Responses to the Feedback

Thanks for the Great Feedback!

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Prepared for

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Q1: Number of DERs

Proposal: The growing integration of distributed energy resources (DERs) in urban distribution grids raises various reliability issues due to complex uncertainties.

Mr. Han: I don’t think we’re saturated with enough DER to really understand what the potential effects are yet.

Response: This is a nice comment and thank you. The picture below shows the solar installation condition in Santa Ana four years ago. Given the fact that the data was from one vendor (SunPower) and it was four years ago, there are a lot of solar systems in SCE today. For example, the figure on the right-hand side shows the residential growth in CA. Also, DER also includes electric vehicles and storage devices, the penetration can be quite high in some feeders of SCE.

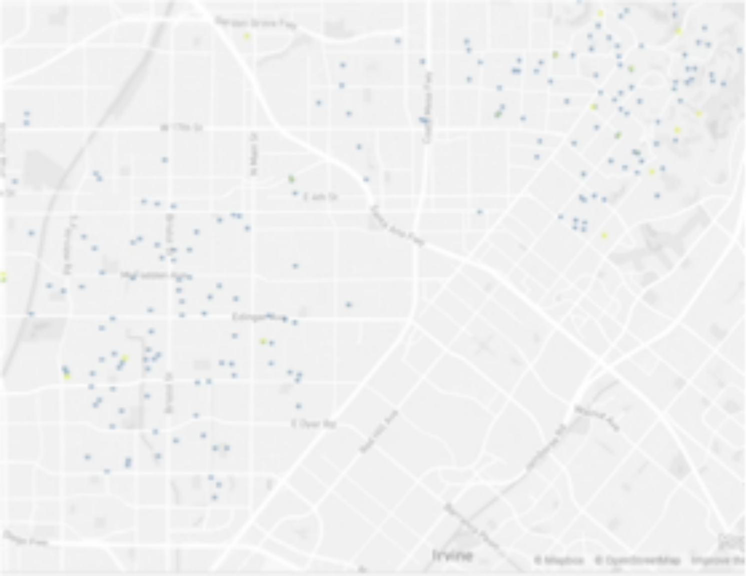
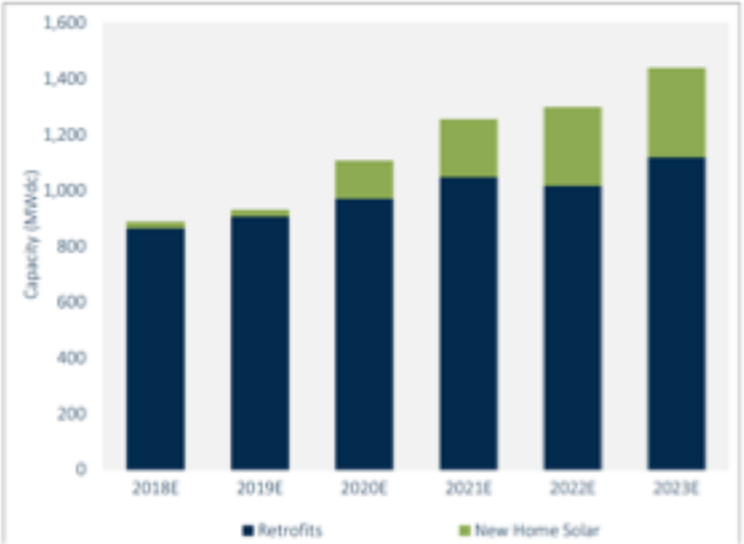


Figure 1.2 California Residential PV Forecast 2018-2023 – Retrofit vs. New Home Solar



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Q1: Number of DERs

Mr. Han: This isn't just a technological issue, but depending on how we operate the grid, will also likely determine how much of an impact we'll see from the DERs.

Response: Great suggestion! Therefore, we can start this work to quantify the DER's impact on SCE Outage in Short Term.

Mr. Han: There also needs to be a mention of whether this would be focused solely on distribution level DERs.

Response: Our method can be on both distribution grid and transmission grid. Depending on the needs of your Reliability Ops Center, we are happy to put priority to the way you like.

