

Increasing the resilience of the Texas power grid against extreme storms by hardening critical lines

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Supplementary Note 1

Hurricane data sets

Supplementary Table 1 lists some characteristics of the TCs considered in this study. In particular, it contains values of the power outages P_r^{out} that were reported for the TCs. Since most reports quantify the extent of power outages in terms of the number of customers N_r^{out} left without electricity, we converted these numbers to corresponding power outages P_r^{out} . These numbers can be directly compared to the power outages observed in our simulations.

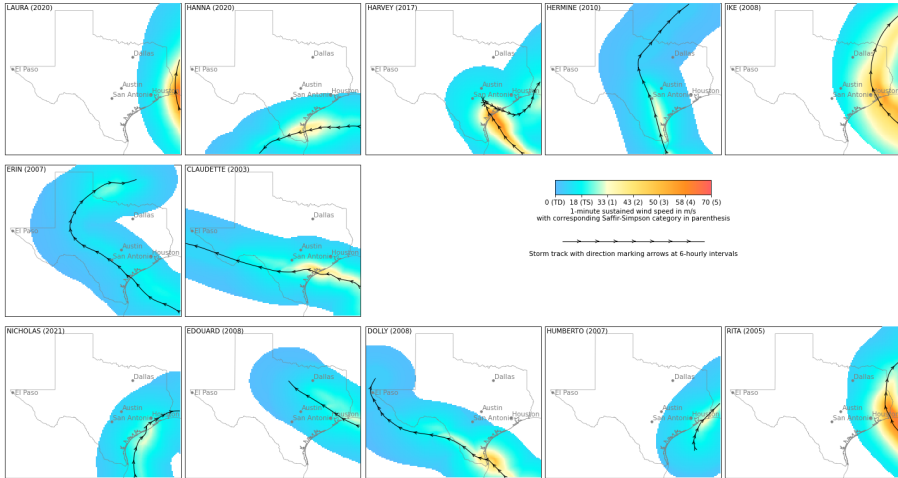
For this purpose, we assume that the reported customers represent residential customers (households) and therefore scale N_r^{out} with the average active power load $\bar{P}_h$ per household. The latter can be estimated as $\bar{P}_h \approx 2.85 \times 2\text{kW} = 5.7\text{kW}$, where the factor 2.85 represents the average number of persons per household in Texas according to the U.S. Census Bureau¹ and 2kW is the per capita active power load according to Birchfield et al.². We use this per capita load for consistency as it was also used in the construction of the considered synthetic power grid of Texas. Ultimately, we have

$$P_r^{\text{out}} \approx N_r^{\text{out}} \cdot \bar{P}_h \approx N_r^{\text{out}} \cdot 5.7\text{kW}. \quad (\text{S1})$$

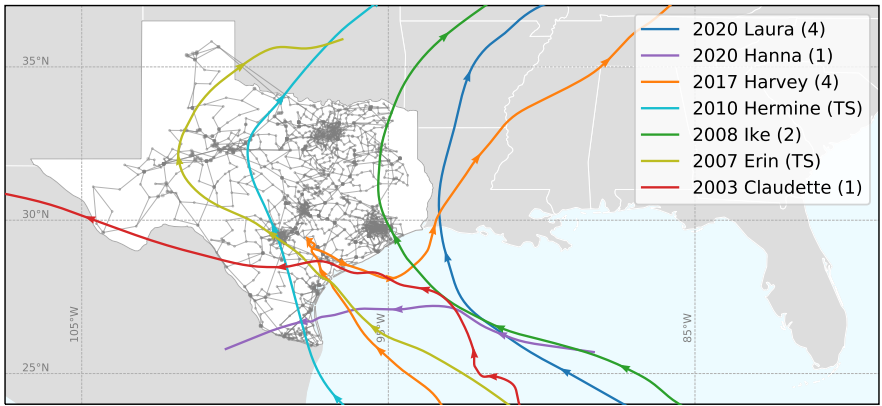
Supplementary Fig. 1 shows the intensities of the considered TCs in terms of the maximum 1-minute sustained wind speeds that along the tracks. It should be noted that the different types of wind speeds mentioned in this study can all be easily converted into each other using appropriate conversion factors. More specifically, we convert a 10-minute sustained wind speed into a 3-second gust wind speed using the conversion factor $K_v = 1.43$ (see also Supplementary Table 2). Likewise, one may transform a 10-minute sustained wind speed into a 1-minute sustained wind speed using the well-established factor of 0.88²².

Supplementary Table 1: Additional information on the considered TCs, whose trajectories are shown in Supplementary Fig. 1 and Supplementary Fig. 2. Date and category (Saffir-Simpson hurricane scale with “TS” standing for tropical storms) relate to the landfall of each TC. Parameters v_m and T denote the maximum 10-minute sustained wind speed and the total time span covered by the track data used in simulations. N_r^{out} represents the reported number of customers left without power during the respective TC, which is converted to a power outage P_r^{out} using Eq. (S1). Sources of all values are indicated respectively.

Name	Date (MM/DD/YY)	Category	v_m [m/s]	T [hh : mm]	N_r^{out} [10^6]	P_r^{out} [GW]
Laura	08/27/2020 ³	4 ³	55.65	62 : 15	0.139 ⁴	0.79
Hanna	07/25/2020 ⁵	1 ⁵	37.01	87 : 30	0.200 ⁵	1.14
Harvey	08/26/2017 ⁶	4 ⁶	51.05	188 : 35	1.670 ⁷	9.52
Hermine	09/07/2010 ⁸	TS ⁸	29.95	87 : 35	0.230 ⁹	1.31
Ike	09/13/2008 ¹⁰	2 ¹⁰	48.91	61 : 50	3.200 ⁷	18.24
Erin	08/16/2007 ¹¹	TS ¹¹	22.36	114 : 00	0.020 ¹²	0.11
Claudette	07/15/2003 ¹³	1 ¹³	40.07	123 : 15	0.074 ¹⁴	0.42
Rita	09/24/2005 ¹⁵	3 ¹⁵	49.07	192 : 00	0.700 ¹⁶	4
Humberto	09/13/2007 ¹⁷	1 ¹⁷	38.02	48 : 00	0.114 ¹⁸	0.8
Dolly	07/23/2008 ¹⁹	1 ¹⁹	40.01	168 : 00	0.212 ¹⁸	1.1
Edouard	08/5/2008 ²⁰	TS ²⁰	27.05	72 : 00	0.030 ¹⁸	0.3
Nicholas	09/14/2021 ²¹	1 ²¹	36.02	192 : 00	0.50 ²¹	2.9



Supplementary Figure 1: Maximum wind speeds attained in each grid cell during each storm’s life time according to the used parametric wind model.



Supplementary Figure 2: Historical hurricanes with different pathways and intensities passed through Texas in the last 18 years The topology of the Texan electric grid is overlaid with the storm tracks of the hurricanes considered in this study. The year, name, as well as the category at landfall according to the Saffir-Simpson hurricane scale are given in the figure legend (“TS” means tropical storm). For more detailed information on the hurricane selection and data see Supplementary Table 1.

Supplementary Note 2

Wind force equation

The full wind force equation according to the ASCE guidelines²³ reads

$$F^{\text{wind}}(l, z, v) = Qk_z I_{\text{FW}} G_{\text{WRF}}(l, z) C_{\text{fAC}} v^2, \quad (\text{S2})$$

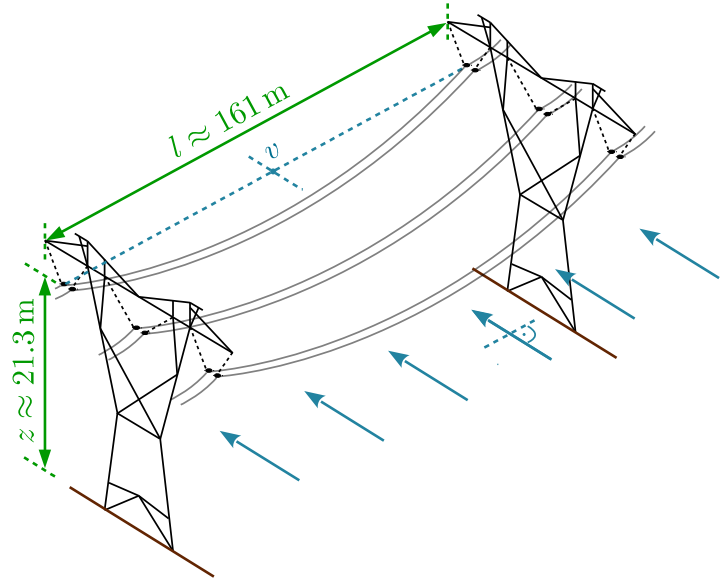
where v denotes the 3-second gust wind speed at height z and G_{WRF} is the so-called wind gust response factor defined as

$$G_{\text{WRF}}(l, z) = \frac{1}{k_v^2} [1 + 13.23 \sqrt{\kappa} (\frac{z_0}{z})^{1/\alpha} (1 + 0.8 l/L_s)^{-0.5}]. \quad (\text{S3})$$

The physical meaning of all parameters as well as their respective value used in our simulations are listed in Supplementary Table 2. Further details about the parameters can be found in the ASCE report²³.

