L6 ENGM031

Smart Grids: Data and Digitised Distribution Networks

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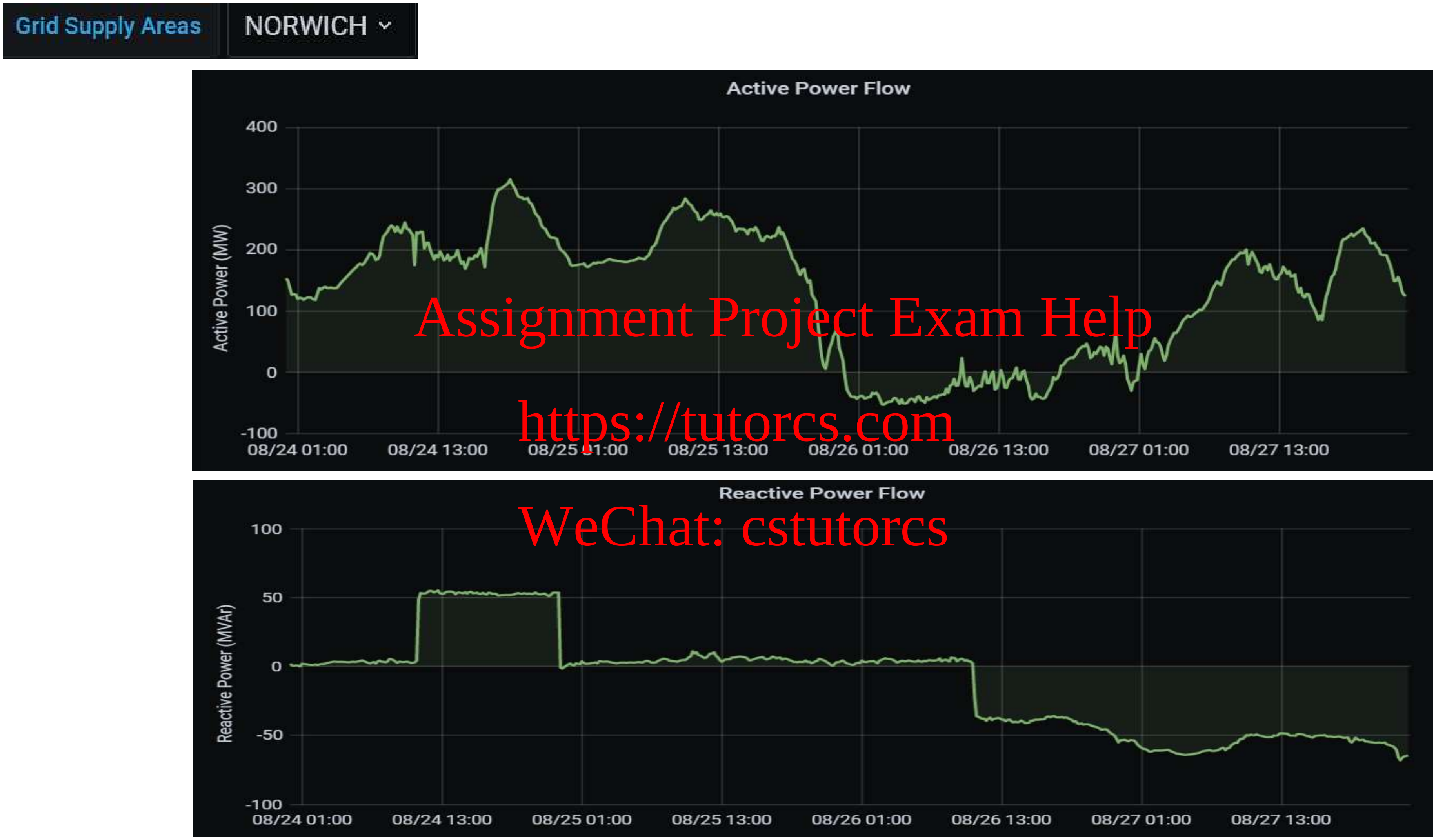


Grid Supply Areas
NORWICH
Active Power Flow
Active Power (MW)
400
300
200
100
0
-100
08/24 01:00
08/24 13:00
08/25 01:00
08/25 13:00
08/26 01:00
08/26 13:00
08/27 01:00
08/27 13:00
Reactive Power Flow
Reactive Power (MVAr)
100
50
0
-50
-100
08/24 01:00
08/24 13:00
08/25 01:00
08/25 13:00
08/26 01:00
08/26 13:00
08/27 01:00
08/27 13:00

Smart Grids: The Age of Data

*IEEE Electrification Magazine / **MARCH 2021***

- In power grids, data is essential for situational awareness, modelling, protection, and control.
  - US Dept. of Energy define situational awareness as “understanding current environment and being able to accurately anticipate future problems to enable effective actions”
- Adoption of phasor measurement units (PMUs) and smart meters makes remote measurements available for access via communication networks.

We are building a modern, digitised energy system designed for a low carbon world. To meet the challenge we are making our operational data open, available and transparent. Together, we can use data to unlock benefits for all.

UK Power Networks
Delivering your electricity

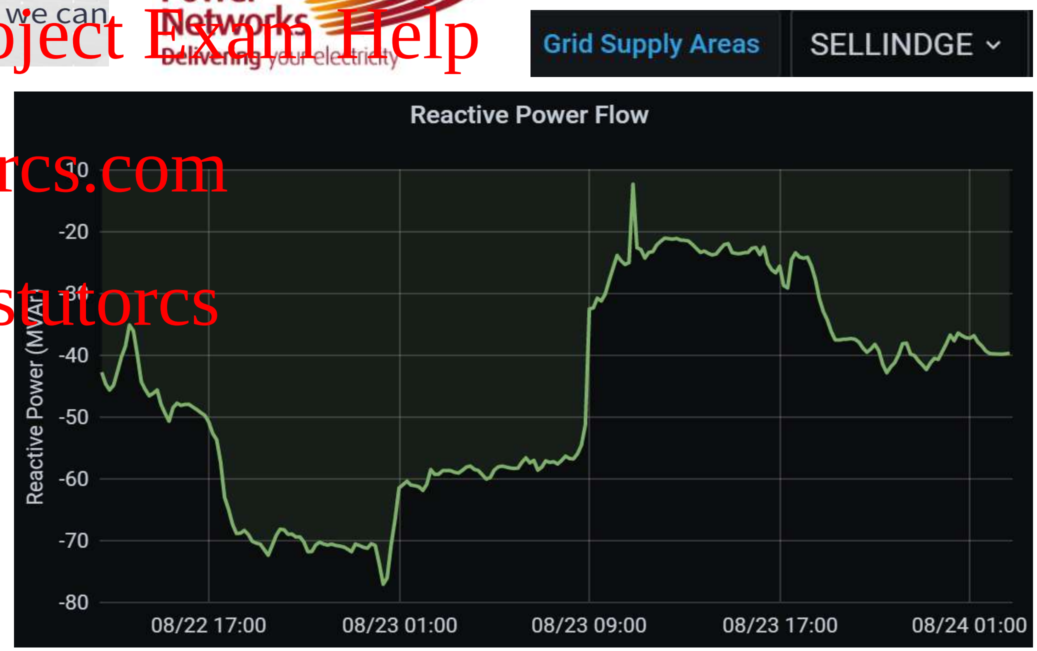
Network Data

Coming Soon:

- Load Profiles
- Current Planned Outages
- Fault History
- Fleet and Generator Data

- Current Power Outages
  Open Data
- Piclo
  Open Data
- Flexibility Services
  Open Data
- Embedded Capacity Register
  Open Data
- Long Term Development Statement (LTDS)
  Open Data
- Design Specification (G81) library
  Open Data
- Losses Information
  Open Data
- Asset Locations
  Open Data

Facilitating Net Zero | Strategy & Innovation | DSO Dashboard



What are the security implications of open operational data?

Data-Driven Engineering: Reliability & Resilience of North American Bulk Power System

- Distributed energy resources (DERs), aggregators and the Internet of Things are pushing consumers of electric energy toward becoming prosumers in our electrical ecosystem.

- Persistent threat of cyberattacks on the electrical infrastructure by cybercriminals and nation–states is bringing attention to securing the Bulk Power System (BPS).

- Challenges are significant, yet how we overcome them may be more straightforward: Collaboration is key, information sharing is critical, technology innovation is inevitable, and engineering decisions require adequate data to develop appropriate solutions.

- Consider the concept of data-driven engineering, where real-time and offline engineering decisions are governed by applications and tools that consume and use information.

- North American Electric Reliability Corporation (NERC) are focusing on ways to ensure BPS reliability and resilience using risk-informed mitigation strategies.

  - includes gathering information regarding the extent of conditions, performing engineering analyses of available information, and developing recommendations for identified risks.
  - framework can be applied to offline engineering decisions, real-time applications and operating procedures, and strategies for securing the North American BPS as one of the largest cyberphysical systems in the world.

- Article provides brief examples of how data and information exchanges can enhance BPS reliability and resilience.

Edited extracts from article by Ryan D. Quint (Ryan.Quint@nerc.net) North American Electric Reliability Corporation in IEEE Electrification Magazine March 2021

Reliability & Resilience of North American Bulk Power System:
Using Synchronized Measurement Data to Mitigate Oscillation Events

- On 11 January 2019, a steam turbine at a combined-cycle power plant in Florida experienced a failed potential transformer connection that led to an erroneous voltage measurement in its turbine control system.

- Power–load imbalance controller perceived a mismatch between the mechanical input power and the electrical output power and exhibited cyclic ramping of the unit, with a period of 4 s.

- Forced oscillation near 0.25 Hz interacted with the primary natural mode of the Eastern Interconnection (EI) of North America, causing large inter-area power swings and frequency oscillations that were observed by all reliability coordinators (RCs) across the EI (see Figure 1).

- Abnormal grid conditions were picked up using phasor measurement unit (PMU) data and even conventional supervisory control and data acquisition (SCADA) information.

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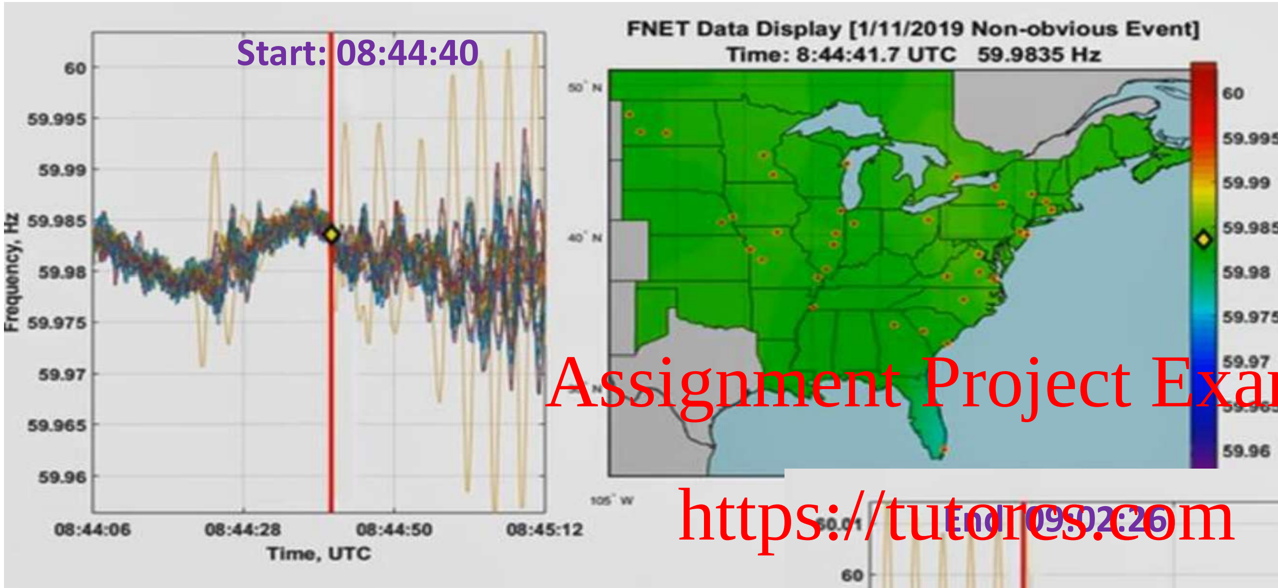
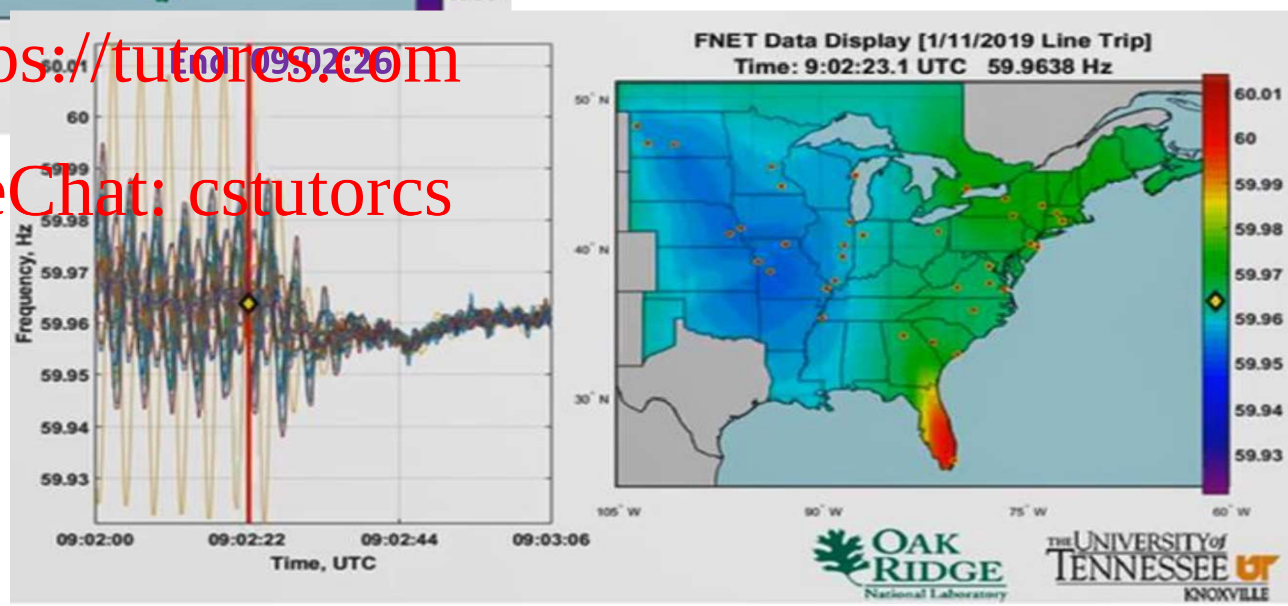
Time Line of 11-01-2019 Disturbance on Eastern Interconnection USA:



As the oscillation evolved to an interconnection-wide oscillation, several Reliability Co-ordinators (RCs) and Transmission Operators (TOPs) detected the oscillation, some using advanced oscillation tools that utilize PMU data, others relied on SCADA or phone calls from generators .

Generating units oscillated in response to their terminal frequency and voltage, and several units were removed from automatic generation control (AGC) to try to fix the perceived oscillation or prevent damage to the units.



Reliability & Resilience of North American Bulk Power System:
Using Synchronized Measurement Data to Mitigate Oscillation Events

- For the 11 January incident, the source of the oscillation was removed from the system by the local plant operator, which took actions to shut down the facility following identification of inadvertent intercept valve operations due to the failure.
- High-speed, time-synchronized data picked up this disturbance as it transpired, but RCs lacked real-time capabilities to identify the source and take coordinate action.
- Essentially, the oscillation event was captured in real-time, operators were limited in their tools and capabilities, and, therefore, the oscillation persisted for more than 18 min until the local operator removed the facility.
- Ultimately, the persistent oscillation led to equipment damage at the generating facility that required weeks to fix, leading to degraded reliability and significant expense for the owner.
- So where can we improve? The data are available, but we need better sharing, a concerted effort to develop tools using interconnection-wide information, and coordinated operating procedures for managing wide-area disturbances.

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Reliability & Resilience of North American Bulk Power System:
Using High-Resolution Data to Understand Inverter-Based Resource Performance

- Western Interconnection in North America has observed multiple fault events where solar PV resources exhibited abnormal performance and reduced power output on a wide scale.

- Some of these events, such as the Blue Cut Fire, Canyon 2 Fire, Palmdale Roost, Angeles Forest, and San Fernando disturbances, have gained notoriety due to the breadth of solar PV tripping and the cessation of current injection (a response referred to as *momentary cessation*) and the adverse impacts this performance has on the BPS.

- NERC and Western Electricity Coordinating Council have led disturbance analyses to identify root causes of reductions in solar PV output and to recommend mitigating actions.
  - root cause analysis is predicated on the availability of sufficient information to draw useful conclusions.

- SCADA data can help provide indications of performance (i.e., tripping versus momentary cessation) but often fall short in understanding why a resource behaved the way it did.
  - Whilst a plant may enter momentary cessation and recover to pre-disturbance conditions in tens/hundreds of seconds, it does not help understand causes & effects of their behaviour.

- Similarly, a plant that has inverters tripping on a phase-locked loop loss of synchronism, but cannot provide high-speed data from the disturbance does not yield sufficient information.

- When data is available and the NERC, the affected plant owners, and related equipment manufacturers are all able to identify the reasons for tripping, it is possible to improve BPS reliability and mitigate future potential reliability issues.

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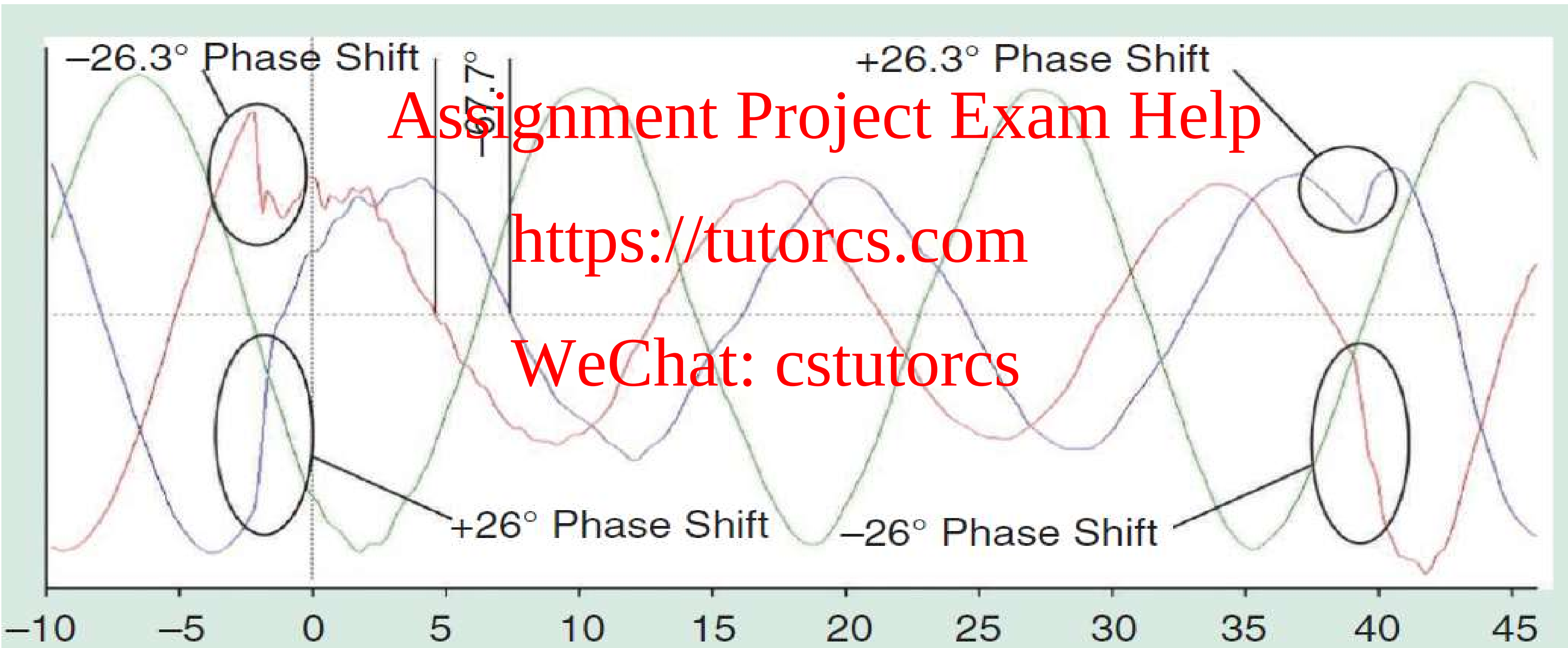
- In the August 2016 Blue Cut Fire disturbance, multiple solar PV inverters tripped on a perceived “low-frequency” event that was ultimately caused by a phase angle shift in the measured terminal voltage phasor (see Figure 2).