Q2: Islanding

Proposal: With the large-scale penetration of DERs, traditional outage detection methods, which rely on customers making phone calls and smart meters' "last gasp" signals, will have limited performance because 1) the renewable generators can supply powers after line outages

Mr. Han: Unless we change the way we operate, as far as I know other than maybe enable low-voltage ride through capabilities, we still do not allow for islanding

Response: It is great to know that SCE does not allow for islanding. In the proposal, we can remove the islanding part. However, we would like to emphasize that the islanding in the proposal is more of a passive islanding mode that the residential customers do not intend to do. In such an undesirable situation, the temporary islanding can make the outage detection fail. This means some delay in detection with a potential hazard to the grid. So, it is still useful for SCE in such scenarios. Enabling low-voltage ride through capability is also what our algorithm can handle.

Q3: Mesh Structure

Proposal: and 2) many urban grids are mesh and line outages do not affect power supply

Mr. Han: Unless we change the way we operate we do not typically operate in the concept of mesh, except for long beach, where we have downstream distribution substations have looped fed systems, or system parallels.

Response: We mentioned the mesh network structure, because we know such a structure in some utilities. With more DERs, some utilities also plan to increase the mesh structure in their territory. Therefore, the capability of handling the mesh structure is a selling point. But, if SCE does not need it, we can remove it. If SCE would like to test it in long beach, we are more than happy to do so.

Q4: Time–Series Data

Proposal: To address these drawbacks and to accommodate SCE's interest in outage detection, our idea is to propose a new data-driven outage monitoring approach based on the stochastic time series analysis with the newly available smart meter data utilized.

Mr. Han: We are already doing this, and when we further get SCADA data more in real-time, we can further improve our current capabilities.

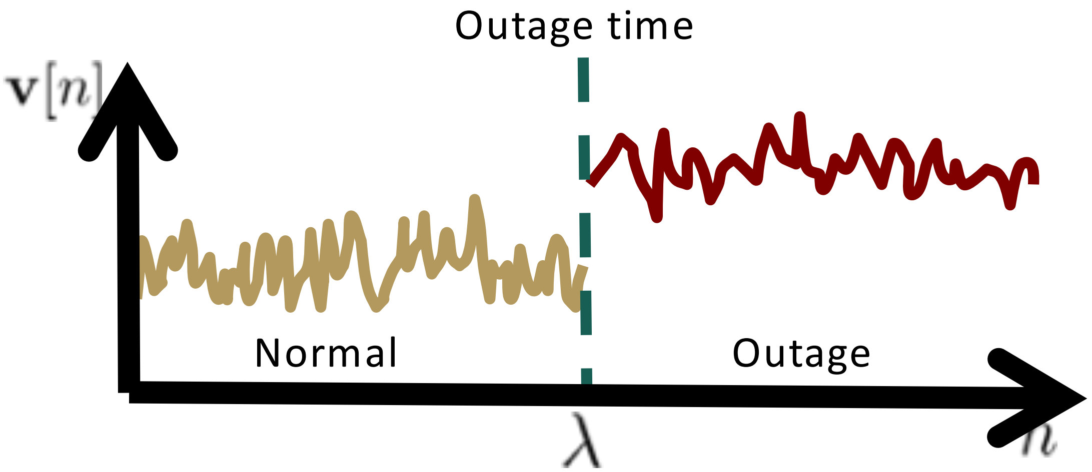
Response: We agree that using time series data is not our contribution. However, the way of how we use the data has limited assumptions and great advantages over the other methods. These advantages include

(1) we do not need network admittance matrix and we do not need state estimation,
(2) We can provide highly accurate detection, even when the voltage drops are small after outages, e.g., passive islanding for a moment. In such a case, the threshold method cannot report an outage event. For our method, we solve this problem by utilizing the data properties hidden with in voltage measurements and the distribution grid.
(3) we can detect power outage with a few data sources (low observability) and a limited amount of data (data delay, data loss, and low data storage)
(4) we can localize the outage based on the time series data with theoretical guarantees.

