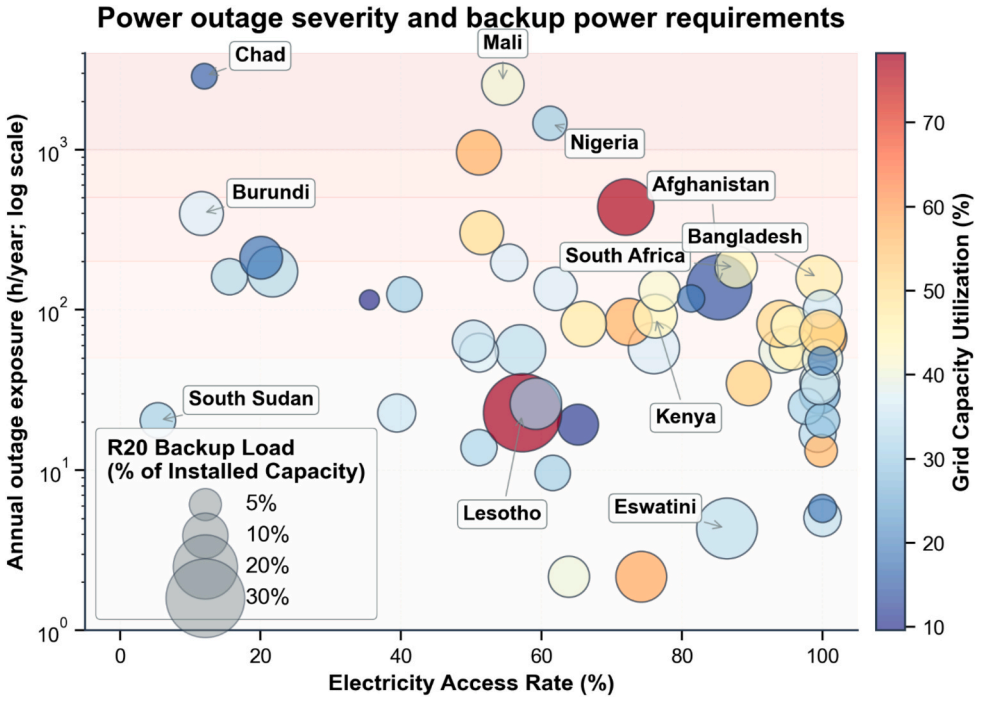


Fig. 2. Power outage severity and backup-power requirements across 56 outage-affected countries. Electricity access rate is shown on the x-axis and annual outage hours on the logarithmic y-axis. Bubble size represents the typical R20 retained backup load as a percentage of installed generation capacity and is used only as a visualization metric, while color indicates grid-capacity utilization. R20 denotes the reference modeling scenario. The pale outage-hour bands are visual guides and do not define analytical severity classes.

Sensitivity and structural robustness

Fig. 3 distinguishes sensitivity to explicit modeling assumptions from robustness to structural evidence choices. Panels (a) and (b) use the same matched 26-country sample so that the economic and climate responses are directly comparable. At the reference setting of R20 and $\eta = 35\%$, the net avoidable operating-energy cost is bounded by the admissible tariff branches at approximately USD 306.9–484.4 million/year, while the corresponding net additional climate burden under the standardized US GREET upstream pathway is approximately 0.915 $MtCO_2e$/year. These climate values are reported for the matched comparison subset only and do not replace the primary 56-country climate results.

Retained demand produces a monotonic and directly proportional response because the retention factor enters the backup-electricity requirement once. Moving from R05 to R40 therefore increases backup electricity and propagates proportionally into both the economic and climate burdens. In panel (a), the two economic bounds move together because each retention setting is evaluated across the same admissible tariff evidence; the shaded region is consequently an evidence-constrained tariff-branch envelope rather than a statistical confidence band. Panel (b) shows the same scale response for climate burden under the fixed US upstream pathway.

Generator efficiency operates through a different mechanism. Changing efficiency does not alter the backup-electricity requirement or the corresponding grid counterfactual; instead, it changes the diesel quantity required to supply each unit of backup electricity. Higher efficiency therefore reduces both diesel fuel operating cost and diesel fuel-cycle GHG intensity. The response is nonlinear because diesel consumption varies inversely with generator efficiency. This distinction explains why retained demand changes the physical scale of both outcome pathways, whereas efficiency modifies only the diesel side of the comparison after the backup requirement has been established.