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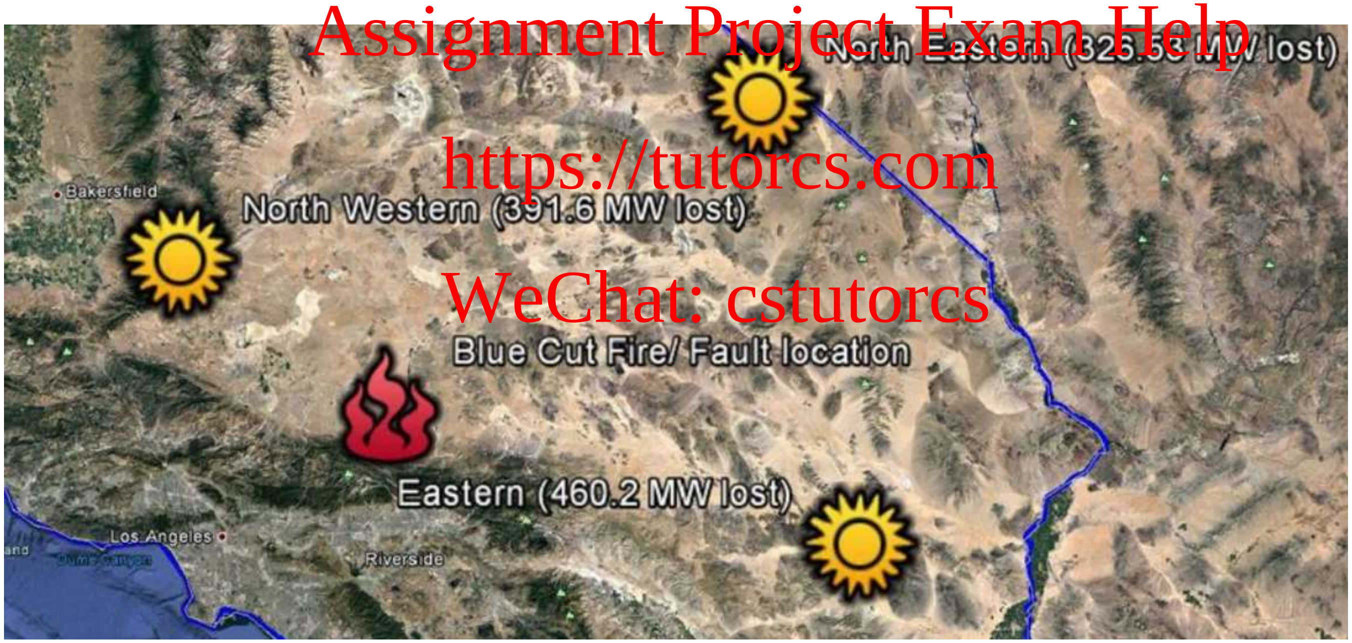
Reliability & Resilience of North American Bulk Power System:
Using High-Resolution Data to Understand Inverter-Based Resource Performance

- On August 16, 2016, at 10:36 a.m. Pacific, the Blue Cut fire began in the Cajon Pass, just east of Interstate 15.
- Fire quickly raced toward an important transmission corridor that comprises three 500 kV lines owned by Southern California Edison (SCE), and two 287 kV lines owned by Los Angeles Department of Water and Power (LADWP).
- By the end of the day, the SCE transmission system experienced thirteen 500 kV line faults and the LADWP system experienced two 287 kV faults as a result of the fire. Four of these fault events resulted in the loss of a significant amount of solar PV generation..



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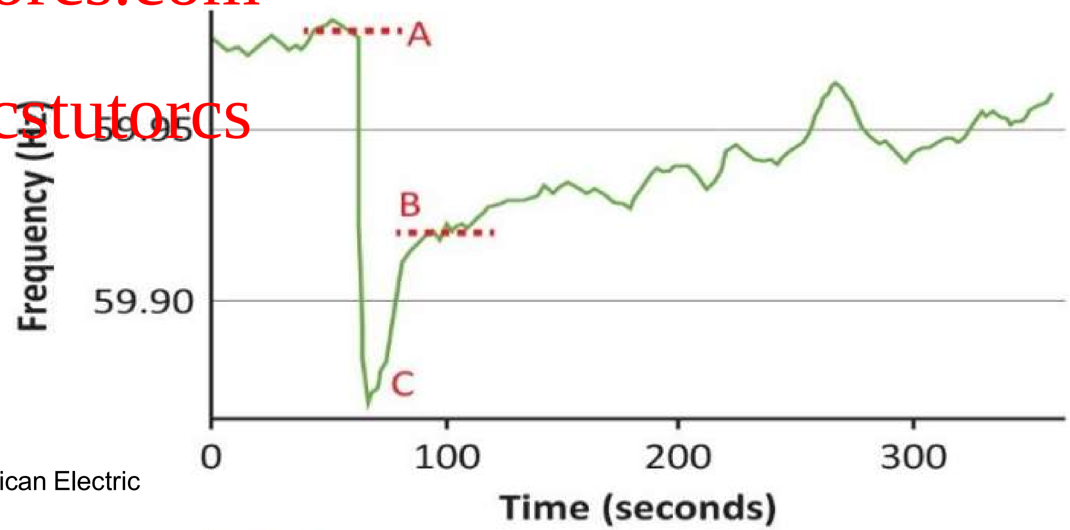
- Most significant event, occurred at 11:45 a.m. Pacific, resulted in the loss of nearly 1,200 MW of solar PV generation.
- This value was determined by SCE's supervisory control and data acquisition (SCADA) system, which has a sampling rate of approximately 1 sample/4 seconds.
- It is possible that there was a larger loss of resources that was not captured due to the SCADA sampling rate.
- There were no solar PV facilities de-energized as a direct consequence of the fault event; rather, the facilities ceased output as a response to the fault on the system.
- SCE analyzed the net load response and determined that no noticeable amount of distributed energy resources (DERs) tripped due to the fault on the BPS; this analysis focused solely on the solar PV generation connected to the BPS..