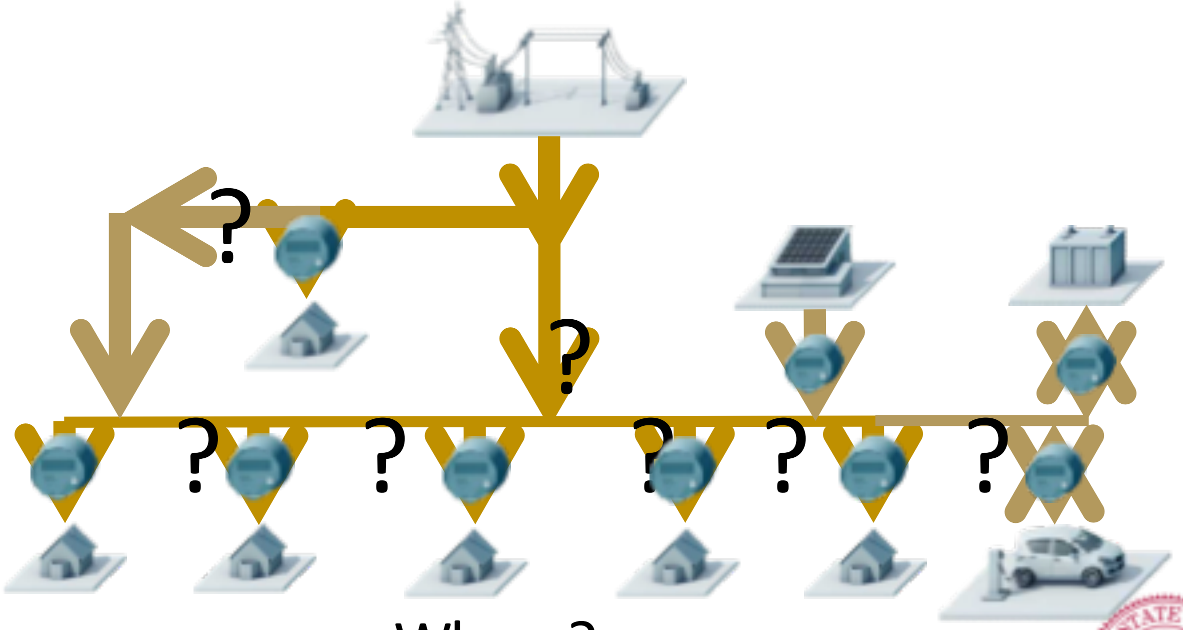
Q4-2: Short Introduction to Our Method

Time-series Voltage Magnitude

$$\mathbf{v}^{1:N} = \{\mathbf{v}[1], \mathbf{v}[2], \cdots, \mathbf{v}[N]\}$$



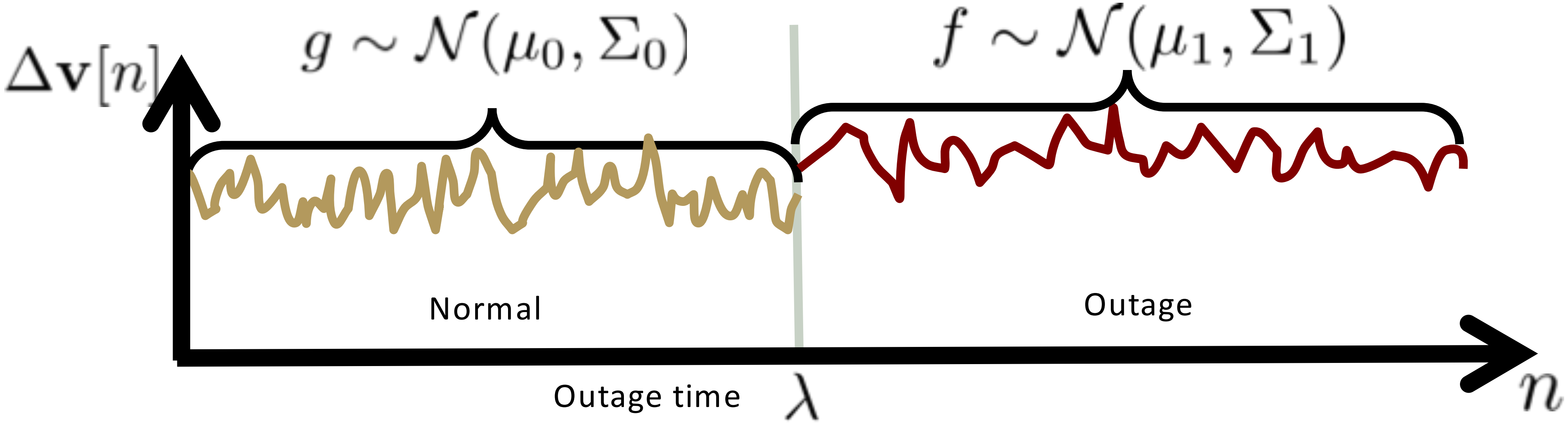
When?