Panels (c) and (d) isolate structural evidence choices at the reference

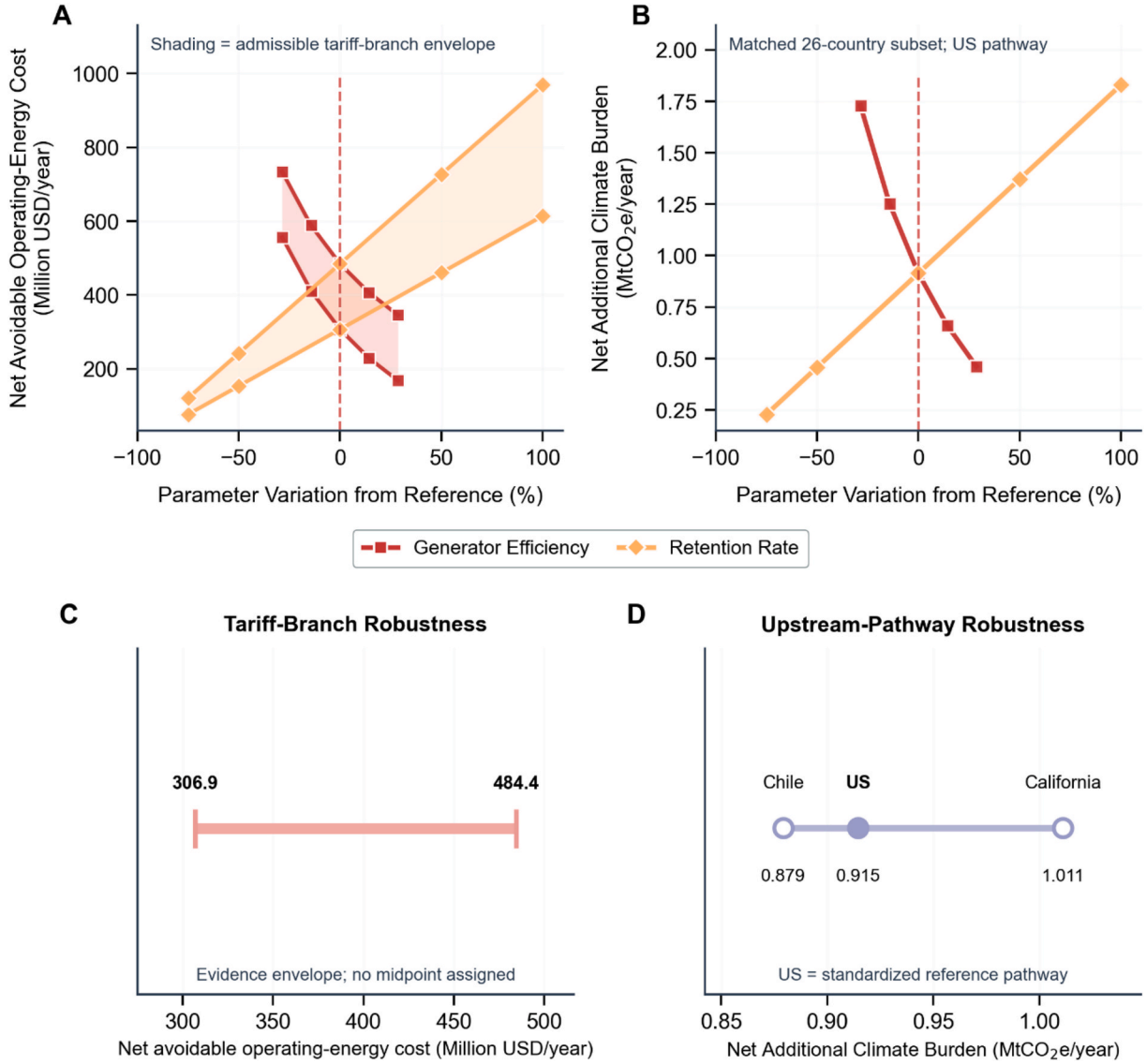


Fig. 3. Sensitivity and structural robustness of the economic and climate estimates. (a) Net avoidable operating-energy cost for the matched 26-country sample under changes in retained demand and generator efficiency. Shading denotes the admissible tariff-branch envelope; no midpoint or branch probability is assigned. (b) Net additional climate burden for the same matched 26-country sample under the standardized US GREET upstream pathway. (c) Economic structural robustness at R20 and $\eta = 35\%$, showing the admissible tariff-branch range for net avoidable operating-energy cost. (d) Climate structural robustness at R20 and $\eta = 35\%$, showing net additional climate burden under the Chile, US, and California upstream diesel pathways. The US pathway is used as the standardized reference rather than as a global-average upstream factor. Climate values in this figure refer to the matched 26-country comparison subset and do not replace the primary 56-country climate results.

R20 and η = 35% setting. The economic result remains an admissible tariff-branch range of USD 306.9–484.4 million/year, with no midpoint or branch probability assigned. For the climate calculation, changing only the upstream diesel pathway shifts the matched-sample net additional climate burden from approximately 0.879 $MtCO_2e$ under the Chile pathway to 1.011 $MtCO_2e$ under the California pathway, with the standardized US reference at 0.915 $MtCO_2e$. The climate burden remains positive under all three pathways.

Fig. 3 separates model sensitivities from structural evidence cases; exact values are reported in Supplementary Table S11, and none represents the empirical P05–P95 variation in Section 3.3. A supplementary O&M sensitivity raises the matched-26 net cost from USD 306.9–484.4 million/year to USD 372.6–550.1 million/year at USD 0.03/kWh and USD 438.3–615.9 million/year at USD 0.06/kWh; Senegal becomes positive at USD 0.03/kWh, while Solomon Islands remains negative at USD 0.06/kWh (Supplementary Table S12).

Country-level heterogeneity and uncertainty

Fig. 4 resolves the aggregate results into country-level physical, economic, and climate outcomes under R20, while preserving the different evidence boundaries of the analysis. Panel (a) contains the 26 countries with complete matched economic evidence, whereas panels (b)–(d) retain the full 56-country physical and climate sample. The matched economic countries account for approximately 2.190 TWh/year of expected R20 backup electricity, equivalent to 51.2% of the full-sample expected requirement.