Western Interconnection frequency reached its lowest point of 59.867 Hz. Frequency recovered about seven minutes (420 seconds) later (not shown).



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- All of the line faults caused by the fire cleared normally with roughly the same fault clearing time and fault magnitude. Of the 15 faults, four caused a loss of PV generation as shown in Table 1.1.
- Event No. 1 was particularly impactful because of the widespread loss of 1,178 MW of PV generation. Approximately 66 percent of the generation lost in that event recovered within about five minutes. Three PV plants had a sustained loss of 400 MW that did not return until the following day, reportedly due to curtailment orders from the BA

Table 1.1: Solar Photovoltaic Generation Loss

Event No.	Date/Time	Fault Location	Fault Type	Clearing Time (cycles)	Lost Generation (MW)	Geographic Impact
1	8/16/2016 11:45	500 kV line	Line to Line (AB)	2.49	1,178	Widespread
2	8/16/2016 14:04	500 kV line	Line to Ground (AG)	2.93	234	Somewhat Localized
3	8/16/2016 15:13	500 kV line	Line to Ground (AG)	3.45	311	Widespread
4	8/16/2016 15:19	500 kV line	Line to Ground (AG)	3.05	30	Localized

- From a GB perspective, something similar would occur if an extreme storm resulting from climate change moved across Northern England tripping first the double circuit line on the west and then the double circuit line on East, especially if immediately prior significant wind generation was available in Scotland.
- A similar situation could occur with a cyber attack on two carefully selected substations.

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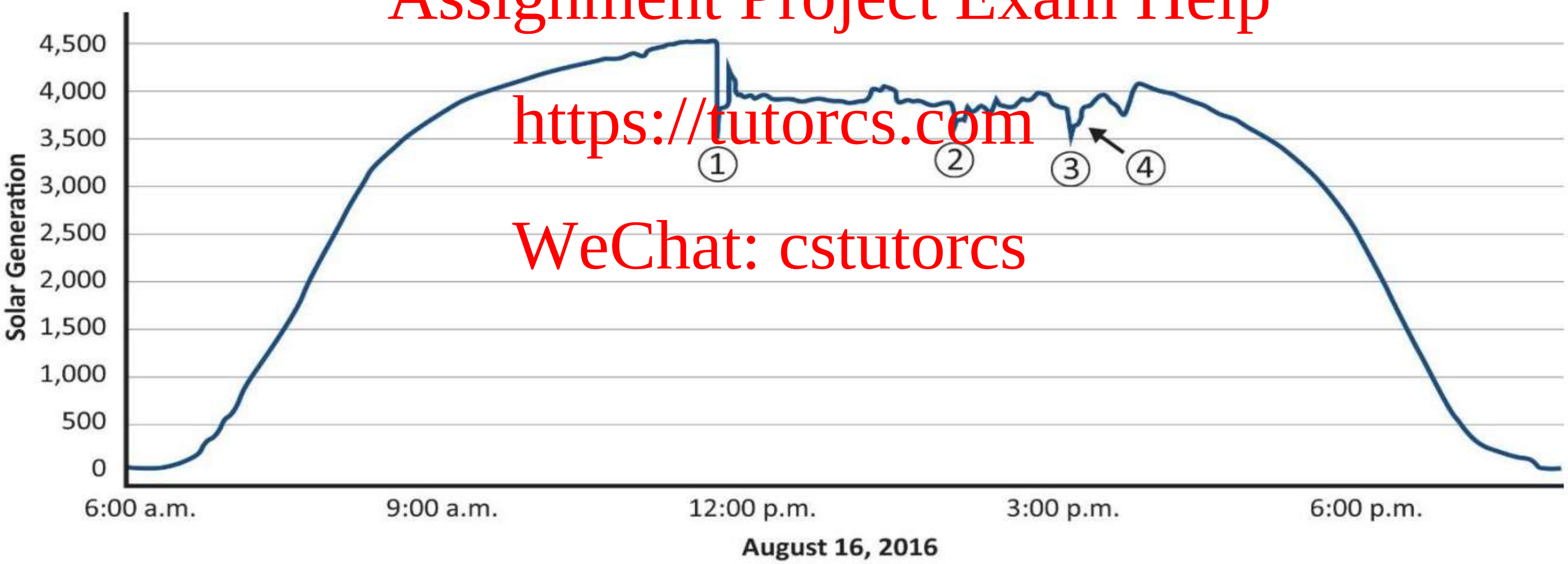
- Figure shows the reduction in solar output for the four events on August 16.
- Solar production did not return to pre-disturbance level after the 11:45 Pacific event; this was because three PV plants had 400 MW of curtailments issued to them.
- Subsequent three events may have had greater resource loss if initial curtailments had not been activated.

Utility-Scale Solar PV Output in SCE Footprint on August 16, 2016



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- August 16 event raised issue of inverter disconnects during faults.
- Once aware of problem, SCE/CAISO discovered it was not isolated incident.
- SCE/CAISO determined this type of inverter disconnect occurred 11 times between Aug 16, 2016, and Feb 6, 2017:

Table 1.2: Fault Event Information

Event No.	Date/Time	Fault Location	Fault Type	Clearing Time (cycles)	Lost Generation (MW)	Geographic Impact
1	08/16/2016 11:45	500 kV line	Line to Line (AB)	2.49	1,178	Widespread
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3	08/16/2016 15:13	500 kV line	Line to Ground (AG)	3.45	311	Widespread
4	08/16/2016 15:19	500 kV line	Line to Ground (AG)	3.05	30	Localized
5	09/06/2016 13:17	220 kV line	Line to Ground (AG)	2.5	490	Localized
6	09/12/2016 17:40	500 kV line	Line to Ground (BG)	3.04	62	Localized
7	11/12/2016 10:00	500 kV CB	Line to Ground (CG)	2.05	231	Widespread
8	02/06/2017 12:13	500 kV line	Line to Ground (BG)	2.97	319	Widespread
9	02/06/2017 12:31	500 kV line	Line to Ground (BG)	3.01	38	Localized
10	02/06/2017 13:03	500 kV line	Line to Ground (BG)	3.00	543	Widespread
11	05/10/2017 10:13	500 kV line	unknown	unknown	579	Somewhat Localized