To apply the wind force equation (S2) in our simulations via the failure probability in equation (2), we make the following assumptions: (i) We assume that the wind always acts perpendicular to the transmission lines, i.e., we neglect yawed winds (see Supplementary Fig. 3). This may lead to an overestimation of the wind force in some cases. (ii) All terrain is considered to belong to the “Exposure Category C” defined as “open terrain with scattered obstructions” in ref.²³. While this choice should be appropriate for most of Texas, it can lead to an overestimation of wind forces in urban regions and an underestimation in very flat areas. Nonetheless, ref.²³ recommends the use of Exposure Category C as long as other categories have not been carefully identified as being more appropriate. Likewise, topographic effects that may result from local terrain characteristics like mountains, hills and valleys are neglected. (iii) The sagging of conductor wires is neglected. (iv) We fix the value of the breaking force in equation (2) to $F^{\text{brk}} = 152.13 \text{ kN}$ which corresponds to the ultimate tensile strength of the “Cardinal” conductor²⁴. The latter belongs to the aluminium conductor steel-reinforced (ACSR) class and is mentioned by Gegner et al. in ref.²⁵ as an appropriate conductor type for overhead lines in synthetic power grids. The value of F^{brk} can be fixed without loss of generality since the line failure probabilities depend on the ratio $r^{\text{brk}}/F^{\text{brk}}$ and the collapse rate r^{brk} is treated as a free parameter (see Supplementary Note 5 for further details).

Using the wind force equation (S2) to define the failure probability of transmission lines is strongly motivated by the work of Winkler et al. in ref.²⁸.



Supplementary Figure 3: Schematic structure of an overhead transmission line segment. Important dimensions are highlighted green, namely the span length l , which is given by the distance between the towers, and the effective height z . Their values correspond to typical values given in refs.^{26,27}. The wind speed v is assigned to the line segment using the halfway point located between the towers at height z . The width of transmission towers relative to length l is here drawn in an exaggerated way and is actually not considered in our model.

Supplementary Table 2: Additional information on the parameters appearing in the wind force design equation (S2). The choices of the parameter values were made according to the explanations given in reference²³.

Parameter	Symbol	Value	Comment/Meaning
Air density parameter	Q	0.613 kg/m ³	Value recommended by ref. ²³
Terrain exposure coefficient	k_z	1.17	Value for open terrain with scattered obstructions
Importance factor	I_{FW}	1.00	Return period of 50 years
Wind gust response factor	G_{WRF}	Equation (S3)	Accounts for peak dynamic wind loads
Surface drag coefficient	κ	0.005	Value for open terrain with scattered obstructions
Height	z_0	10.06 m	The average height between the ground level and 10.06 m
Effective height	z	21.3 m	Height of wire attachment points (see Supplementary Fig. 3)
Power law exponent of sustained wind	α	7.0	Value for open terrain with scattered obstructions
Wind speed conversion factor	K_v	1.43	Ratio of 3-s gust wind speed to 10-min sustained wind speed
Line span length	l	161 m	Distance between towers (see Supplementary Fig. 3)
Turbulence scale	L_s	67.056 m	Value for open terrain with scattered obstructions
Force coefficient	C_f	0.9	Accounts for circular wire shape
Surface area normal to wind direction	A_C	$l \cdot 0.03$ m	Wire cross-section (0.03 m is the diameter of the “Cardinal” conductor ²⁴)

Supplementary Note 3

DC power flow model

For an electrical grid with N buses, the static AC power flow equations are an $2N$ nonlinear algebraic equation system, that is given by

$$P_i = \sum_{j=1}^N |V_i| |V_j| [G_{ij} \cos(\theta_i - \theta_j) + B_{ij} \sin(\theta_i - \theta_j)] , \quad (\text{S4})$$

$$Q_i = \sum_{j=1}^N |V_i| |V_j| [G_{ij} \sin(\theta_i - \theta_j) - B_{ij} \cos(\theta_i - \theta_j)] , \quad (\text{S5})$$

where P_i and Q_i are the net active and reactive power injections at bus i . $|V_i|$ and θ_i are the voltage amplitude and angle of the complex voltage. G_{ij} and B_{ij} are the conductance and susceptance matrix of the grid, which comprise its network structure as well as the static line parameters. The DC power flow model is a simplification of the AC power flow equations that is based on four additional assumptions: i) Ohmic losses originating from the resistances of lines and transformers are neglected, which leads to $G_{ij} = 0$ for all i, j . (ii) The voltage profile is assumed to be flat, meaning that we set the voltage magnitudes to $|V_i| = 1$ pu for all buses i . (iii) Reactive power flow is neglected. (iv) The voltage angle difference between connected buses is assumed to be small, such that $\sin(\theta_i - \theta_j) \approx \theta_i - \theta_j$. Applying these assumptions to (S4,S5) yields the DC power flow model

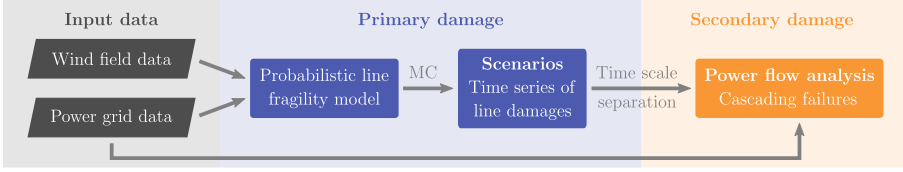
$$P_i = \sum_{j=1}^N B_{ij} (\theta_i - \theta_j) . \quad (\text{S6})$$

For a grid with N buses, this is a system of N linear algebraic equations. The main reason for using this model for calculating the power flows is that this is much easier to solve than the full nonlinear AC model which tends to run into numerical infeasibilities after the grid has been affected by a significant amount of line failures. The net active power injections P_i at the buses are given in the electrical test case. The DC power flow equations are solved for the voltage angles θ_i using the Julia package `PowerModels.jl`^{29,30} and the numerical solver `Ipopt`³¹. Once a line is damaged by the hurricane, it is deactivated in the test case which changes the susceptibility matrix B_{ij} and, thereby, the solution of the DC power flow model. The power flow on the individual lines is given by

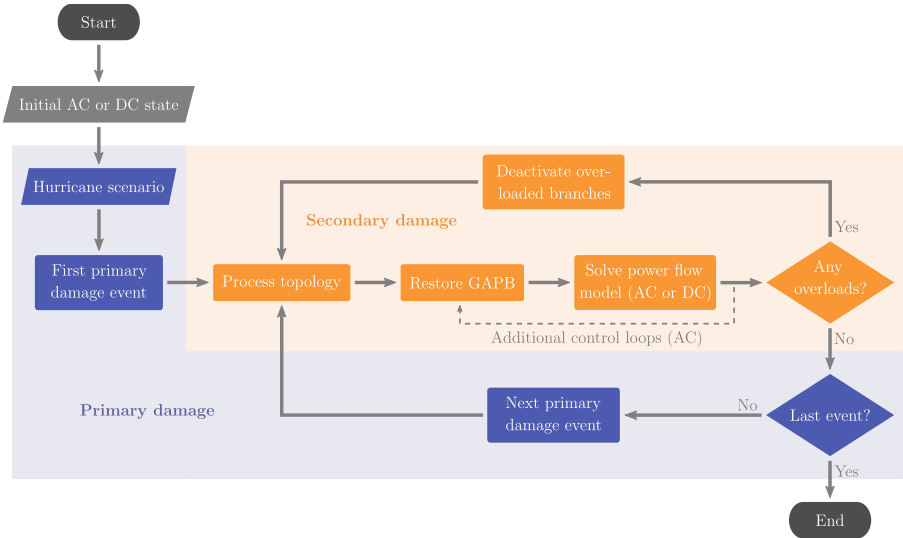
$$P_{ij} = B_{ij} (\theta_i - \theta_j) . \quad (\text{S7})$$

When the line flow exceeds the capacity given in the test case, it is deactivated. The process of recalculating the power flow and deactivating overloaded lines is repeated iteratively until no line in the grid is overloaded. An overview of the entire model for calculating the wind load on the transmission lines and,

then, applying PF-model to redistribute the power flow in the network after each damage is depicted in Supplementary Fig. 5 and 4.



Supplementary Figure 4: Flowchart describing the general workflow.



Supplementary Figure 5: Flowchart describing the simulation model.

Supplementary Note 4

Global active power balance (GAPB)

During cascades of line failures it is possible that single loads or generators are disconnected from the rest of the grid or that the grid is split into several components. This will usually result in a power mismatch between active power generation $P_{G[n]}$ and demand $P_{L[n]}$ in each component n

$$\Delta P^{[n]} = P_{G[n]} + P_{L[n]} . \quad (\text{S8})$$

Such a power mismatch will cause an acceleration or deceleration of the generating units within a component and lead to a frequency deviation $\Delta\omega^{[n]}$. On

the considered timescale of seconds, the size of this deviation is determined by the primary frequency control (PFC). This decentralized control scheme adjusts the power of each generator k proportionally to the frequency deviation $\Delta P_k^g = -D_k \cdot \Delta\omega$ until power balance is regained.

$$\sum_{k \in \mathcal{G}^{[n]}} \Delta P_k^g + \Delta P^{[n]} = 0. \quad (\text{S9})$$

From this it follows that the power adjustments of the generators are given by

$$\Delta P_k^g = -\frac{D_k}{\sum_{k \in \mathcal{G}^{[n]}} D_k} \Delta P^{[n]}. \quad (\text{S10})$$

Since the control parameters D_k are not included in the data set of the electrical grid, we assume that they are uniform, i.e. $D_k = D$ for all $k \in \mathcal{G}^{[n]}$. Eq. (S10) then reduces to

$$\Delta P_k^g = -\frac{\Delta P^{[n]}}{|\mathcal{G}^{[n]}|}, \quad (\text{S11})$$

where $|\mathcal{G}^{[n]}|$ denotes the number of generators in the respective component. Hence, we increase the active power dispatches uniformly in the case of a deficiency in generation ($\Delta P^{[n]} < 0$) and decrease them uniformly in the case of an overproduction of active power ($\Delta P^{[n]} > 0$). In practice, however, we have to respect the upper and lower bounds P_k^{gu} and P_k^{gl} of generators, which are provided in the power grid data set. For this purpose, the adjustment of generator dispatches is done iteratively using the respective set $\mathcal{G}_-^{[n]}$ of generators in $\mathcal{P}^{[n]}$ that are able to reduce their dispatches in the case of overproduction or the respective set $\mathcal{G}_+^{[n]}$ of generators in $\mathcal{P}^{[n]}$ that are able to increase their dispatches in the case of underproduction. Nevertheless, there exist two cases that require special treatment: (i) It may happen that setting all generator dispatches to their respective lower bound still results in an overproduction in the respective component. In that case, primary frequency control (PFC) cannot prevent a steadily increasing grid frequency and the considered power grid would sooner or later experience a blackout. Hence, we assume in our simulations that this component fails entirely due to “unavoidable overproduction”. (ii) On the other hand, it may happen that setting all generators to their respective upper bound still results in an underproduction in the respective component. In that case, the active power demand of loads is shed uniformly in a way that is analogous to the adjusting of generator dispatches. Any load shedding that occurs also contributes to the overall power outage at the end of the hurricane phase. An overview of the entire model for restoring the power balance in the grid components is depicted in Supplementary Fig. 6.