Panel (a) shows substantial heterogeneity in both the magnitude and sign of the net avoidable operating-energy cost. Nigeria has the largest aggregate economic burden within the matched sample, reflecting the combination of a large backup-electricity requirement and positive unit operating-cost differences. Most countries remain positive across their admissible tariff branches, indicating that diesel fuel operating cost exceeds the matched grid variable cost within the defined accounting boundary. Two cases differ structurally: Solomon Islands remains

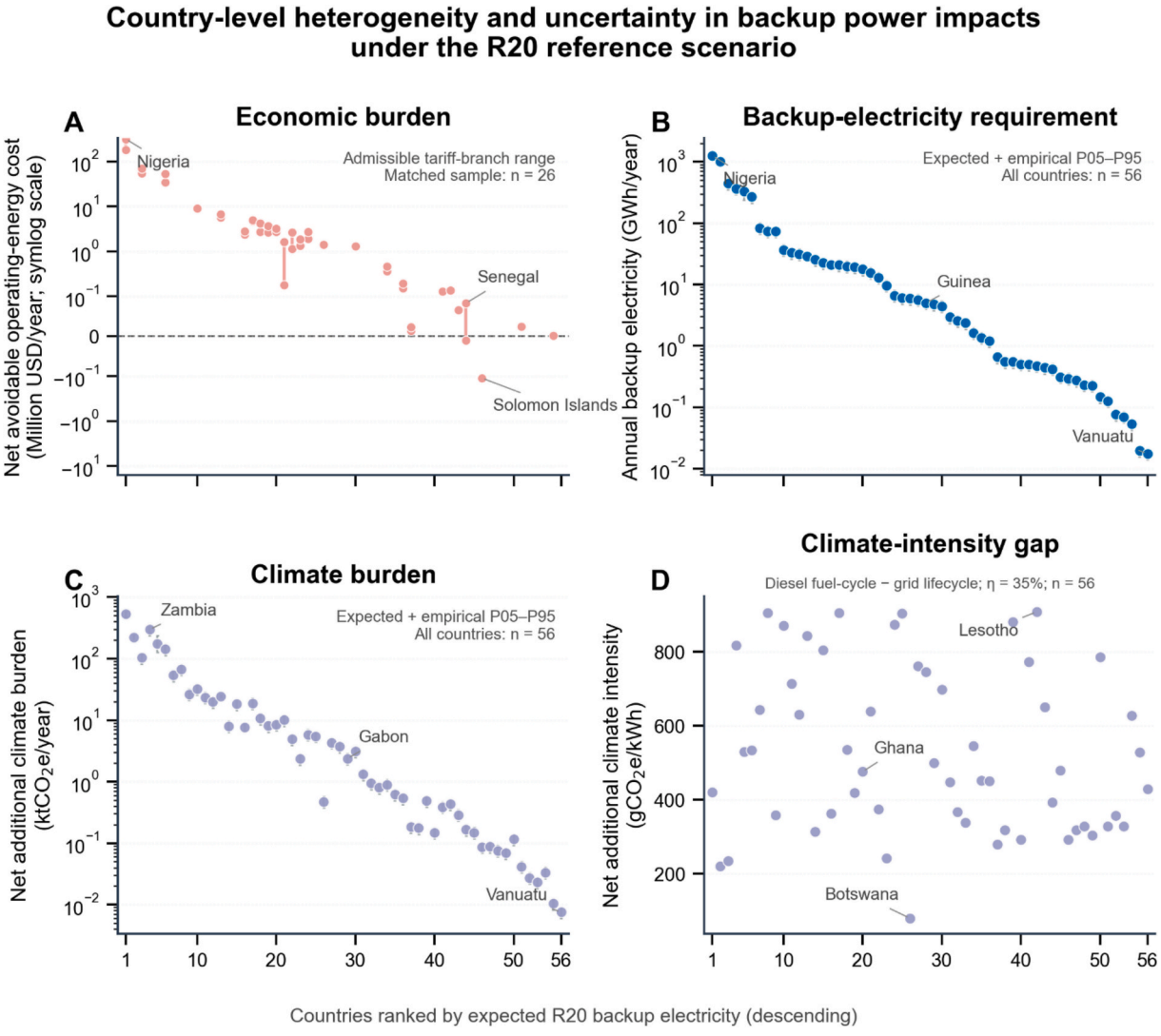


Fig. 4. Country-level heterogeneity and uncertainty in backup-power impacts under the R20 reference scenario. (a) Net avoidable operating-energy cost for the 26 countries with complete matched economic evidence; vertical ranges represent admissible tariff branches rather than confidence intervals. (b) Expected annual backup electricity and empirical P05–P95 ranges across all 56 countries. (c) Expected net additional climate burden and corresponding empirical P05–P95 ranges across all 56 countries. (d) Diesel fuel-cycle–grid lifecycle climate-intensity difference at η = 35% across all 56 countries. Countries are ordered by descending expected R20 backup electricity; panel (a) retains the matched economic subset in the same ordering. Empirical P05–P95 ranges reflect seasonal demand variation conditional on R20 and are not Monte Carlo confidence intervals. For the 50 transferred countries, the shared pooled support yields identical relative dispersion by construction.

negative across all admissible branches, whereas Senegal spans zero, so its economic sign depends on the applicable tariff branch. The vertical ranges represent structural tariff evidence rather than statistical confidence intervals.

Panel (b) shows that expected R20 backup-electricity requirements span several orders of magnitude across 56 countries. Nigeria contributes approximately 1.254 TWh/year, South Africa approximately 1.012 TWh/year, and Bangladesh approximately 0.443 TWh/year, whereas the smallest systems contribute only a small fraction of a GWh. The empirical P05–P95 ranges describe seasonal variation conditional on fixed R20 and are not alternative retention levels or confidence intervals. The six observed countries retain country-specific support; the other 50 share the pooled 72-factor support, so their relative P05–P95 structure and RIQR are identical by construction and only absolute widths scale with backup electricity. Relative dispersion therefore differs meaningfully only among the observed profiles; for example, Pakistan is wider than Nigeria or South Africa.