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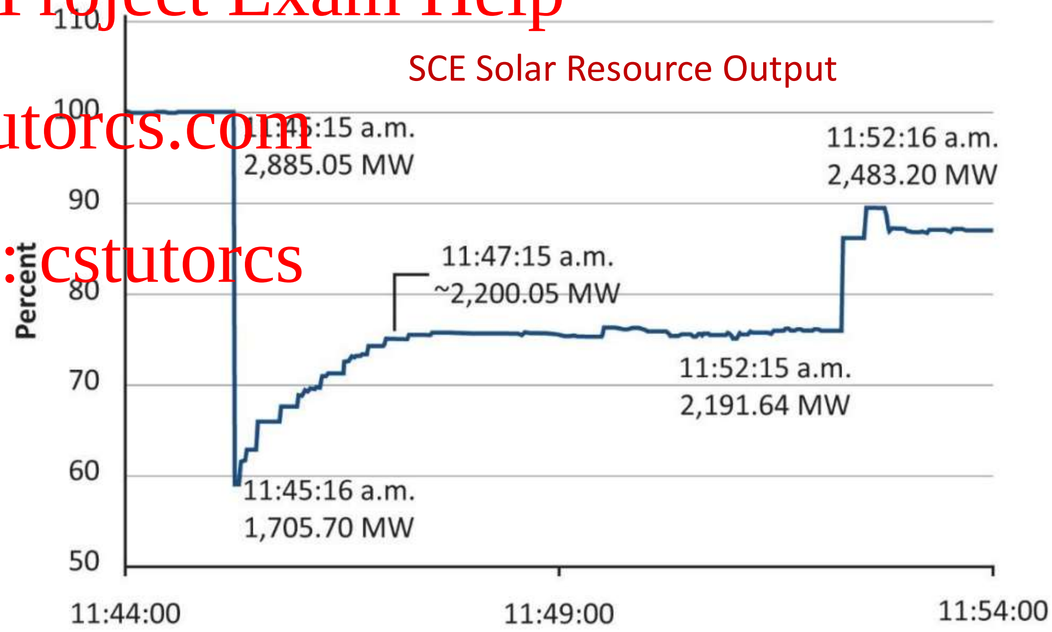
- Largest percentage of generation loss (~700MW) was attributed to a perceived, though incorrect, low system that the inverters responded to by "tripping".
  - Perceived low frequency was due to a distorted voltage waveform caused by the transients generated by the transmission line fault.
  - Inverters were configured to trip in 10 milliseconds for frequencies less than or equal to 57 Hz.

- Second largest loss (~450MW) was caused by inverter momentary cessation due to system voltage reaching the low voltage ride-through setting of the inverters.
- Third largest loss (~100MW) was tripped by inverter dc overcurrent protection after starting the momentary cessation operation. Cause of these inverters tripping has not been determined and is still under investigation.

– Momentary cessation is when the inverter control ceases to inject current into the grid while the voltage is outside the continuous operating voltage range of the inverter. Inverter remains connected to the grid but temporarily suspends current injection.
– When system voltage returns to normal, inverter resumes current injection after a short delay.
– In Aug 16 event, many inverters momentarily ceased current injection.
– Time to return to pre-disturbance values (restoration of output) was a ramp of approximately two minutes.



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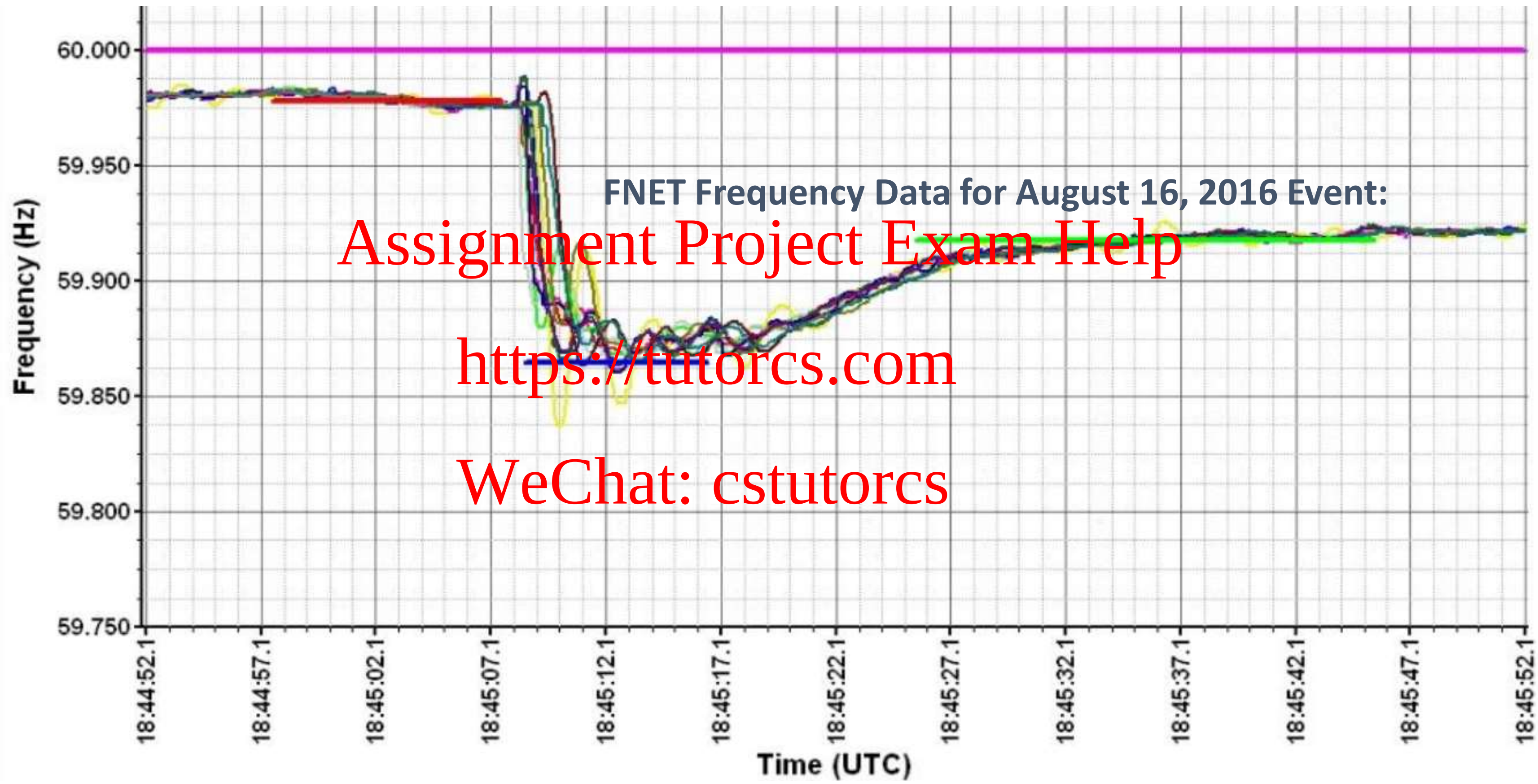