Where?

Q4-2: When

$$\mathbf{v}^{1:N} = \{\mathbf{v}[1], \mathbf{v}[2], \cdots, \mathbf{v}[N]\}$$



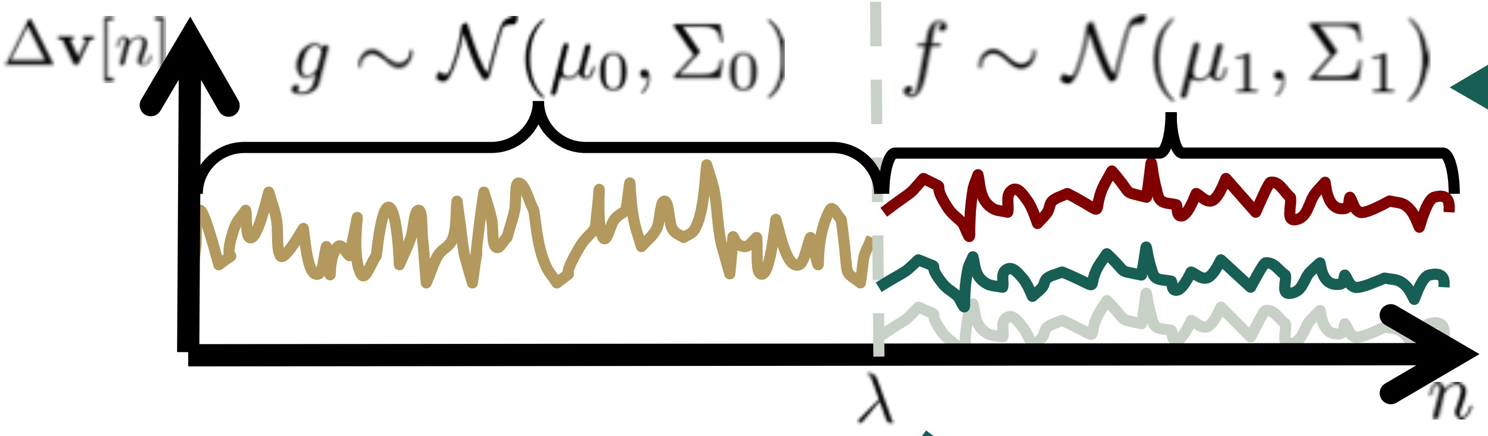
Data Likelihood Ratio Test

$$\Lambda(\Delta \mathbf{v}^{1:N}) = \frac{P(Outage|\Delta \mathbf{v}^{1:N})}{P(Normal|\Delta \mathbf{v}^{1:N})}$$