Panel (c) shows the corresponding distribution of expected net additional climate burden. Across all 56 countries, supplying the R20 backup requirement with the standardized diesel benchmark produces approximately 3.971 $MtCO_2e$/year of diesel fuel-cycle emissions, compared with approximately 2.123 $MtCO_2e$/year for the matched grid lifecycle counterfactual, yielding a net additional burden of approximately 1.849 $MtCO_2e$/year. Aggregate country burdens generally increase with backup-electricity requirement, but the relationship is not strictly proportional because each country is compared with a different

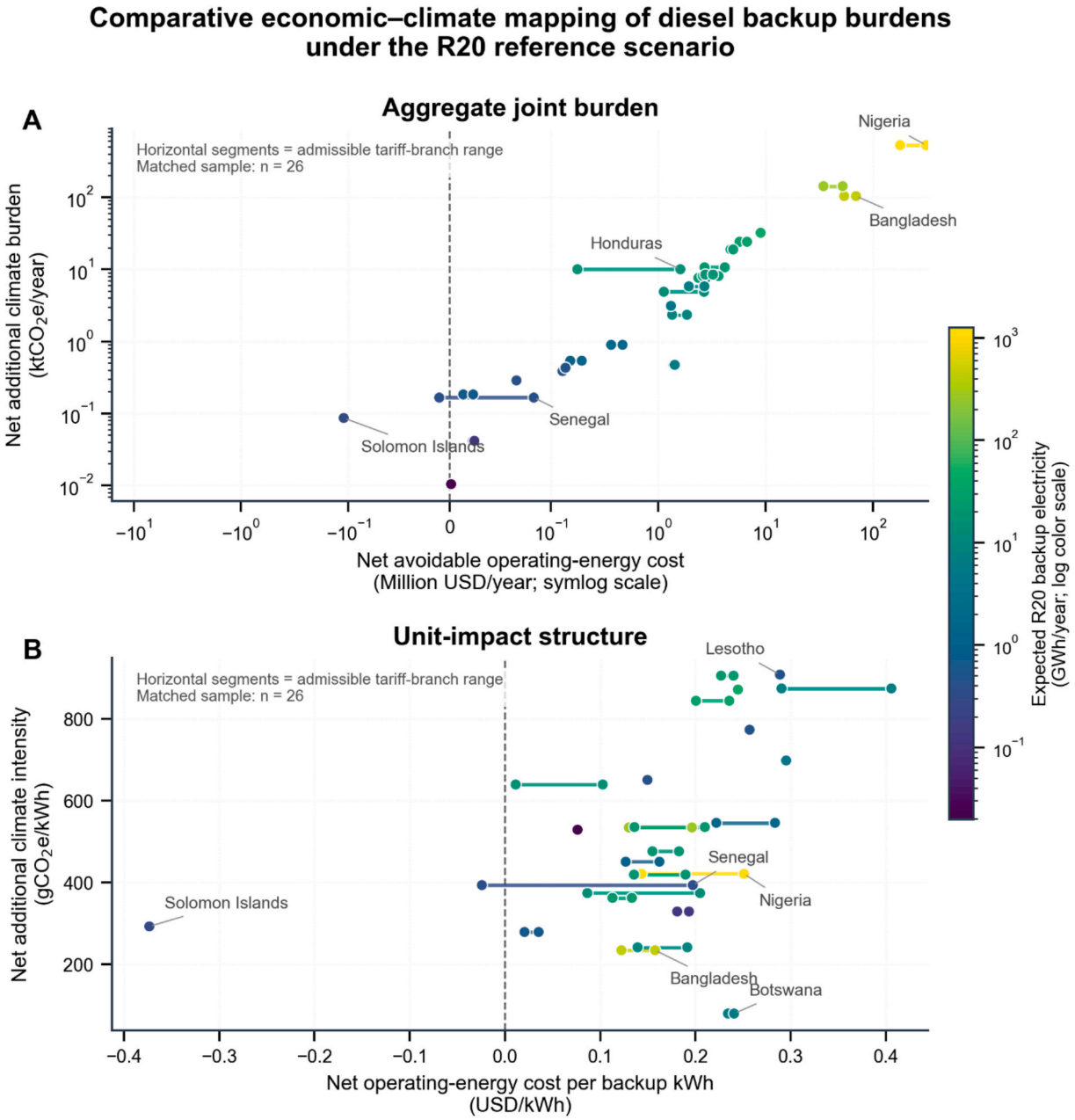


Fig. 5. Comparative economic–climate mapping of diesel backup burdens under the R20 reference scenario for the matched 26-country sample. (a) Aggregate net avoidable operating-energy cost versus expected net additional climate burden. (b) Net operating-energy cost per unit of backup electricity versus the diesel fuel-cycle–grid lifecycle climate-intensity difference. Horizontal segments denote admissible tariff-branch ranges without an assigned midpoint or probability, while color represents expected R20 backup electricity on a logarithmic scale. Panel (a) retains aggregate annual outcomes, whereas panel (b) expresses the economic and climate comparison per unit of backup electricity. The mapping uses direct physical and economic quantities and does not apply normalized scores, composite indices, severity classes, or policy-priority thresholds.

grid lifecycle intensity. Zambia provides a visible example of a comparatively high additional climate burden, whereas Gabon and Vanuatu illustrate progressively smaller aggregate burdens at lower backup-energy scales. Country-level P05–P95 ranges again reflect the propagation of empirical seasonal demand variation.