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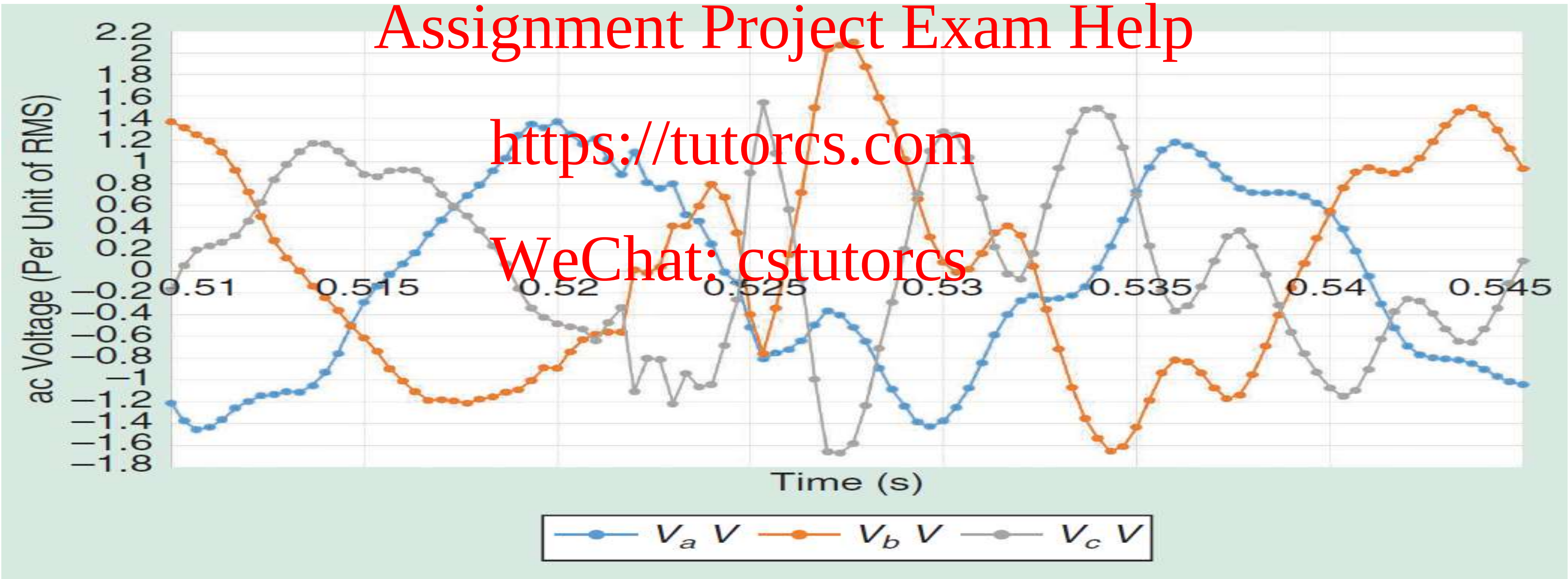
- In October 2017 Canyon 2 Fire event, a number of solar PV facilities tripped on a subcycle ac overvoltage that occurred at the inverter terminals.
- Instantaneous terminal voltage measurements were used against a trip setting, issue discussed in NERC Reliability Standard PRC-024, but this recommends use of filtered “rms” measurements rather than instantaneous ones.
- Led to updates in NERC PRC-024 and focus of IEEE Standard Project 2800 on interconnection capability & performance criteria for BPS-connected inverter-based resources.



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NERC published "Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources" in September 2019, including a section on data recording and real-time monitoring.

- TOs are strongly encouraged to ensure their interconnection requirements explicitly cover monitoring equipment and can adequately capture the following:
  - high-resolution, point-on-wave data at the point of interconnection, capturing the overall plant performance related to BPS disturbances
  - continuously recorded synchronized phasor measurement data capturing active & reactive current (and power), phase & positive sequence voltages, and busbar frequencies
  - high-resolution, point-on-wave oscillography data on the ac and dc sides of inverters to better understand their behaviour during large disturbances
  - sequence-of-events data from all elements within a plant, including inverter fault codes and changes in status, time-synchronized with a resolution of 1 ms.
- Ability to perform post-mortem forensic analysis on the performance of inverter-based resources hinges on availability of appropriate data.
- Without data, industry will not understand the interactions of power electronics with the bulk grid.
- Simulation studies cannot truly replace real-world experience with actual monitoring equipment installed in the field.

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Reliability & Resilience of North American Bulk Power System: Data Transfer Across a Transmission–Distribution Interface With Increasing DERs

- With the rapid pace of DER interconnection, information exchanges across the transmission–distribution (T–D) interface are now more important.
- Grid operators are faced with ensuring BPS reliability and resilience, whilst numerous resources are located on the distribution system with no visibility to transmission utilities.
- As the generation mix moves toward more distribution-centric resources, BPS grid operators are challenged with using the resources and services they have available to balance generation and demand, manage BPS voltage profiles, and ensure BPS stability and security.
- While net loading may be sufficient at low DER penetration levels, lack of information exchanged across T–D interface poses challenges to BPS grid operators and planners.
- DERs behave with a different steady-state profile and dynamic response characteristic than end-use loads.
- Resource adequacy studies need to consider the variability of renewable energy to ensure planners have adequate availability of capacity and energy to always meet demand.
- Grid stability planners must consider the abnormal behaviour and tripping of DERs during BPS fault events; observed in multiple instances in southern California.
- Transmission energy management systems need access to information, at a quality/detail level significantly greater than net quantities normally captured at the T–D interface.