Supplementary Figure 6: The flowchart describing the applied algorithm to restore Global active power balance (GAPB) based on primary frequency control (PFC).

Supplementary Note 5

Model calibration

Our transmission line fragility model contains a collapse rate parameter r^{brk} that can be used to tune the model such that the simulation results for past hurricanes agree with historically reported damages and power outages. The scaling of the average number of wind-induced line failures scales with the collapse rate has been derived in Supplementary Note 8. However, to the best of our knowledge, there is no reliable public database containing the exact number of wind-induced line failures for past hurricanes. Instead, we can only calibrate our model by comparing the obtained power outage distributions with historical outage data. For this purpose, we have searched the official tropical cyclones reports published by the National Hurricane Center³², the major event analysis reports published by the North American Reliability Corporation³³, the event analysis reports of the Texas Reliability Entity³⁴, as well as newspaper articles for information on the extent of power outages. Since most sources report power outages in terms of the number of customers N_r^{out} left without electricity, we have to convert this number to a corresponding power outage P_r^{out} , following Eq. S1, which we can compare with our simulation results. The used values of N_r^{out} and P_r^{out} as well as the corresponding sources are listed in Supplementary Table 1. Furthermore, the values of P_r^{out} are indicated in Supplementary Fig. 7 as dashed vertical lines. Requiring that the reported values have a nonzero probability in our simulations, i.e., the vertical lines cross the respective power outage distributions in Supplementary Fig. 7, allows us to restrict the collapse rate r^{brk} to values that satisfy

$$10^{-4} \text{ h}^{-1} < r^{\text{brk}} < 5 \times 10^{-3} \text{ h}^{-1}. \quad (\text{S12})$$

Here, the lower bound can be motivated by the fact that the reported outages for Hurricane Harvey, Ike and Hermine are not captured by the respective power outage distribution (see Supplementary Fig. 7a, 7b and 7f). Analogously, the upper bound can be justified by the power outage reported for Hurricane Harvey not being reproduced (see Supplementary Fig. 7a). For the simulations in the main part of the paper we used a fixed value of $r^{\text{brk}} = 0.002 \text{ h}^{-1}$. In order to check the robustness of these results, we repeated the Monte Carlo simulations with randomized collapse rates for every transmission line and every TC scenario. For this, the individual collapse rates r^{brk} were drawn uniformly from the interval $[0.0001 \text{ h}^{-1}, 0.005 \text{ h}^{-1}]$ that we have identified as being consistent with the reported outages. Supplementary Fig. 8 shows a comparison of the power outage distributions for the simulations with fixed and randomized collapse rate r^{brk} . Remarkably, the outage distributions do not only show the same shape but are also qualitatively very similar. The peaks of the multimodal distributions are at the same positions, there are only slight changes in the probability density of those peaks for some of the hurricanes.

We can therefore conclude that our results are in fact quite robust towards variations of the collapse rate parameter r^{brk} .

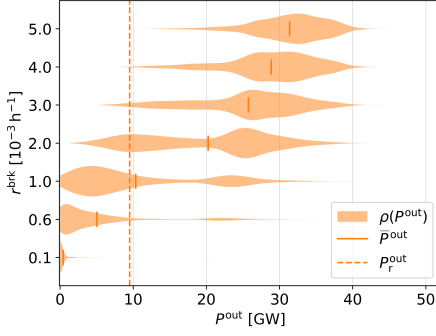
In Supplementary Fig. 9 similar to Fig. 4 in the main text, three different sections of the respective power outage distribution for hurricanes Ike, Erin, Hermine and Laura are shown. These results are belong to $r^{\text{brk}} = 0.002 \text{ h}^{-1}$, and the insets in each figure show the respective power outage distribution. The exact range of considered power outages are displayed below these insets. Dashed vertical lines in insets represent the reported power outages (see Supplementary Table 1). As seen in Supplementary Fig. 9a, 9d, 9g and 9j in the smallest outages, damages remain mainly localized at the storm tracks. In all hurricanes, regardless of their intensities and path, the city of Houston can be disconnected from the network and face blackout (see Supplementary Fig. 9b, 9f, 9i and 9l). Non-local effect of cascading failures is shown in Supplementary Fig. 9a and 9h. Although the western region $\mathcal{W}$ is not reached by Ike and Hermine, it exhibits an increased outage probability.

Simulations of weaker hurricanes

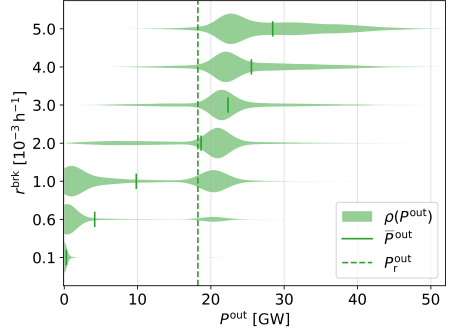
To demonstrate the validity of our model as well as the calibration, we repeat our simulations for five additional hurricanes: Rita, Humberto, Dolly, Edouard and Nicholas. As seen in Supplementary Fig. 1, these storms primarily affect coastal areas. Therefore, based on their movement path, they are not expected to significantly impact the transmission grid. This is supported by the very small mean number of damaged lines and power outages as the results of our simulations and shown in Fig. 10. The published reports on the damages caused by Hurricanes Nicholas, Dolly, and Edouard explicitly state that the distribution grid was significantly impacted during these hurricanes, providing evidence to support our claim^{19–21}. We speculate that during Hurricane Rita and Humberto mainly the distribution grid has been damaged, however there is no detailed information about the exact damaged transmission and distribution lines in the reports.

Nonlocal spreading of cascading failures

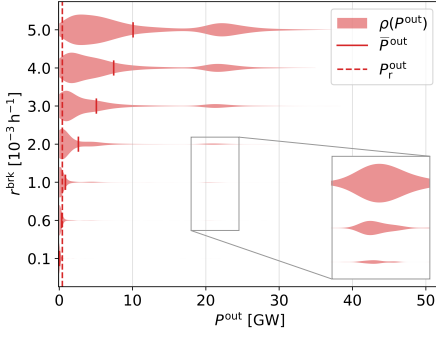
To clarify the nonlocal effect of cascading failures, here we demonstrate an exemplary cascading failure that can be triggered in the eastern part of the power grid and which also affects the western region. More specifically, the cascade can be induced in the initial DC state of the power grid by tripping two lines which are labeled with indices “1503” and “1597” in the data set. The lines are highlighted in Supplementary Fig. 11a and are located in the southeastern region between the large cities Houston, Austin, San Antonio and Corpus Christi. Most importantly, however, they transport power from a cluster of generators (encircled by the black dashed ellipse) to the central cities San Antonio and Austin. The direction of the power flow can be identified from the direction of the arrows shown in the inset in Supplementary Fig. 11a. Based on the outage probability plots shown in Fig. 4 and Supplementary Fig. 9, one could expect a correlation between the outage of this cluster and the outages