Outage: 10^4, 10^5, 10^6

Normal: 0.1, 1, 10

Q4-2: When, Theoretic Guarantee



Learn from data

$$\hat{\mu}_1 = \frac{1}{N}\sum_{n=1}^{N} \Delta\mathbf{v}[n]$$

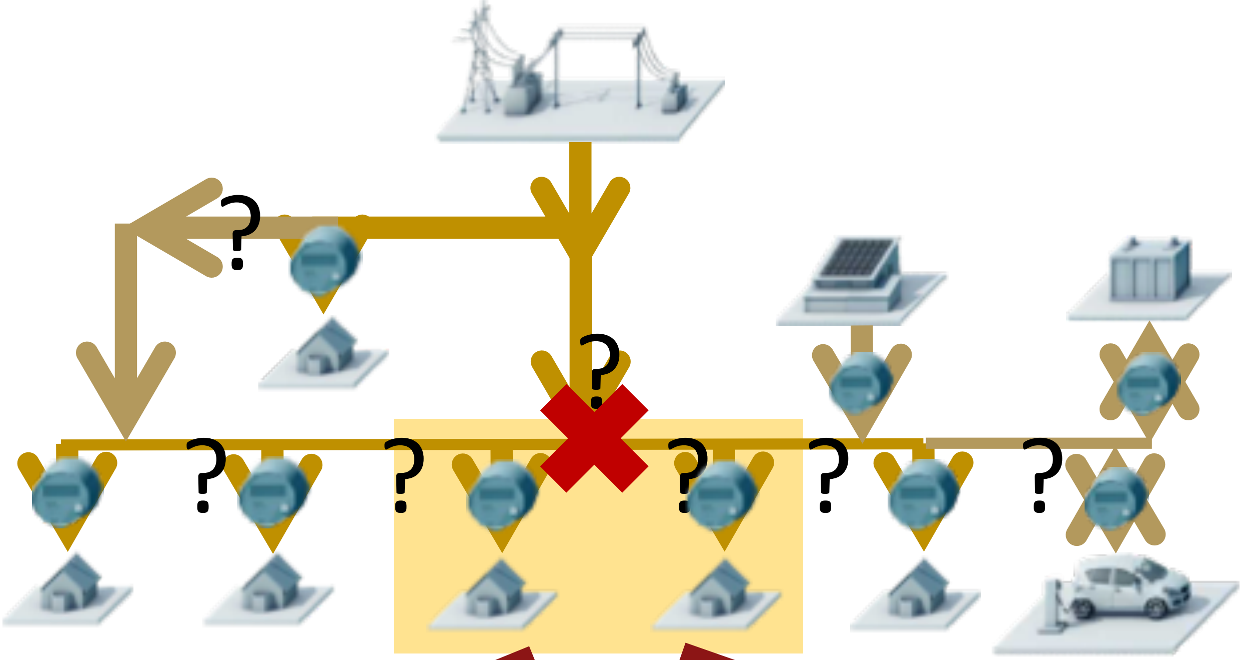
$$\widehat{\Sigma}_1 = \frac{1}{N}\sum_{n=1}^{N} (\Delta\mathbf{v}[n] - \hat{\mu}_1)(\Delta\mathbf{v}[n] - \hat{\mu}_1)^T$$

Voltage Exception Only has part of our Info.

$$\max \quad \log \Lambda(\Delta\mathbf{v}^{1:N}) = \log \frac{\sum_{k=1}^{N} \boxed{\pi_\lambda(k)} \prod_{n=k}^{N} \frac{f(\Delta\mathbf{v}[n])}{g(\Delta\mathbf{v}[n])}}{\sum_{k=N+1}^{\infty} \pi_\lambda(k)}$$

Non Convex! → Convexification

Q4-2: Where, Theoretic Guarantee



Theorem

Proof omitted

$$\mathrm{cov}(\Delta V_i, \Delta V_j | \{\Delta V_k, k \notin \{i,j\}\}) = 0$$

Conditional Covariance → 0 ⟷ Outage

Q5: Require Network Model

Proposal: Specifically, based on the power flow analysis, we prove that the statistical dependency of time-series voltage measurements has significant changes after line outages.

Mr. Han: This requires a good network model.

Response: Our proof is based on the network model. However, the algorithm does not need the network model, as it is purely data-driven. This is the beauty of our algorithm. For example, the following data was what we used for one utility project. It has voltage only.