Panel (d) removes the annual backup-energy scale and compares the per-unit climate structure directly. At $\eta = 35\%$, the standardized diesel benchmark has a fuel-cycle intensity of approximately 929 gCO_2e/kWh, and the diesel fuel-cycle–grid lifecycle climate-intensity difference remains positive for all 56 countries. The wide cross-country spread is driven by differences in national grid lifecycle intensity rather than differences in the standardized diesel benchmark. The highlighted cases illustrate this contrast: Botswana has a comparatively small additional climate-intensity difference of approximately 79.6 gCO_2e/kWh because its grid counterfactual is relatively carbon intensive, whereas Lesotho is near the opposite end of the distribution at approximately 908.2 gCO_2e/kWh because its grid lifecycle intensity is very low. Ghana occupies an intermediate position. A small net difference should therefore be interpreted as similarity between diesel and the relevant grid counterfactual, not as evidence that diesel itself has low fuel-cycle emissions.

Taken together, Fig. 4 separates four dimensions that are easily conflated in aggregate statistics: economic sign and magnitude, physical backup-energy scale, empirical seasonal variability, and per-unit climate structure. The country-level values underlying panels (a)–(d) are reported in Supplementary Tables S7–S9.

Comparative economic–climate mapping

Fig. 5 synthesizes the matched 26-country sample by mapping the economic and climate outcomes simultaneously while retaining their original units. Panel (a) compares aggregate net avoidable operating-energy cost with expected annual net additional climate burden. Panel (b) expresses the same comparison on a per-unit basis using net operating-energy cost per backup kWh and the diesel fuel-cycle-grid lifecycle climate-intensity difference. In both panels, horizontal segments preserve the admissible tariff-branch range rather than assigning a midpoint, while color encodes expected R20 backup electricity on a logarithmic scale. The economic and climate source quantities underlying the mapping are reported in Supplementary Tables S8–S9.

Panel (a) demonstrates the importance of system scale in determining aggregate burden. Nigeria and Bangladesh occupy prominent upper-right positions because large expected backup-electricity requirements amplify both economic and climate consequences. The color gradient reinforces this relationship: countries with larger backup requirements generally contribute larger aggregate burdens even when their per-unit differences are not the most extreme. Conversely, smaller systems can remain close to the origin despite relatively unfavorable unit-level economic or climate characteristics. Aggregate burden should therefore be interpreted as the combined outcome of backup-energy volume and per-unit impact rather than as a direct measure of unit-level disadvantage.

The horizontal segments add a distinct economic-evidence dimension. Their lengths reflect the range generated by admissible grid-tariff branches and are not statistical error bars. Honduras provides a conspicuous example: its aggregate net-cost result spans approximately USD 0.177–1.610 million across the admissible tariff branches, producing a visibly broad horizontal range despite a moderate aggregate climate burden. The width of a segment therefore indicates structural sensitivity to tariff evidence, whereas its horizontal position indicates the level and sign of the resulting economic comparison.

The zero-cost axis further distinguishes the sign structure of the matched economic results. Most countries remain on the positive side, indicating higher diesel fuel operating cost than matched grid variable cost across their admissible branches. Solomon Islands lies entirely on the negative side, whereas Senegal spans zero and therefore changes sign depending on the applicable tariff branch. These patterns describe the matched operating-energy comparison only; the mapping does not identify whether the underlying country-specific structure arises from electricity tariffs, fuel pricing, taxation, subsidy arrangements, or other market conditions.

Panel (b) removes the direct effect of backup-electricity volume from both plotted axes and therefore exposes the underlying unit-impact structure. The substantial reordering relative to panel (a) shows that aggregate burden and per-unit disadvantage are not interchangeable. Lesotho exhibits one of the largest diesel fuel-cycle–grid lifecycle climate-intensity differences, whereas Botswana lies near the opposite end of the climate dimension because its grid counterfactual is comparatively carbon intensive. Nigeria and Bangladesh, despite their prominence in the aggregate view, occupy less extreme positions once economic and climate impacts are expressed per unit of backup electricity. The color scale remains useful in this panel because it reveals which unit-impact structures are applied over large versus small backup-energy volumes.

Fig. 5 therefore provides two complementary interpretations of the same matched sample: panel (a) identifies where total economic and climate burdens accumulate, while panel (b) identifies whether those aggregate outcomes are primarily associated with system scale or with unfavorable per-unit economic and climate differences. No score normalization, composite weighting, severity classification, numerical priority threshold, or tariff-branch probability is introduced. The mapping is intended to distinguish burden structures rather than to produce an algorithmic ranking of countries or interventions.

Discussion

Structural drivers of outage-driven backup burden under the diesel benchmark

The results indicate that the burden associated with the standardized diesel benchmark should not be interpreted simply as a direct consequence of poor reliability. Rather, its physical, economic, and climate dimensions reflect the interaction among outage exposure, the share of demand maintained during interruptions, electricity-system scale, and country-specific price and grid-climate conditions. In this sense, the resulting benchmark burden is a structural outcome of how reliability constraints interact with economic and operational conditions across power systems.

The sensitivity analysis clarifies that these factors enter the framework through different mechanisms. Retained demand changes the physical quantity of backup electricity required and therefore propagates directly into both economic and climate outcomes. Generator efficiency acts downstream of that requirement: it changes the quantity of diesel required per delivered kWh but does not alter the amount of electricity assumed to remain active during an outage. Tariff branches modify the economic counterfactual without changing backup electricity, whereas alternative upstream diesel pathways modify the fuel-cycle climate result without changing the physical requirement. Empirical seasonal variation constitutes a further, distinct dimension because it changes the outage-period load conditional on a specified retention scenario. These sources should therefore not be collapsed into a single class of uncertainty or model sensitivity.