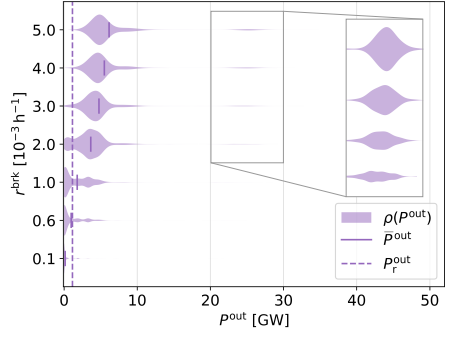
(a) Hurricane Harvey



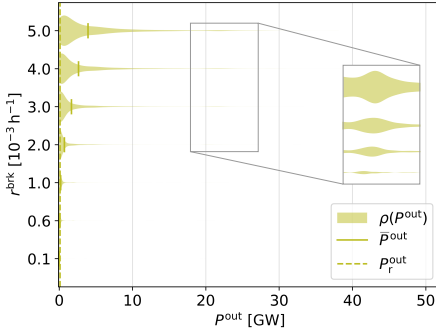
(b) Hurricane Ike



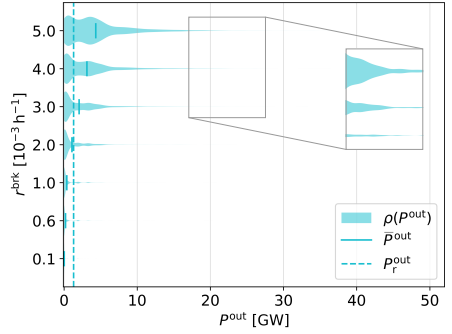
(c) Hurricane Claudette



(d) Hurricane Hanna

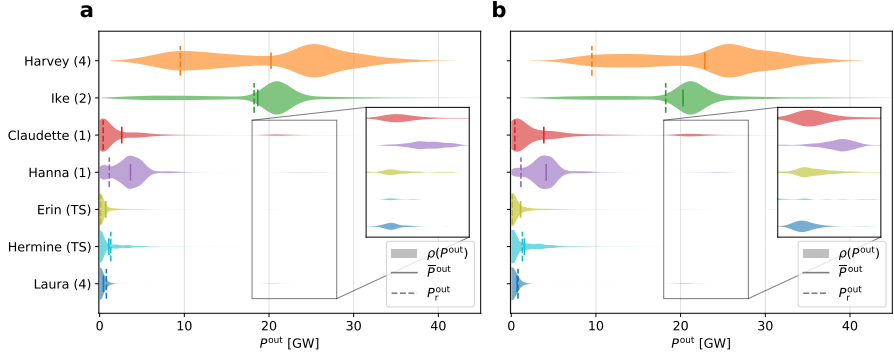


(e) Hurricane Erin



(f) Hurricane Hermine

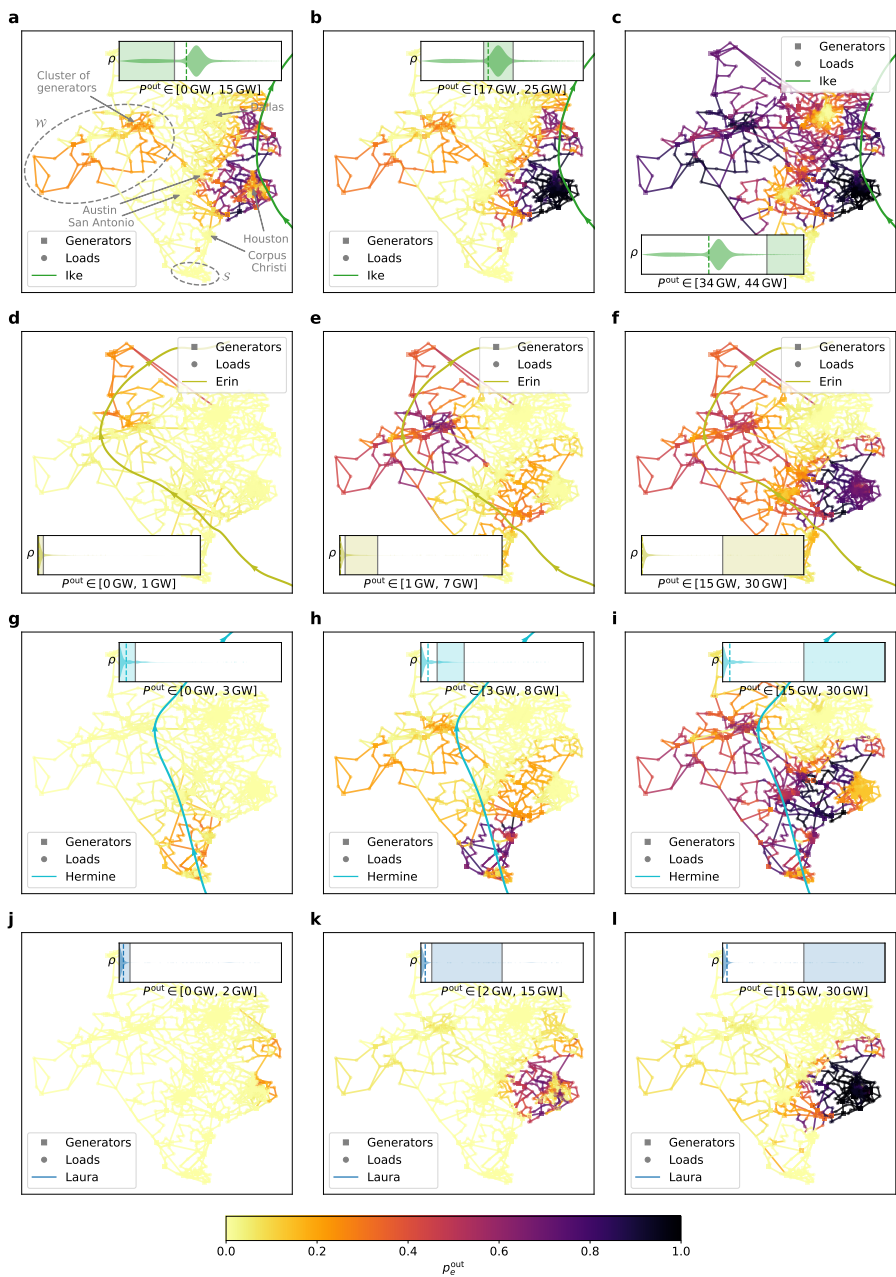
Supplementary Figure 7: (a-f) Violin plots showing the power outage distributions $\rho(P^{\text{out}})$ for all considered hurricanes and different values of the collapse rate r^{brk} (a time step of $\tau = 5$ min was used). Every shown distribution resulted from 10^4 simulation. Dashed lines indicate reported power outages P_r^{out} as listed in Supplementary Table 1 and solid lines indicate the respective mean power outage $\bar{P}^{\text{out}}$. The insets represent close-up views of the marked regions.



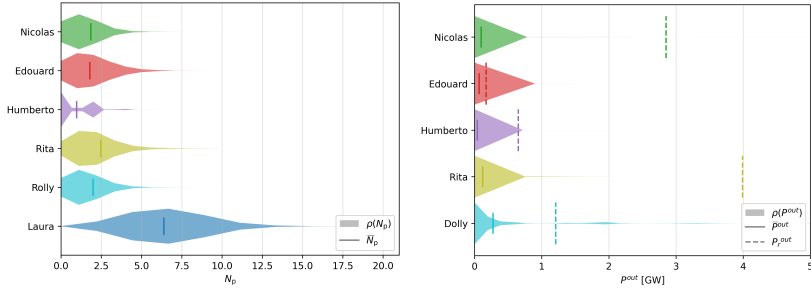
Supplementary Figure 8: Comparison of power outage distributions of fixed collapse rate with randomized ones (a) Power outage distributions for fixed collapse rate $r^{\text{brk}} = 0.002 \text{ h}^{-1}$. (b) Power outage distributions for random values of the collapse rate r^{brk} drawn uniformly from the interval $[0.0001 \text{ h}^{-1}, 0.005 \text{ h}^{-1}]$ for each transmission line and TC scenario, respectively.

in the western region $\mathcal{W}$ as they tend to occur together with comparable probabilities. For instance, this can be recognized in Supplementary Fig 9g and 9h for Hurricane Hermine.

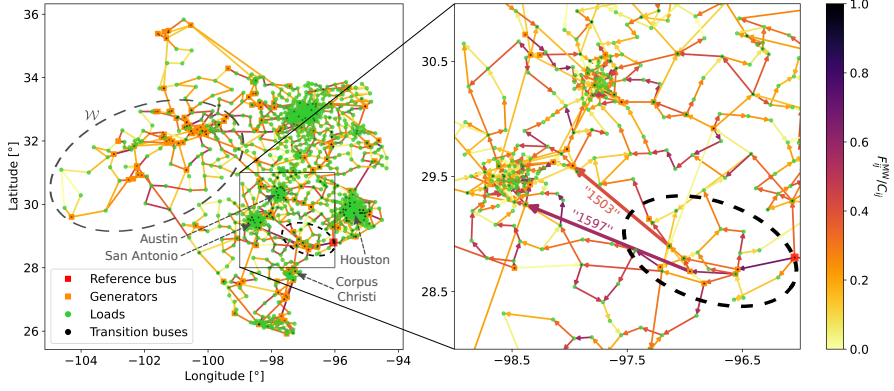
After the two lines “1503” and “1597” have been cut, a rather large cascading failure unfolds. Four iterations of this cascade are shown in Supplementary Fig. 11b. The first iteration shows the first lines that become overloaded (blue lines) in the neighborhood of the triggering lines. Up to the fourth iteration, the cascade spreads in the region between Houston and the rest of the grid leading to the formation of several islands (see reference buses shown as red rectangles). Note that it may be difficult to identify these islands by means of the depicted transmission lines since transformers within substations (not shown in Fig. 11b) can also become overloaded and consequently disconnect voltage levels from each other. In the fifth iteration, the considered cluster of generators fails as it becomes isolated from the rest of grid and the newly formed island exhibits an unavoidable overproduction. Interestingly, this represents a significant loss of generation for the remaining grids and the respective generators have to compensate it by increasing their dispatches (cf. restoration of Global active power balance (GAPB) discussed in Supplementary Note 4). However, this leads to overloads in the western region which can be seen in the inset shown for the fifth iteration (the deficit in generation that has to be compensated amounts to approximately 3.93 GW in this large connected component). These overloads then propagate through the western part of the grid and cause several outages. This can be seen in the plot of the last iteration (iteration 11).



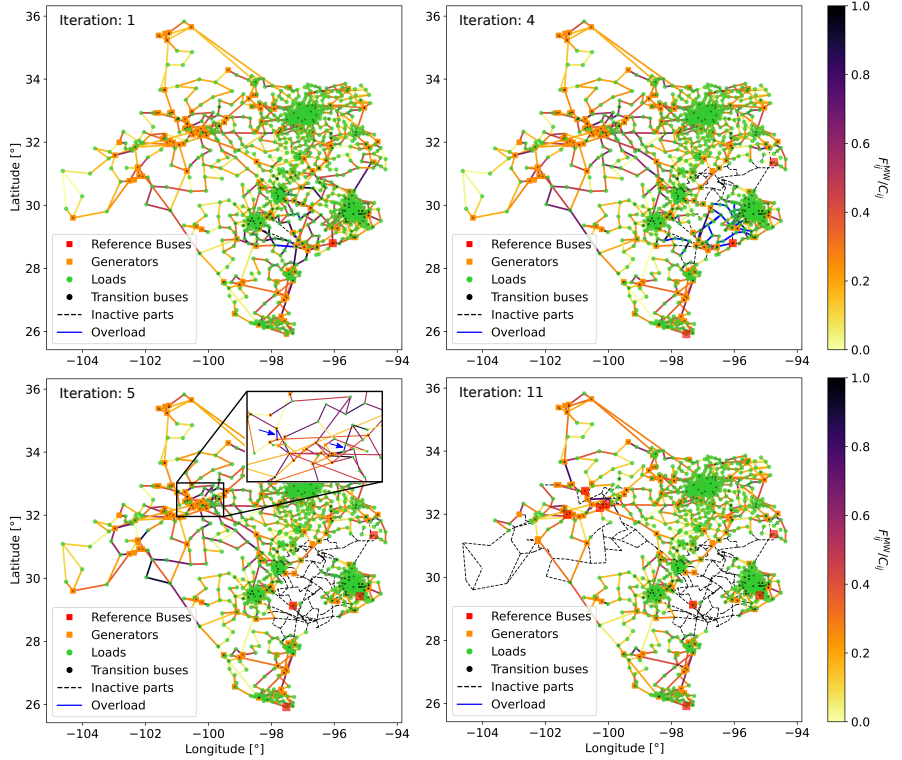
Supplementary Figure 9: Outage probabilities for Hurricanes Ike, Erin, Hermine and Laura.