Feeder AC122	Total meter number	Total data number	Starting time	Ending time	Units
January	153	$153 \times 2,976 = 455,328$	2018-01-01 00:15	2018-02-01 00:00	Volt
February	165	$165 \times 2,688 = 443,520$	2018-02-01 00:15	2018-03-01 00:00	Volt
March	171	$171 \times 2,976 = 508,896$	2018-03-01 00:15	2018-04-01 00:00	Volt
April	173	$173 \times 2,880 = 498,240$	2018-04-01 00:15	2018-05-01 00:00	Volt
May	195	$195 \times 2,976 = 580,320$	2018-05-01 00:15	2018-06-01 00:00	Volt
June	199	$199 \times 2,880 = 573,120$	2018-06-01 00:15	2018-07-01 00:00	Volt
July	207	$207 \times 2,976 = 616,032$	2018-07-01 00:15	2018-08-01 00:00	Volt
August	209	$209 \times 2,976 = 621,984$	2018-08-01 00:15	2018-09-01 00:00	Volt
September	210	$210 \times 2,880 = 604,800$	2018-09-01 00:15	2018-10-01 00:00	Volt
October	212	$212 \times 2,976 = 630,912$	2018-10-01 00:15	2018-11-01 00:00	Volt
November	213	$213 \times 2,880 = 613,440$	2018-11-01 00:15	2018-12-01 00:00	Volt
December	213	$213 \times 2,976 = 633,888$	2018-12-01 00:15	2019-01-01 00:00	Volt
All Feeders	80,490	$80,490 \times 2,976 = 239,538,240$	2018-12-01 00:15	2019-01-01 00:00	Volt

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Q6: Measurement Locations

Proposal: Specifically, based on the power flow analysis, we prove that the statistical dependency of time-series voltage measurements has significant changes after line outages.

Mr. Han: This also depends on what voltage measurements they're referring to, but it's likely at both the substation and the smart meters, and possibly wherever other distribution devices that have voltage are.

Response: Right. For our method, it does depend on voltage measurements. However, we are quite flexible. If there are more voltage measurement locations, we can localize exactly where the outage is. If there are limited voltage measurement locations with a lot of unmeasured buses, our algorithm can still rough quantify the outage location. This shows strong robustness of our algorithm. Because we have proved the one-to-one mapping between the line outage and the change of statistical data properties embedded within the voltage data, we can easily localize the out-of-service power line only using voltage measurements.

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Q7: Network Model, PSLF, OpenDSS

Proposal: Hence, we use the optimal change point detection theory to detect and localize line outages. As the existing change point detection methods require the post-outage voltage distribution, which is unknown in power systems, we propose a maximum likelihood method to learn the distribution parameters from the historical data and then enforce the outage detection algorithm.

Mr. Han: Again this requires a good network model since they really want to do a state estimation-esque model by running it within power simulation software such as PSLF and OpenDSS.

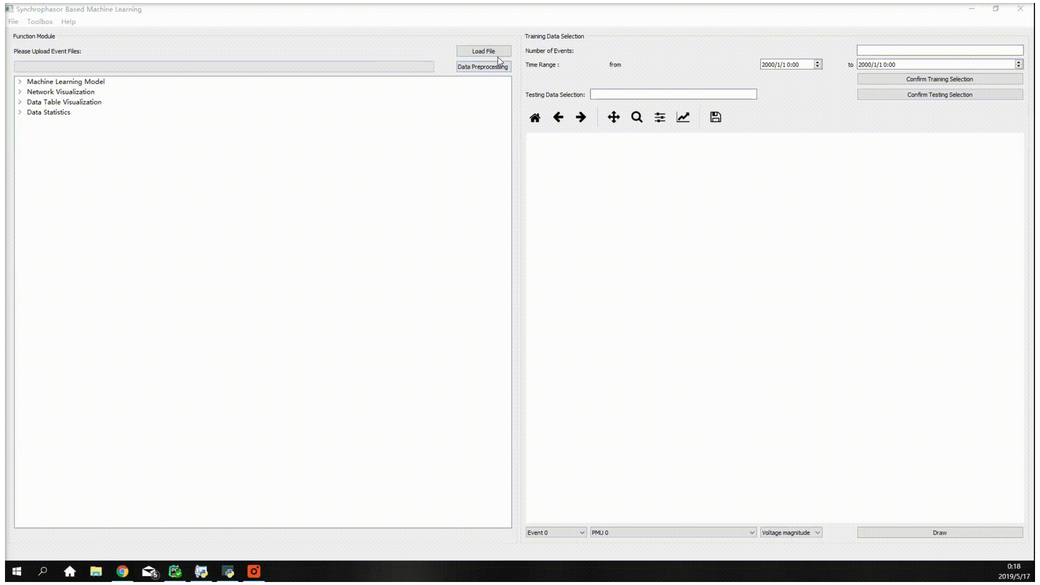
Response: We can explain the paper to show that we do not need a network model. Also, we do not need PSLF on the transmission grid and OpenDSS in the distribution grid.
Specifically, our data distribution does not require physical model. The distribution refers to the statistical distribution of the time series data. The parameters refer to the parameters that uniquely determine the distribution shape. For example, a Gaussian distribution can be with mean 0 and variance 1. Here, Gaussian distribution is the distribution family. 0 and 1 are the parameters. One advantage of our method is that we do not need the system model. This is because the system model is hidden in the measurements and we propose to use the measurement to obtain the outage information rather than recover system information and do the outage detection in the second stage. Such a learning method is quite popular in the artificial intelligence area.