The country-level results reinforce this structural interpretation. Systems with limited electricity throughput may exhibit modest aggregate burdens even under unfavorable outage conditions, whereas larger systems can accumulate substantial backup requirements when the same reliability constraint operates over a larger load base. System scale therefore acts primarily as an amplifier rather than as the initiating source of backup demand. This helps explain why countries with broadly similar outage conditions can exhibit sharply different aggregate outcomes and why outage exposure alone is insufficient for interpreting the consequences of backup dependence.

The economic results add a further structural layer. For most

countries in the matched sample, diesel fuel operating cost exceeds the matched variable grid cost of supplying the same electricity, but this relationship is not universal. Solomon Islands remains negative across all admissible tariff branches, whereas Senegal changes sign depending on the applicable branch. Moreover, the different widths of the country-level tariff ranges show that the evidence structure itself is heterogeneous: in cases such as Honduras, the admissible tariff branch materially changes the magnitude of the economic comparison even without reversing its sign. A positive or negative net avoidable operating-energy cost should therefore be interpreted only within the defined operating-energy boundary and should not be treated as evidence of lifecycle economic superiority of either diesel or grid supply.

These findings are consistent with, but extend, earlier evidence on self-generation and backup power. Steinbuks and Foster [36], using 8,483 firms in 25 African countries, found substantially higher in-house generation costs than purchased grid electricity; Cole et al. [37] showed that outages reduced firm sales more strongly where firms lacked generators, and more recent evidence indicates that self-generation can partially protect manufacturing activity [38]. At the broader systems level, Farquharson et al. [17] quantified higher backup-diesel costs and emissions across sub-Saharan Africa, while the IFC [18] modeled the large generator-service footprint across developing countries. Relative to these closest multi-country precedents, the present contribution is the harmonized linkage from reported outage exposure and system scale to explicit retention and seasonal-support assumptions, matched tariff branches, and country-specific grid-lifecycle counterfactuals.

Decoupling of aggregate burden and unit-impact structure

A central finding of this study is that aggregate burden and unit-impact structure are related but non-equivalent dimensions of outage-driven backup burden. Aggregate economic and climate outcomes reflect the consequences of supplying the total backup-electricity requirement and therefore depend strongly on system scale. Unit-level indicators instead describe the economic or climate difference associated with each unit of backup electricity. A country can consequently exhibit a high aggregate burden without having the most unfavorable per-kWh impact, while a smaller system can exhibit a pronounced unit-level disadvantage but contribute only modestly to the aggregate total.

The comparative mapping makes this distinction explicit. Nigeria and Bangladesh occupy prominent positions in the aggregate view largely because large expected backup-electricity requirements amplify the consequences of their unit-level differences. Once both axes are expressed per unit of backup electricity, their positions become less exceptional. Conversely, Lesotho exhibits one of the largest diesel fuel-cycle–grid lifecycle climate-intensity differences despite its small aggregate contribution, whereas Botswana lies near the opposite end of the climate-intensity distribution because its grid counterfactual is itself relatively carbon intensive. A small net climate-intensity difference therefore indicates similarity between diesel and the relevant grid counterfactual rather than intrinsically low-emission diesel generation.

This distinction also helps interpret the climate results more generally. The standardized diesel fuel-cycle intensity is held constant across countries at the reference efficiency, whereas the grid lifecycle intensity varies substantially. The positive diesel fuel-cycle–grid lifecycle difference across all 56 countries therefore does not imply a uniform climate penalty. Instead, the magnitude of the additional burden depends jointly on the country-specific grid counterfactual and the volume of backup electricity to which that per-unit difference is applied. Aggregate and unit-level climate outcomes can consequently rank countries differently.

The economic and climate dimensions can also diverge because their counterfactuals are structurally different. The economic comparison depends on diesel fuel cost relative to matched grid variable cost, while the climate comparison depends on diesel fuel-cycle GHG intensity relative to national grid lifecycle intensity. A country may therefore occupy an unfavorable position in one dimension without being equally unfavorable in the other. This is a property of the two comparisons rather than an inconsistency in the results.

For this reason, the framework does not combine economic and climate outcomes into a single composite score. Both dimensions are retained in their original monetary and physical units, while system scale is shown explicitly through backup-electricity volume. This allows the comparative mapping to distinguish volume-driven aggregate burden from unfavorable per-unit structure without introducing arbitrary weights, normalized severity indices, or numerical intervention thresholds.

The climate findings also extend earlier work on the environmental consequences of outage-related backup generation. Zhang et al. [4], in a China-focused assessment, showed that diesel-dominated backup generation can impose substantial environmental costs and emphasized the importance of power-system reliability in shaping those impacts. The present results are directionally consistent with that evidence but use a different analytical boundary: rather than estimating realized backup-generator deployment within one national system, the current framework applies a standardized diesel fuel-cycle benchmark to harmonized backup-electricity requirements across 56 countries and compares it with country-specific grid lifecycle counterfactuals. This cross-country structure reveals an additional source of heterogeneity that is less visible in a single-country assessment: even under a common diesel benchmark, the net climate penalty varies markedly with the carbon intensity of the displaced grid electricity and with the scale of the outage-driven backup requirement.

Interpretation of uncertainty and cross-country comparability

Another important contribution of the analysis lies in the explicit separation of different sources of variation. Country-level P05–P95 ranges describe empirical seasonal variation in backup-electricity requirements conditional on a specified retained-demand scenario. The six reference countries use their own observed monthly-factor support, whereas the remaining 50 countries use the pooled 72-factor reference support. These ranges are weighted empirical percentiles rather than confidence intervals and do not incorporate uncertainty in tariffs, generator performance, fuel supply, grid carbon intensity, or survey-based outage variables. Because cross-country dependence among seasonal and outage realizations is not identified, country-level percentiles are not aggregated into a global P05–P95 range.