Supplementary Figure 10: Total primary damages distribution and power outages distributions with collapse rate $r^{brk} = 0.002 \text{ h}^{-1}$ for hurricanes: Rita, Humberto, Dolly, Edouard and Nicholas.



(a) Generator clusters (black dashed ellipses) and the two triggers “1503”, “1597”



(b) Four iterations of the induced cascade (blue arrows highlight overloads)

Supplementary Figure 11: (a) Selection of the two triggering lines “1503” and “1597” that connect a cluster of generators (black dashed ellipse) to the central cities Austin and San Antonio. Major cities as well as the western region $\mathcal{W}$ are highlighted. The inset shows a close-up view of the triggering lines and the direction of power flow is indicated via arrows. (b) The state of the power grid for four iterations of the induced cascading failure.

Supplementary Note 6

Line priority index

As explained in Methods, we identify lines that are critical for the stability of the power grid by means of a priority index defined in Eq. (4). The probability $p_{ij}^{(\text{II})}(h)$ of a large cascading failure being triggered by the wind-induced failure of line (i, j) in a scenario of hurricane $h \in \mathcal{H}$ is calculated according to

$$p_{ij}^{(\text{II})}(h) = \frac{N_{ij}^{(\text{II})}(h)}{N_s(h)} = \frac{N(\Delta P_{ij}^{\text{out}} \geq \Delta P_{\text{th}}^{\text{out}}, h)}{N_s(h)}. \quad (\text{S13})$$

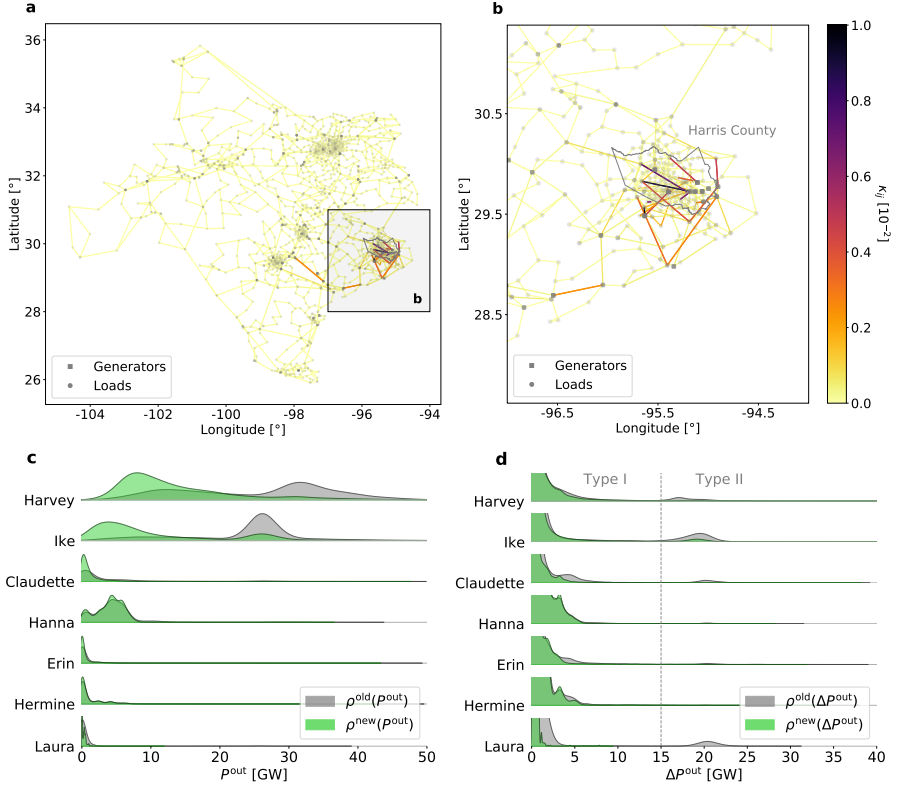
Here, $N_{ij}^{(\text{II})}(h) = N(\Delta P_{ij}^{\text{out}} \geq \Delta P_{\text{th}}^{\text{out}}, h)$ denotes the number of observed primary damage events in which line (i, j) was destroyed exclusively¹ and thereby triggered a large cascade, i.e. a cascade with an associated power outage $\Delta P_{ij}^{\text{out}}$ above the threshold $\Delta P_{\text{th}}^{\text{out}}$. The latter was in this study chosen empirically as $\Delta P_{\text{th}}^{\text{out}} = 15$ GW motivated by the cascade size distributions shown in Supplementary Fig. 5d. The number of simulated scenarios for hurricane h is denoted by $N_s(h)$ and was here always chosen as $N_s(h) = 10^4$.

It should be noted that this analysis benefits from a small time step τ in the wind fields as this decreases the probability of simultaneous wind-induced line failures. This is explained and discussed in more detail in Supplementary Note 9.

Supplementary Table 3 lists some properties of the 20 most critical lines that were identified in this study. Furthermore, it includes the respective ranks of the critical lines for the case of a randomized choice of collapse rate r^{brk} as explained in Supplementary Note 5. The table thereby reveals that the same lines belong to the top 20 except for line “1740”, which occupies rank 22 in the randomized case. Most importantly, the five most critical lines are completely identical. This shows that our results are robust to different choices of the collapse rate r^{brk} as long as they lie within the valid interval determined during the calibration in Supplementary Note 5.

Moreover, ten of the 20 most critical lines belong to the highest voltage level of 500 kV, which already suggests that they play important roles in the transmission of electricity. In fact, we find that the active power flows $|P_{ij}^{(0)}|$ carried by these lines in the initial DC state lie in the very tail of the distribution, meaning that they transport particularly large amounts of power compared to other lines in the power grid. The distribution of initial active power flows is shown in Supplementary Fig. 13a. To ensure the stability of the grid, these lines also have particularly high capacities C_{ij} (cf. distribution in Supplementary Fig. 13b). Nevertheless, the wind-induced failure of these lines can be expected to be problematic as nearby branches may not be able to absorb the rerouted power flows without becoming overloaded.

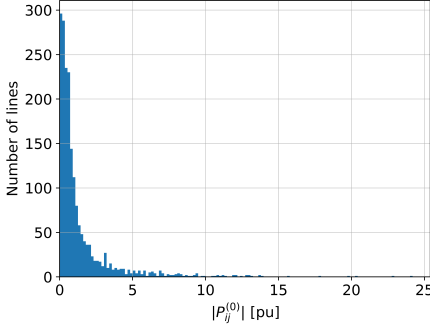
¹Only primary damage events in which no other lines than line (i, j) were destroyed can be considered because only then the subsequent power outages can be attributed to line (i, j) . Note that this still allows any kind of damage prior to the regarded primary damage events.



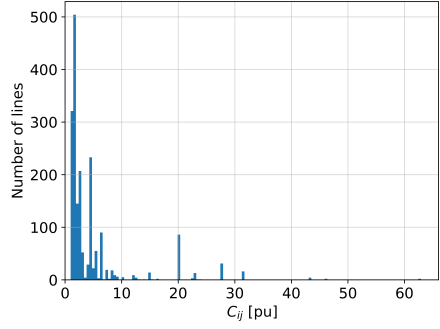
Supplementary Figure 12: Improve the resilience of Texan electric grid against hurricanes (a)-(b) Plot of the Texan electric grid with lines colored according to their priority index κ_{ij} (see Eq. (4)). Buses are shown as rectangles if they have generators connected to them or as circles otherwise (see legend). The inset b shows a close-up view of Houston and Harris County, which contain most of the critical lines. The seven most critical lines are indicated in the inset via annotations of their respective ranks (see assigned ranks in Supplementary Table 3). (c) Power outage distributions of different hurricanes for the enhanced electric grid of Texas. In both c and d, ρ^{new} shows the new probability distributions, in which 20 most critical lines are excluded from the line fragility model. The distribution of default electric grid is shown by ρ^{old} that was already considered in Fig. 3b. The data was obtained from 10^4 simulations with $r^{brk} = 0.002 \text{ h}^{-1}$ and $\tau = 5 \text{ min}$. (d) Corresponding probability densities of the cascade sizes in terms of the induced power outage ΔP_{out} . The dashed vertical line corresponds to the threshold of 15 GW that is used to differentiate between a small cascading failure (type I) and a large one (type II).

Supplementary Table 3: Properties of the 20 most critical overhead transmission lines identified in this study. Lines are ranked according to their priority indices κ_{ij} (see equation (4)) that were obtained for a homogeneous choice of $r^{\text{brk}} = 0.002 \text{ h}^{-1}$ (10^4 simulations per TC and $\tau = 5 \text{ min}$). The respective ranks and values of κ_{ij} that were obtained for the randomized choice of r^{brk} are also shown. The ID column lists the unique identifiers of the lines in the Texan data set. Columns i and j contain the indices of the from- and to-buses. Furthermore, $|P_{ij}^{(0)}|$ denotes the power flow carried by line (i, j) in the initial DC state and C_{ij} represents the respective line capacity (respecting parallel circuits). The column D_{ij} lists the line lengths and V_{ij} displays the voltage level of each line. Lines with a length below 20 km are highlighted via an asterisk in front of their rank. Last, $\Delta P_{ij}^{\text{out},(0)}$ denotes the power outage caused by the cascading failure that follows the tripping of the respective line in the initial DC state (superscript “y” indicates that at least one overloaded emerges and “n” indicates that no overload arises at all).