Q7: Network Model, PSLF, OpenDSS (Continue)

Response: A good advantage of our algorithm is model-free. Specifically, in our paper, we prove the connection between the change of data measurements and power system equations. Then, for the field applications, the exact system model (e.g. grid topology, line impedance) is not needed. To detect outage, our algorithm only needs the bus measurements (AMI & SCADA data). This model-free feature makes our algorithm flexible for various types and sizes of distribution grids.

Finally, our group is quite good at using PSLF and OpenDSS. For example, the software on the left is developed for EPRI based on PSLF for machine learning on event detection. The right one is for primary and secondary distribution (down to 120V) grid topology recovery based on smart meter data and OpenDSS. **However, the proposed work to SCE does not use PSLF and OpenDSS.**

The figure is a video if slide is in play mode



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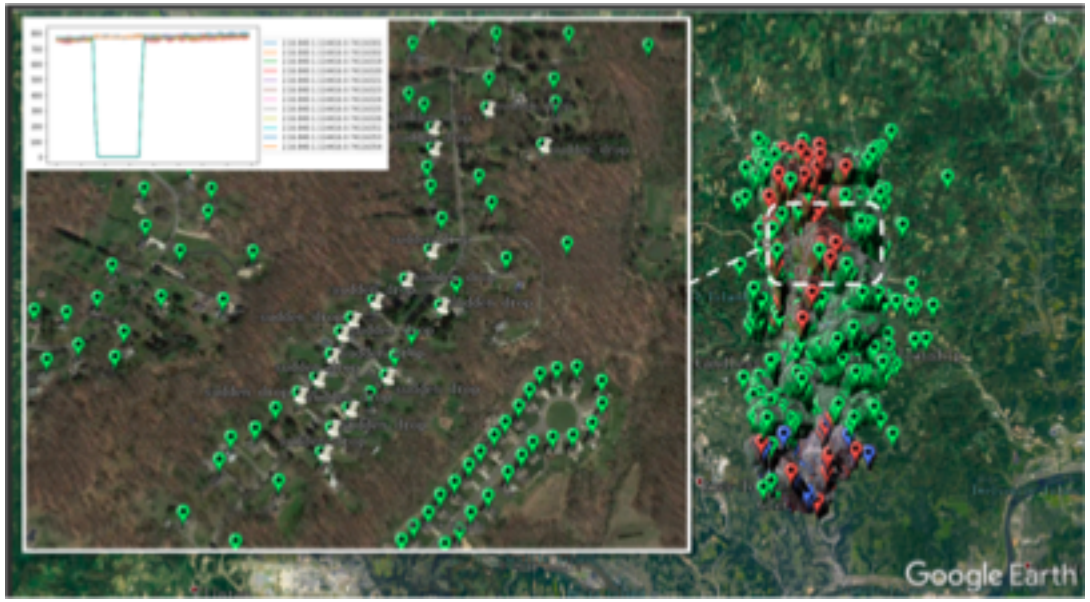
Q8: Last Gasp and Voltage Exception

Proposal: Many current power outage assessments rely on customers making phone calls to report an incident to the Customer Information System, from which the Outage Management System obtains the information and dispatches crews to the field to identify outage areas. They often receive delayed and imprecise outage information, making outage detection and power restoration slow and inefficient. The recent deployment of advanced metering infrastructure(AMI) enables smart meters to send a “last gasp” message when there is a loss of power

Mr. Han: With the focus still being on “last gasp”, voltage exception data is still being ignored (the other utilities they worked with probably aren’t using them), example would be single phase outages in which a mix of power downs and volt below thresholds may be present, the voltage exceptions further enhance the ability to determine location and potential incident type as we’ve already demonstrated).