Retained demand and generator efficiency are instead evaluated as explicit scenario and sensitivity dimensions. Admissible tariff branches and the Chile, US, and California GREET upstream pathways represent structural evidence choices rather than probabilistic uncertainty. The tariff range is retained without an assigned midpoint or probability, and the US upstream pathway is treated as a standardized reference rather than a global-average factor. Maintaining these distinctions avoids collapsing empirical variation, modeling assumptions, and evidence limitations into a single omnibus uncertainty measure.

This separation is especially important for cross-country comparison because the underlying evidence is temporally and methodologically heterogeneous. WBES outage observations span 2006–2024 and reflect firms' reported experience of typical outages rather than synchronized metered interruption records. The survey-year diagnostic shows no strong monotonic relationship between survey year and either annual outage exposure or expected R20 backup electricity, but it does not establish temporal equivalence among countries. Original survey years are therefore retained, and temporal asynchrony remains an explicit limitation rather than being treated as statistically corrected.

The partial comparison with WBES generator ownership provides an additional but deliberately limited consistency check. Generator ownership is positively associated with modeled R20 backup reliance, but both indicators originate from the same survey waves and generator ownership does not directly measure generator-supplied electricity. Moreover, under fixed R20 and an expected seasonal factor of one, the

validation quantity has the same cross-country rank ordering as annual outage hours. The association therefore supports directional consistency between outage exposure and generator adoption, but it does not validate absolute backup-electricity magnitudes, retained-demand levels, or the seasonal-demand transfer.

Implications for resilience planning and backup transition

The heterogeneity identified in this study has implications for resilience planning, but the results should not be interpreted as implying that diesel backup provides no operational value. Existing firm-level research shows that self-generation can reduce the production consequences of unreliable grid supply [37,38]. The benchmark quantified here instead isolates the operating-energy and climate consequences associated with supplying outage-driven backup requirements through diesel. The relevant planning problem is therefore not simply whether backup generation is costly or emissions intensive, but how continuity benefits, operating burden, reliability, and available alternatives should be balanced under local conditions.

In the near term, where diesel remains part of the continuity strategy, improvements in generator operating efficiency, critical-load management, preventive maintenance, and outage-response planning can reduce fuel consumption or improve effective delivery of essential electricity. Fuel-storage and resupply planning may also be important during prolonged interruptions, although these operational constraints are not explicitly modeled in the benchmark. Such measures can reduce the consequences of existing diesel reliance but do not eliminate the underlying exposure to grid interruptions.

The economic comparison further shows why country-specific price structures require careful interpretation. For most countries in the matched sample, diesel fuel operating cost exceeds matched grid variable cost, but Solomon Islands remains negative across admissible tariff branches and Senegal changes sign depending on the applicable branch. These cases warrant examination of the underlying market structure before policy conclusions are drawn. The harmonized evidence used here cannot identify whether a negative or cross-zero result is caused by grid tariffs, fuel-price regulation, taxation, subsidy arrangements, or another mechanism; it should therefore be treated as a signal for targeted investigation rather than automatic evidence for a particular reform. The O&M sensitivity further shows that Senegal's cross-zero result is not robust to a broader operating-cost boundary, whereas Solomon Islands remains negative throughout the tested USD 0.03–0.06/kWh range.

Over the longer term, reducing structural dependence on diesel backup requires improvements in grid reliability [39] and expansion of lower-emission forms of distributed resilience. Potential alternatives include battery storage, solar PV coupled with storage, PV–diesel and other hybrid systems, fuel-cell backup, and, where appropriate, gas-fired or CHP-based systems. Previous technology-specific studies have shown that such configurations can improve survivability or reduce cost and emissions under particular facility, load, and outage conditions [11–16]. Their suitability nevertheless depends on outage duration, load criticality, local renewable resources, capital cost, storage requirements, fuel infrastructure, and the carbon intensity of the relevant grid and fuels. The present diesel benchmark therefore provides a common reference point rather than a technology-ranking model.

Near- and long-term interventions address different parts of the burden. Operational measures act mainly on the diesel quantity required to supply a given backup load, whereas grid modernization, storage, distributed renewables, and alternative backup portfolios can reduce either the underlying need for diesel or the emissions associated with continuity provision. Electricity access alone is consequently not a sufficient indicator of resilience: systems with high nominal access may still incur substantial backup requirements when service interruptions persist. Reliability, continuity requirements, technology choice, and system scale should therefore be considered jointly.

Limitations and future research directions

Several limitations define interpretation and future extension of the framework. First, country-specific monthly demand profiles are available for only six reference countries. Leave-one-country-out validation showed that the pooled-median estimator outperformed the tested KNN alternatives, so the pooled estimator is used for countries without directly observed monthly profiles; nevertheless, the seasonal evidence base remains limited. The six reference countries retain their observed monthly factors, whereas the other 50 countries share a pooled empirical seasonal support. This treatment is transparent and reproducible but does not recover country-specific seasonal behavior where monthly observations are unavailable. Monthly-average factors also do not capture intraday peaks, short-duration load fluctuations, or exact coincidence between an outage and the load prevailing at that moment. Backup-electricity estimates should therefore be interpreted as harmonized annual and seasonal benchmarks rather than reconstructions of real-time outage operation.