Homogeneous r^{brk}		Randomized r^{brk}		Line Properties							
Rank	κ_{ij} [10^{-3}]	Rank	κ_{ij} [10^{-3}]	ID	i	j	$ P_{ij}^{(0)} $ [pu]	C_{ij} [pu]	D_{ij} [km]	V_{ij} [kV]	$\Delta P_{ij}^{\text{out},(0)}$ [pu]
*1	9.54	1	10.79	“1893”	7346	7125	20.421	43.52	9.345	500	0.0 ^y
2	8.67	2	8.34	“1634”	7002	7227	11.407	31.46	48.117	500	0.0 ⁿ
3	6.64	3	6.56	“2016”	7199	7331	9.711	31.46	53.794	500	0.0 ⁿ
*4	6.10	4	6.47	“1644”	7004	7345	4.143	6.63	12.970	115	0.0 ^y
*5	5.93	5	6.27	“1820”	7087	7336	8.155	12.50	3.680	115	206.7 ^y
6	4.39	10	3.99	“1718”	7040	7077	5.740	15.00	31.247	230	11.7 ^y
7	4.33	6	4.66	“1953”	7156	7367	7.298	15.00	38.148	230	0.0 ⁿ
8	4.24	9	4.04	“2003”	7346	7186	9.380	27.68	34.913	500	0.0 ⁿ
*9	3.91	7	4.43	“1755”	7188	7055	5.899	8.84	3.088	115	200.6 ^y
10	3.79	11	3.86	“2064”	7227	7422	4.340	27.68	63.925	500	0.0 ⁿ
*11	3.49	12	3.53	“1661”	7016	7365	4.865	8.84	14.950	115	0.0 ⁿ
*12	3.46	8	4.43	“2005”	7188	7255	12.770	23.50	2.243	115	204.1 ^y
13	3.44	16	2.86	“1791”	7076	7422	5.382	20.20	47.462	500	0.0 ⁿ
14	3.10	13	3.44	“1708”	7037	7428	5.406	27.68	80.697	500	0.0 ⁿ
*15	3.07	14	3.26	“2115”	7255	7399	6.957	10.00	2.287	115	217.7 ^y
*16	2.60	15	2.91	“2067”	7265	7231	5.276	8.84	7.193	115	0.0 ⁿ
17	2.56	17	2.69	“2023”	7204	7428	3.890	20.20	89.617	500	0.0 ⁿ
18	2.37	20	2.14	“1503”	6161	7018	13.024	31.46	112.388	500	0.0 ⁿ
19	2.29	19	2.34	“1766”	7058	7095	15.745	22.95	49.555	500	0.0 ⁿ
20	2.11	22	1.81	“1740”	7052	7053	1.248	2.21	20.616	115	0.0 ^y



(a) Initial active power flows in lines



(b) Capacity of lines

Supplementary Figure 13: (a) Distribution of power flows $|P_{ij}^{(0)}|$ in the initial DC state of the Texan power grid. Power flows in parallel lines have been summed up. (b) Distribution of the line capacities C_{ij} in the considered power grid of Texas. Capacities of parallel lines have been summed up.

Surprisingly, Supplementary Table 3 also contains eight transmission lines that are part of the lowest voltage level in the grid with 115 kV. Nevertheless, these lines still carry considerably high power flows in the initial DC state which implies that their failures also hold the potential to overloaded nearby branches. The same applies to the remaining two critical lines that belong to the voltage level of 230 kV. It should be noted that almost all of the low voltage lines exhibit lengths below 20 km which makes them realistic candidates for underground cables (see ranks with asterisks in Supplementary Table 3). While the most critical line “1893” would also be short enough, its high voltage of 500 kV is typically too high for underground cables³⁵. Nonetheless, it could be enhanced by, e.g., strengthening its transmission towers, which could also be done for the other critical lines with lengths above 20 km.

It should be mentioned that eight of the 20 most critical lines already induce cascading failures if they are tripped by themselves in the initial DC state. However, only five of them actually cause power outages, while the other three lines cause overloads but no loss in supplied load. This can be seen in the last column $\Delta P_{ij}^{\text{out},(0)}$ in Supplementary Table 3 which lists the power outages associated with the cascades. Remarkably, four of the critical lines directly trigger type II cascading failures with power outages above 20 GW (due to the blackout of Houston). Hence, they already represent major vulnerabilities in the initial state of the power grid that can also destabilize the power grid during a traversing hurricane. These vulnerabilities could also be detected via a $(N - 1)$ stability analysis in which every line is tripped exclusively in the initial state and the subsequent outages are monitored. In contrast, however, 15 of the 20 most critical lines do not cause a power outage if they are tripped in the initial state. This implies that these lines only become critical if the power grid was already damaged, e.g., during a traversing hurricane. As a

consequence, one would not be able to detect these vulnerabilities by merely performing a $(N - 1)$ stability analysis. This shows that we can gain crucial insights from our simulations and highlights the importance of our model.

Ultimately, the proposed way of identifying critical lines could be expanded by including economic considerations. For this purpose, the priority index in equation (4) could be generalized to a weighted average of the form

$$\hat{\kappa}_{ij} := \alpha_{ij} \frac{\sum_{h \in \mathcal{H}} \beta_h p_{ij}^{(\text{II})}(h)}{\sum_{h \in \mathcal{H}} \beta_h}, \quad (\text{S14})$$

where α_{ij} could incorporate costs of modifications for line (i, j) that depend, for example, on the respective line length and voltage level. Furthermore, the coefficients β_h could represent weights for each hurricane $h \in \mathcal{H}$ that allow favoring adaptations to specific hurricanes (e.g., particularly strong ones or ones with specific trajectories). The used probabilities $p_{ij}^{(\text{II})}$ of type II cascading failures could also be substituted with probabilities of other specific cascades that, for example, correspond to another peak in the distribution and affect another part of the power grid. Last, the simulations could be performed as part of an economic optimization such that economic costs are minimized while providing a best possible increase of the resilience.

Supplementary Note 7

Baseline method

In the Supplementary Table 4 we compare the critical lines obtained from the static model with the lines obtained from the co-evolution model. The same lines in both models have been highlighted in red.

Supplementary Table 4: Properties of the 20 most critical overhead transmission lines in the synthetic power grid of Texas obtained from the static model and the co-evolution model for the comparison. The same lines in both models are highlighted in red. Lines are ranked according to the values of their priority indices κ_{ij} defined in equation (4) (with $r^{\text{brk}} = 0.002 \text{ h}^{-1}$, $\tau = 5 \text{ min}$, $N_s = 10^4$). The ID column contains the unique identifiers of the lines in the data set.

Rank	κ_{ij} [10 ⁻¹]	ID Static model	κ_{ij} [10 ⁻³]	ID Co-evolution model
1	9.96	“1820”	9.54	“1893”
2	7.21	“1893”	8.67	“1634”
3	3.36	“1924”	6.64	“2016”
4	3.11	“1997”	6.10	“1644”
5	2.25	“1634”	5.93	“1820”
6	2.92	“2016”	4.39	“1718”
7	2.86	“1672”	4.33	“1953”
8	2.85	“1740”	4.24	“2003”
9	2.80	“1709”	3.90	“1755”
10	2.80	“2003”	3.79	“2064”
11	2.77	“2159”	3.49	“1661”
12	2.76	“2119”	3.46	“2005”
13	2.76	“2162”	3.44	“1791”
14	2.74	“1711”	3.10	“1708”
15	2.74	“2000”	3.07	“2115”
16	2.73	“1747”	2.60	“2067”
17	2.73	“2175”	2.56	“2023”
18	2.71	“1725”	2.37	“1503”
19	2.70	“1963”	2.29	“1766”
20	2.70	“2179”	2.11	“1740”

Supplementary Note 8

Primary damage statistics

Any TC scenario with a number of N_p wind-induced line failures is given by a subset $\mathcal{F} \subseteq \mathcal{E}$ of failing lines with $|\mathcal{F}| = N_p$. The complement set $\mathcal{F}^c = \mathcal{E} \setminus \mathcal{F}$ therefore encompasses the lines that remain intact in a given scenario. It is mostly reasonable to assume that the failure or survival of a line is statistically independent of all other lines and therefore the probability of N_p destroyed lines is given by

$$p(N_p) = \sum_{\substack{\mathcal{F} \subseteq \mathcal{E} \\ |\mathcal{F}| = N_p}} \prod_{\alpha \in \mathcal{F}} \tilde{p}_\alpha \prod_{\beta \in \mathcal{F}^c} (1 - \tilde{p}_\beta). \quad (\text{S15})$$

Here, $\tilde{p}_\alpha$ denotes the overall probability with which line $\alpha \in \mathcal{E}$ is destroyed at some point during the TC. Equation (S15) is known as the Poisson binomial distribution which has the convenient property that mean μ_p and variance σ_p^2 are determined by the following sums³⁶:

$$\mu_p = \sum_{\alpha \in \mathcal{E}} \tilde{p}_\alpha, \quad (\text{S16})$$

$$\sigma_p^2 = \sum_{\alpha \in \mathcal{E}} (1 - \tilde{p}_\alpha) \tilde{p}_\alpha. \quad (\text{S17})$$

The probability densities of the number of destroyed lines N_p in Fig. 3a show the Poisson binomial distributions measured for each simulated TC, respectively.