Response: This proposal state "last gasp" as a review of what is available on the market. We are not using "last gasp" as part of our algorithm. Instead, we aim at how to remove the limitation of current methods, including "last gasp". Also, voltage exception data is important and our algorithm uses such information as well. For example, the right figure is a scenario, where voltage except, or voltage mean change is good enough in one of our work with utilities.

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Q8: Last Gasp and Voltage Exception (Continue)

Continued Response: Our method goes much further beyond the voltage exception data. In our collaboration with other utilities, who are also using voltage exception data for outage data, a particular issue they are facing is that the magnitude of voltage drops after outage is small and the threshold is hard to set for all outage cases. Therefore, we propose this new solution with theoretic guarantee to overcome the drawback of a fixed threshold and make the outage algorithm flexible to all outage cases. For example, rather than using instantaneous voltage measurements and voltage exception data from a single bus or a small subset of bus, we use all available data within the distribution grid to diagnose the outage condition. In addition, the voltage drop after outages is considered as the change of the average voltage data. To increase the accuracy and reduce the outage detection delay, we use the historical measurements and the data variance to enhance the detection algorithm. In our theoretical analysis and the engineering validation with utility partners, the detection delay can be reduced by 20% and the incorrect detection rate is decreased by 10%. Based on the feedback of our current utility partners, the long response time and incorrect crew dispatch are all high-cost events for their operation.

In other words, we use statistical distributions, which include the change of distribution. For describing a distribution, there are statistics, called mean, variance, Skewness, etc. We use all of this information coming from the data. Therefore, voltage exception is part of our detection and we did not ignore it. However, our algorithm is much better. For example, outages can create a mix of power downs and volt below thresholds. How to define the threshold may be heuristic and not reliable 100%. In summary, our method not only includes more information from the data, e.g., variance, skewness, test, but also provides a theoretical guarantee, so that the system operator can use it with confidence. It can avoid miss detection and false alarm.

Q9: Solar System Operation at SCE

Proposal: In addition, the fault location, isolation, and service restoration (FLISR) technologies and systems have been adopted by the utilities in the U.S., which can further reduce the impact and duration of power interruptions. With the integration of DERs, the approaches above will have limited performance. For example, if rooftop solar panels are installed at the customers' premises, the customer can still receive power from renewable generators when there is no power flow in the distribution circuit connecting to the premises.

Mr. Han: As far as I know this is not the way we allow customers to run their solar systems, which renders the next statement false. [Proposal: So the (AMI) smart meter at the customer premises cannot detect a power outage. Also, in metropolitan areas, such as Los Angeles, New York City, and San Francisco, the secondary distribution grids are mesh networks. Hence, a branch outage will not necessarily cause a power outage. However, the distribution grid system operators still need to detect, localize, and identify the out-of-service branches.]

Response: It is great to know that SCE does not allow for islanding. In the proposal, we can remove the islanding part. However, we would like to emphasize that the islanding in the proposal is more of a passive islanding mode that the residential customers do not intend to do. In such an undesirable situation, the temporary islanding can make the outage detection fail. This means some delay in detection with a potential hazard to the grid. Also, we want to highlight the flexibility of our algorithm for handling the unintended islanding impact in the residential distribution grids.

Summary

- It is good and important to learn how SCE operates its grid.
- Our past collaboration on DOE VADER project has a solid foundation.

- Our method does not require system topology or state estimation.
- We can provide highly accurate outage detection and identification, with increasing DERs in SCE.
- Islanding could be passive and we can detect different cases, where traditional voltage except can fail.
- We provide theoretical guarantees based on time series data only.