Second, cross-country comparability is constrained by the temporal and reporting characteristics of the outage data. WBES observations span 2006–2024 and represent firms' reported experience of typical outage frequency and duration rather than synchronized metered interruption records. The survey-year diagnostic does not reveal a strong monotonic association with annual outage exposure or expected R20 backup electricity, but temporal asynchrony remains. Self-reported outage indicators may also be affected by recall error or omission of shorter or less disruptive interruptions. If such events are systematically underreported, modeled backup requirements and associated economic and climate burdens would tend to be underestimated, particularly among countries at the lower end of reported outage exposure. No ex-post correction factor is imposed because a harmonized country-specific underreporting rate cannot be identified from the available evidence.

Third, diesel generation is treated as a standardized benchmark for supplying the modeled backup-electricity requirement rather than as an assertion that all outage-related backup electricity in the 56 countries is actually supplied by diesel. Real continuity portfolios may include battery storage, solar PV–storage systems, PV–diesel hybrids, fuel cells, gas generators, CHP, or combinations of these technologies. Their costs, emissions, and operating constraints may differ substantially and evolve over time. The present results should therefore be interpreted as consequences of a diesel-supplied benchmark conditional on the modeled backup requirement, not as a forecast of the complete future backup-technology mix. Future work should extend the framework to technology-specific and hybrid configurations under common outage, tariff, and climate-accounting boundaries.

Fourth, the economic analysis has a deliberately restricted accounting and evidence boundary. Complete matched diesel-price, grid-tariff, and exchange-rate evidence is available for 26 countries, representing approximately 51.2% of expected R20 backup electricity in the full sample; economic conclusions should not be extrapolated mechanically to all 56 countries. Net avoidable operating-energy cost compares diesel fuel expenditure with the matched variable grid cost of the same delivered electricity and excludes generator capital expenditure, maintenance, replacement, financing, and broader social costs. Harmonized country-specific O&M evidence is unavailable, so O&M is not incorporated into the primary national estimates; instead, the literature-anchored USD 0.03–0.06/kWh sensitivity tests a plausible nonfuel O&M adder without treating it as country-specific. A negative net avoidable operating-energy cost indicates only that diesel fuel cost is lower than the matched grid variable cost within this boundary and does not establish lifecycle economic superiority.

Finally, the benchmark assumes that modeled retained electricity can be delivered whenever an outage occurs, conditional on generator operability and sufficient fuel availability. Start-up failure, mechanical unavailability, on-site storage limits, fuel-delivery disruption, and

resupply constraints could reduce realized diesel generation, fuel expenditure, and fuel-cycle emissions relative to the benchmark while simultaneously increasing unmet electricity demand and service disruption. No universal availability or fuel-resupply derating factor is imposed because a harmonized cross-country value is not supported by the available evidence. The climate boundary includes upstream diesel production and stationary combustion but excludes generator manufacturing, generator transport, infrastructure construction, and end-of-life; local air pollutants are also outside the primary climate framework. Future research could integrate technology availability, fuel logistics, maintenance, higher-frequency demand and outage data, fuller lifecycle assessment, and technology-specific backup portfolios under a common counterfactual framework, allowing diesel, storage, renewable hybrids, fuel cells, and other continuity options to be compared on consistent economic, climate, and reliability boundaries.

Conclusion

This study develops a harmonized cross-country framework for examining the economic and climate implications of outage-driven diesel backup power across 56 outage-affected countries. Under the R20 reference modeling scenario, the expected backup-electricity requirement is approximately 4.275 TWh/year. For the full 56-country climate assessment, supplying this requirement with the standardized diesel benchmark results in approximately 3.971 $MtCO_2e$/year of fuel-cycle emissions, compared with 2.123 $MtCO_2e$/year for the corresponding grid lifecycle counterfactual, yielding a net additional climate burden of 1.849 $MtCO_2e$/year. For the 26 countries with complete matched economic evidence, the corresponding net avoidable operating-energy cost is USD 306.9–484.4 million/year under the admissible tariff branches.

The results show that outage-driven backup burden is not determined by outage exposure alone. Retained demand governs the physical scale of backup electricity, system size amplifies aggregate consequences, generator efficiency affects downstream diesel use, and country-specific price and grid-emissions conditions shape the economic and climate comparison. Aggregate burden and per-unit impact structure can therefore diverge across countries. The analysis also demonstrates the importance of distinguishing empirical seasonal variation from model sensitivity and structural evidence ranges rather than collapsing these sources into a single uncertainty or composite vulnerability measure.

The framework should be interpreted as a standardized diesel benchmark rather than a representation of the complete backup-technology mix in each country. In the near term, improvements in operating efficiency, critical-load management, preventive maintenance, and fuel-logistics preparedness can improve the reliability and performance of existing diesel-based continuity arrangements, although these measures do not remove the underlying exposure to grid interruptions. Over the longer term, grid-reliability improvements, distributed storage, renewable-hybrid systems, and other lower-emission resilience technologies can reduce structural dependence on diesel backup. Future work should extend the framework using higher-frequency outage and demand data, technology-specific backup portfolios, generator availability and maintenance evidence, and broader lifecycle boundaries.

CRediT authorship contribution statement

Fangjie Liu: Writing – original draft, Visualization, Software, Resources, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Muhammad Shafique:** Writing – review & editing, Validation, Supervision, Project administration, Methodology, Formal analysis, Data curation, Conceptualization. **Yixuan Liu:** Visualization, Resources, Methodology, Formal analysis, Data curation. **Xiaowei Luo:** Writing – review & editing, Supervision, Resources, Project administration, Formal analysis, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.seta.2026.105497.

Data availability

Data will be made available on request.

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