To derive how mean and variance scale with the collapse rate r^{brk} , one has to calculate the overall failure probabilities $\tilde{p}_\alpha$ using the line segment failure probabilities p_k defined in equation (2). For a line to be destroyed in a time step $s \in \{1, \dots, N_\tau\}$, where N_τ denotes the total number of time steps, it has to survive all previous steps $s' < s$. We therefore have

$$\tilde{p}_\alpha = \sum_{s=1}^{N_\tau} \left[\prod_{s'=1}^{s-1} [1 - p_\alpha(s')] p_\alpha(s) \right], \quad (\text{S18})$$

with the probability $p_\alpha(s)$ of line α being destroyed in time step s . The latter can be expressed via the segment failure probabilities $p_k(s)$ using the complement probability $p_\alpha^c(s)$ with which line α survives the time step, i.e., all N_α line segments remain intact:

$$p_\alpha(s) = 1 - p_\alpha^c(s) = 1 - \prod_{k=1}^{N_\alpha} [1 - p_k(s)]. \quad (\text{S19})$$

Inserting equation (2) and defining the dimensionless parameter $\gamma_\tau := r^{\text{brk}}\tau$ yields

$$p_\alpha(s) = \gamma_\tau W_\alpha(s) - \frac{\gamma_\tau^2}{2} \left[W_\alpha(s)^2 - \sum_{k=1}^{N_\alpha} w_k(s)^2 \right] + \mathcal{O}(\gamma_\tau^3), \quad (\text{S20})$$

where $w_k(s) := F_k(s)/F^{\text{brk}}$ denotes the current wind load acting on segment k and $W_\alpha(s) := \sum_{k=1}^{N_\alpha} w_k(s)$ is the resulting total wind load acting on line α . The term $\mathcal{O}(\gamma_\tau^3)$ covers summands of third order and higher in γ_τ .

The overall failure probability $\tilde{p}_\alpha$ in equation (S18) is driven by time steps in which significant wind loads occur. For these time steps, however, one can assume that the term of second order in γ_τ in equation (S20) is dominated by the square of the total wind loads $W_\alpha(s)^2$. This is because $W_\alpha(s)^2$ involves $\binom{N_\alpha^*}{2}$ more summands than $\sum_{k=1}^{N_\alpha^*} w_k(s)^2$, where N_α^* denotes the number of line segments that are actually exposed to the wind field, i.e., segments with $w_k(s) > 0$. Since a line typically consists of many segments N_α , the number of exposed segments N_α^* also tends to be high. In fact, the average length of transmission lines in the synthetic power grid of Texas is given by approximately 22.6 km which implies an average of 140 segments per transmission line. Hence, we will now neglect the term $\sum_{k=1}^{N_\alpha} w_k(s)^2$ in equation (S20) and insert $p_\alpha(s)$ into equation (S18) which yields

$$\tilde{p}_\alpha \approx \gamma_\tau \sum_{s=1}^{N_\tau} W_\alpha(s) - \frac{\gamma_\tau^2}{2} \left(\sum_{s=1}^{N_\tau} W_\alpha(s) \right)^2 + \mathcal{O}(\gamma_\tau^3), \quad (\text{S21})$$

where different orders of $\sum_{s=1}^{N_\tau} W_\alpha(s)$ emerge. In fact, one can infer that the terms of third order and higher analogously lead to corresponding higher orders of this sum (the highest order being $N_\tau + N_\alpha$). These terms represent the major contributions to $\tilde{p}_\alpha$ and can be rewritten as powers of time averages $\overline{W}_\alpha$ with

$$\overline{W}_\alpha := \frac{1}{N_\tau} \sum_{s=1}^{N_\tau} W_\alpha(s). \quad (\text{S22})$$

With $N_\tau = T/\tau$ and $\gamma_\tau = r^{\text{brk}}\tau$, it follows that the overall failure probability $\tilde{p}_\alpha$ of a line α is approximately independent of time step τ as long as τ leads to accurate time averages of the total wind load. Considering the dominant terms in equation (S21), we can approximate $\tilde{p}_\alpha$ with the finite sum

$$\tilde{p}_\alpha \approx - \sum_{n=1}^{N_\tau + N_\alpha} \frac{(-r^{\text{brk}} T \overline{W}_\alpha)^n}{n!} = 1 - \sum_{n=0}^{N_\tau + N_\alpha} \frac{(-r^{\text{brk}} T \overline{W}_\alpha)^n}{n!}, \quad (\text{S23})$$

where we can identify a partial sum of the power series representation of the exponential function. Before inserting this result into equations (S16) and

(S17), it is beneficial to consider the continuous time limit $\tau \rightarrow 0$ ($N_\tau \rightarrow \infty$), which corresponds to the most accurate description of the wind field dynamics. Hence, it should lead to results that are ideally also captured by our discrete time model. With $N_\tau \rightarrow \infty$ equation (S23) yields the exponential function

$$\tilde{p}_\alpha \approx 1 - e^{-r^{\text{brk}} T \bar{W}_\alpha}, \quad (\text{S24})$$

where the average total line wind load $\bar{W}_\alpha$ is now given by

$$\bar{W}_\alpha = \frac{1}{T} \int_0^T W_\alpha(t) dt. \quad (\text{S25})$$

Interestingly, the complementary probability $\tilde{p}_\alpha^c = 1 - \tilde{p}_\alpha = e^{-r^{\text{brk}} T \bar{W}_\alpha}$, which represents the probability of survival for line α , can now be identified as a Poisson distribution with average collapse rate $r_\alpha^{\text{brk}} := r^{\text{brk}} \bar{W}_\alpha$ and event count $k = 0$, meaning that the line is not destroyed during the hurricane with duration T . Inserting the total failure probability in equation (S24) into equations (S16) and (S17) yields the following approximations for the mean number of destroyed lines and the variance:

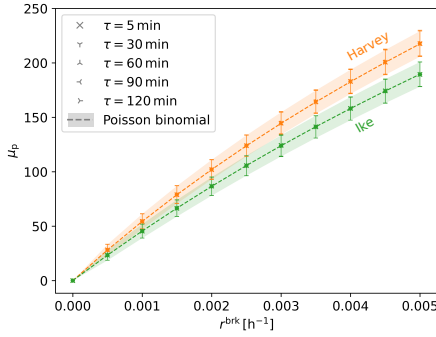
$$\mu_p(r^{\text{brk}}) \approx N^* - \sum_{\alpha \in \mathcal{E}^*} e^{-r^{\text{brk}} T \bar{W}_\alpha}, \quad (\text{S26})$$

$$\sigma_p^2(r^{\text{brk}}) \approx \sum_{\alpha \in \mathcal{E}^*} e^{-r^{\text{brk}} T \bar{W}_\alpha} \left(1 - e^{-r^{\text{brk}} T \bar{W}_\alpha}\right), \quad (\text{S27})$$

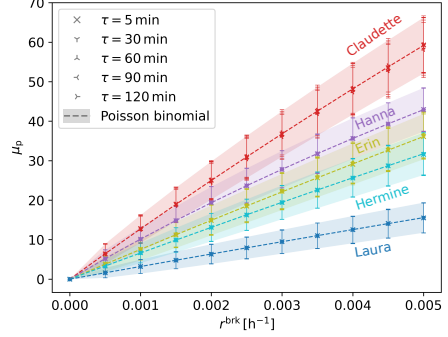
with the subset of lines $\mathcal{E}^* \subseteq \mathcal{E}$ that are at some point exposed to a given TC, meaning that $\bar{W}_\alpha > 0$ for all $\alpha \in \mathcal{E}^*$. The number of overhead transmission lines hit by the TC is denoted by $N^* := |\mathcal{E}^*|$ and represents an upper limit for mean μ_p .

To verify the validity of equations (S26) and (S27), Supplementary Fig. 14 shows the theoretical scaling of mean μ_p and variance σ_p^2 with collapse rate r^{brk} together with simulation results. The simulation data was acquired by applying our line fragility model to the considered TCs using different time step sizes τ (ranging from 5 min to 120 min, see legend) and running 10^4 simulations for different values of the collapse rate r^{brk} , respectively. In each simulation the number of destroyed lines N_p was counted. Thus, a good estimate of the mean μ_p and the standard deviation σ_p could be determined for each parameter set (r^{brk}, τ) . In contrast, the theoretical mean was calculated by evaluating equation (S26) for the considered values of r^{brk} using the average line wind loads defined in equation (S22) with $\tau = 5$ min.

First of all, we notice that the points representing the simulation data for different time step sizes τ lie on top of each other for all values of the collapse rate r^{brk} (including their error bars which represent the observed standard deviation). Only the data for Hurricane Claudette exhibits very small deviations in that regard. This shows that the total primary damage statistics in



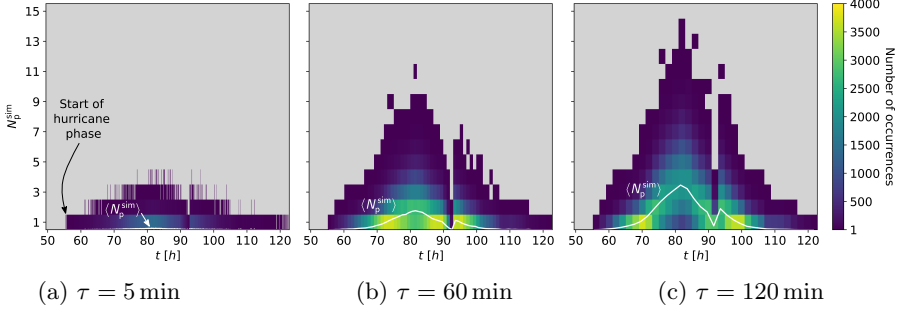
(a) TCs with stronger impact



(b) TCs with weaker impact

Supplementary Figure 14: Primary damage statistics. Plots of the mean number of destroyed lines μ_p versus the collapse rate r^{brk} for the stronger hurricanes in (a) and the weaker ones in (b). The data points with error bars show simulation results obtained by applying the line fragility model to the individual hurricanes using different time step sizes τ (see legend) and sample size 10^4 , respectively. The error bars represent the observed mean of datasets and standard deviations, i.e. $\pm\sigma_p$. In addition, the dashed lines and the shaded regions show the theoretical scaling of μ_p and σ_p according to the Poisson binomial distribution for each hurricane, respectively (see equations (S26) and (S27)).

our simulations are indeed approximately independent of τ . Furthermore, we find that the theoretical curves according to equations (S26) and (S27) represent seemingly perfect fits to the simulation data for each hurricane. We can therefore conclude that these equations constitute very good approximations. In fact, we can argue in terms of the total primary damage statistics that all time resolutions τ are viable as long as they do not show large deviations from the results obtained in the continuous time limit. This goes hand in hand with the fact that viable time step sizes have to preserve accurate time averages $\bar{W}_\alpha$ defined in equation (S22). The latter can be expected even for time step sizes of 1 h and above due to the large spatial extent of hurricanes and their rather slow movement. More specifically, the large size of a hurricane and its slow movement leads to a long duration of wind exposure for each affected transmission line. For example, a line of 20 km length can be exposed to a hurricane with a diameter of 500 km and a translational speed of 20 km h⁻¹ for up to 26 h. The role of the time resolution is further discussed in Supplementary Note 9.



Supplementary Figure 15: 2D histograms showing how often a specific number of lines N_p^{sim} is destroyed simultaneously as a function of time t during Hurricane Claudette. The data was obtained respectively from 10^4 simulations with a collapse rate of $r^{\text{brk}} = 0.003 \text{ h}^{-1}$ and three different time step sizes $\tau = 5 \text{ min}$ (a), $\tau = 60 \text{ min}$ (b) and $\tau = 120 \text{ min}$ (c). Each histogram is accompanied by a line plot (white) that shows the average number of simultaneous wind-induced failures $\langle N_p^{\text{sim}} \rangle$ as a function of time (disregarding cases of no damage). Grey regions corresponds to a count of zero. The start of the hurricane phase is indicated in (a).

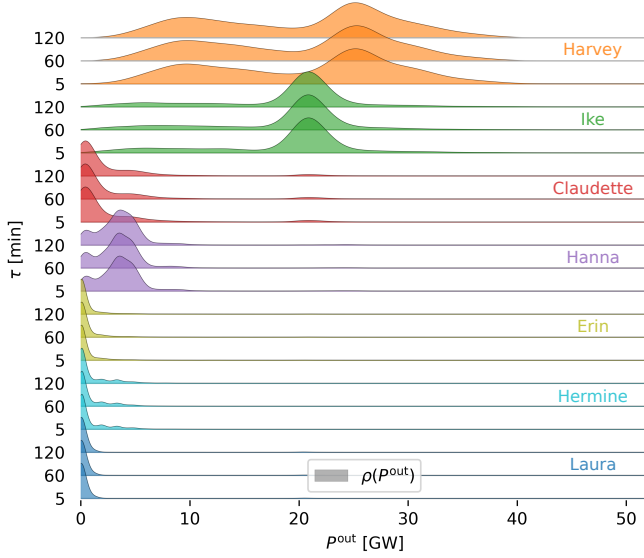
Supplementary Note 9

Role of the time resolution

All simulations of wind fields in the paper were conducted with a temporal resolution of $\tau = 5 \text{ min}$. In Supplementary Note 8 it was shown that a variation of the time resolution does not change the total primary damage statistics but merely influences how many simultaneous wind-induced damages occur on average (lower time resolutions lead to more simultaneous damages in our simulations). Supplementary Fig. 15 depicts the number of simultaneous line damages for three different temporal resolutions.

Whether lines fail simultaneously or consecutively can have a large influence on the subsequent cascade of failures and consequently also on the resulting power outage. Therefore it would be theoretically possible that there are also noticeable differences in the power outage distributions. Supplementary Fig. 16 shows the power outage distributions obtained for $\tau = 5 \text{ min}$, $\tau = 60 \text{ min}$ and $\tau = 120 \text{ min}$. Surprisingly, we find that all three time resolutions lead to practically identical distributions for all considered hurricanes.

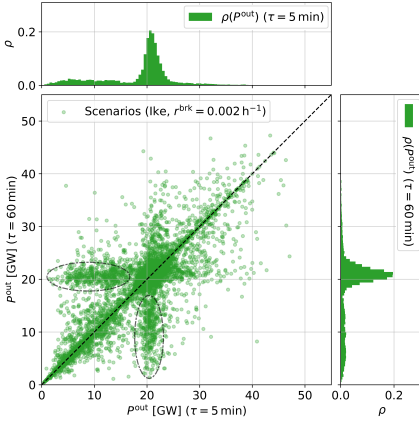
In order to gain a better understanding of how the time resolution affects an individual scenario, we make use of the fact that a hurricane scenario with a time resolution of $\tau = 5 \text{ min}$ can also be reinterpreted as a scenario with lower resolution by aggregating groups of subsequent time steps. For example, let us consider 12 subsequent time steps in a scenario with $\tau = 5 \text{ min}$ that would constitute a single time step for $\tau = 60 \text{ min}$. If we assume for the sake of simplicity that the considered time steps encompass two primary damage events that each involve the destruction of a single line, then these two events



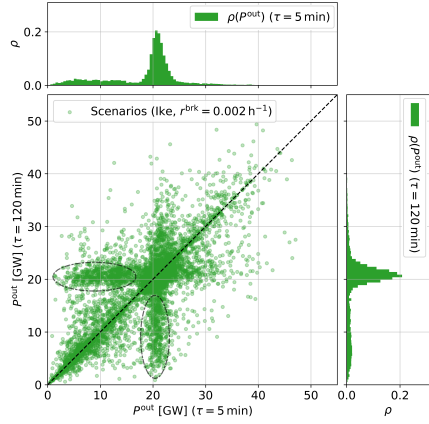
Supplementary Figure 16: Power outage distributions $\rho(P^{\text{out}})$ of all considered hurricanes for different time step sizes τ in the wind fields. The data was obtained from 10^4 simulations with $r^{\text{brk}} = 0.002 \text{ h}^{-1}$, respectively. The names of the different hurricanes are specified on the right side of the plot.

would be merged into one event in the 60-min-picture in which both lines are destroyed simultaneously. Based on these considerations, we reran 10^4 5-min-scenarios of Hurricane Ike as corresponding scenarios with $\tau = 60 \text{ min}$ and $\tau = 120 \text{ min}$ by aggregating groups of primary damage events that belong to 12 and 24 subsequent time steps, respectively. Comparisons of the resulting power outages are shown in figures 17a and 17b while comparisons of the resulting outage probabilities of grid elements are shown in figures 17c and 17d. The scatter plots in figures 17a and 17b illustrate that the different interpretations indeed lead to different power outages in most cases. However, there is no discernible trend indicating that scenarios with a lower time resolution tend to result in lower or higher power outages in general. Instead, the data points scatter rather symmetrically around the diagonal with a slope of one, which represents a perfect match. The respective power outage distributions therefore look the same for all considered time resolutions. Remarkably, there are scenarios in which Houston suffers a blackout for one of the considered time resolutions while remaining intact for the other one. These scenarios are highlighted via dash-dotted ellipses in figures 17a and 17b.

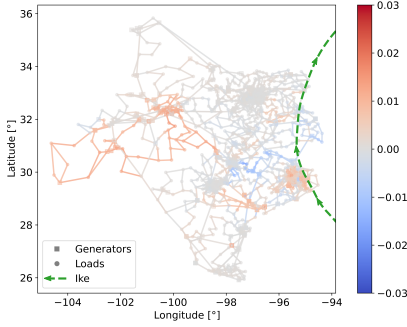
The comparisons of the outage probabilities in figures 17c and 17d reveal that specific parts of the power grid exhibit outage probabilities in the 5-min-picture differ from the outage probabilities in the 60-min- and 120-min-picture. We find that the area of Houston as well as the vulnerable part in the western region seem to be slightly more prone to failure for lower time resolutions.



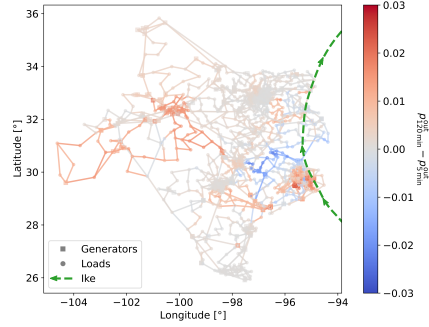
(a) Comparison of power outages ($\tau = 5$ min and $\tau = 60$ min)



(b) Comparison of power outages ($\tau = 5$ min and $\tau = 120$ min)



(c) Comparison of outage probabilities ($\tau = 5$ min and $\tau = 60$ min)



(d) Comparison of outage probabilities ($\tau = 5$ min and $\tau = 120$ min)

Supplementary Figure 17: (a), (b) Scatter plots of the final power outages P^{out} that arise in scenarios of Hurricane Ike for different time resolutions τ . The data in (a) was obtained by reinterpreting primary damage scenarios with $\tau = 5$ min as scenarios with $\tau = 60$ min and running the DC model, respectively. Analogously, the data shown in (b) was acquired for $\tau = 120$ min. The dashed diagonal lines have a slope of one, which indicates a perfect match. Both plots are accompanied by histograms that show the respective power outage distributions $\rho(P^{\text{out}})$. The dash-dotted ellipses encircle scenarios in which Houston fails for one time resolution while surviving for the other. (c), (d) Plots of the Texan power grid with buses and lines colored according to the respective difference in outage probability P^{out} . The data was extracted from the same scenarios considered in (a) and (b).

The same applies to the cluster of generators close to Houston. In contrast, the region northwest of Houston (between Houston and Austin) shows slightly higher outage probabilities for $\tau = 5$ min. Nevertheless, the observed deviations are always below 3% and therefore do not seem to impact the power outage statistics notably.

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