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Reliability & Resilience of North American Bulk Power System:
Reliability Guideline: DER Data Collection for Modeling in Transmission Planning

- NERC recently published "Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies," providing utilities with recommended practices for gathering data used for developing planning models that include DERs.
- Guideline intended to bridge the barriers between distribution utilities, with limited data from DER interconnections, and transmission planners who need information to populate aggregate DER representations in power flow and dynamic simulations.
- With limited information about forecast capacity level of DERs, the type and vintage of DERs, and interconnection requirements, transmission planners often make engineering judgments to develop DER models in planning assessments.
- Information about currently installed & projected future DER installations is critical in developing an understanding from which sensitivity studies can be performed.
- Without data to populate models for performing simulations, utilities are unable to determine the level of impact DERs have on their systems.
- Utilities should not presuppose impacts to drive the need for data collection; rather, the data should be available to drive the identification of potential impacts and deliver appropriate solutions to mitigate future reliability issues.

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Reliability & Resilience of North American Bulk Power System:
Reliability Guideline: DER Data Collection for Modeling in Transmission Planning

TABLE 1. Examples of solutions to DER impacts.

DER Impact	Possible Solution Options
Variability and ramping challenges	• Making modifications to balancing requirements, such as levels of spinning and contingency reserves • Ensuring flexible resources to meet daily ramping needs • Incorporating DERs into BPS economic dispatch and unit commitment
Lack of visibility and control by grid operators	• Development of DER aggregators and management systems • Development of new market products and services • Ensuring sufficient flexible resources and reserves to manage increasing uncertainty • Coordination across the T–D system interface
Diminished local, inter-area, and regional transfer capability	• Improvements to modeling and study techniques to ensure reliable operation in a much more variable and uncertain environment • New tools and techniques to determine operating limits in real time • Updates to outage schedules and operating plans
Angular instability	• Identification of must-run resources, adequate levels of system strength, and operating limits to ensure system stability
Frequency instability and increasing rate of change of frequency	• Determination of critical inertia levels and enforcement of those levels during real-time operation • Ensuring sufficient (carrying additional) frequency-responsive reserves and fast frequency response capability • Improvements to frequency response obligation and/or measures
Reduction in steady-state and transient voltage stability	• Must-run BPS resources to meet local voltage stability requirements • New transmission-connected dynamic reactive elements to support BPS voltage variability • Modifications to reactive reserve and reactive stability studies
DER tripping and cascading outage risks	• Carrying extra reserves to ensure that loss of additional or unexpected generating resources does not result in cascading events • Transmission reinforcements and operating limits to avoid adverse impacts to BPS performance

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Reliability & Resilience of North American Bulk Power System:
The North American BPS: A Cyber-physical System

- Connection between information technology and operational technology networks is expanding, widening potential attack surfaces where vulnerabilities could lead to compromised industrial control systems on the BPS.
- High-resolution data from state-of-the-art sensors and measurement devices installed in the field are sent across communications networks to control centers for use in real-time advanced applications and offline engineering functions.
- Data quality, integrity, and security are of utmost importance for processes that control and operate the BPS.
- Therefore, security personnel are deploying analytics and tools to detect, analyze, and respond to security threats.
- Applications can also ensure data integrity by applying quality checks and using metadata to ensure that accurate information is provided to system operators. Metadata is data about data. In other words, it's information that's used to describe the data that's contained in something like a web page, document, or file. Another way to think of metadata is as a short explanation or summary of what the data is.
- Data analytics can improve offline engineering programs to detect bad, corrupted, skewed, and absent information to ensure appropriate decisions are being made.
- In a world driven by information, security is of paramount importance.

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Learning-Enabled Residential Demand Response

Automation & security of cyber-physical Demand Response systems.

- RESIDENTIAL DEMAND RESPONSE (DR) programs have been validated as a technology to improve energy efficiency and electric power distribution reliability.
  - but technical & organizational challenges hinder their techno-economic potential.
- In practice, these challenges are related to the small-scale, distributed, heterogeneous, and stochastic nature of residential DR resources.
  - Article investigated online and reinforcement learning methods capable of overcoming these challenges in the context of DR pricing, scheduling and cybersecurity.
- Distribution grids are undergoing a rapid overhaul due to the massive deployment and expansion of distributed energy resources (DERs).
- DER Rollout also imposes additional operational challenges, bidirectional power flows & voltage fluctuations etc, and, as a result, additional wear-and-tear on electric power equipment.
- **DR is a technology that can provide additional flexibility by organizing adaptable residential, industrial, and commercial loads to provide a broad range of distribution-level ancillary services** (e.g., energy arbitrage, peak shaving, balancing regulation, congestion relief, capacity deferral, and voltage support).

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Learning-Enabled Residential Demand Response

Automation and security of cyber-physical demand response systems.

- Established DR programs mainly target commercial and industrial loads that are relatively homogeneous in size and technical capabilities.
- Thus, they provide economy-of-scale benefits, which in turn allow for intuitive pricing and standardized interfacing with energy management systems used by utilities.
- Residential-scale DR resources may have a significant potential of providing system-beneficial services, but they are challenging to employ due to their heterogeneous characteristics and electricity usage patterns and preferences.
- In 2018 New York City's Consolidated Edison (ConEd) launched the SmartAC program that allowed for a reduction of the power consumption of residential air-conditioners (ACs) during peak hours in exchange for retail gift cards..
  - Program used IoT device with a smartphone app to deliver control signals to participating AC units, also provided an opportunity for DR customers to override this signal.
  - However, despite initial success, SmartAC was discontinued in May 2020 for undisclosed reasons.
  - Public materials indicate that the reasons may include overly intrusive control actions, unreliable IoT devices and smartphone apps from third-party providers, and gaming opportunities to receive incentive payments without providing any effective load reduction.

DR Forum Agenda

- Commercial Demand Response Programs
- Competitive Procurement Plan
- Rider R Participation
- Gas Demand Response Pilot
- Residential Demand Response Program (BYOT)
- Commercial & Industrial (C&I) Programs
- Advanced Metering Infrastructure (AMI) Project Update
- Green Button Connect
- Demand Response Management Systems

conEdison

ConEd still offer numerous demand response programmes, many designed for industrial/commercial customers, but some directed to residential demand.

Learning-Enabled Residential Demand Response

Pacific Gas & Electric (PG&E) SmartAC demand response programme.

- SmartAC program is voluntary and there's no penalty for non-participation.
- On hot summer days when demand increases because thousands of customers are using their air conditioning units, PG&E may remotely activate SmartAC devices in order to help maintain adequate power supplies and avoid power interruptions. This is called an "event".
  - SmartAC device is activated only from May 1 through October 31.
  - SmartAC Events Days can be as short as an hour and no more than six hours in a day.

Take advantage of a win-win opportunity

When you sign up for the PG&E SmartAC program, we install a free SmartAC device on your air conditioner (AC) and give you $50 for participating. In case of an energy shortage from May 1 - October 31, we send a signal to your SmartAC device directing your AC to run at a lower capacity. Understand how the program works.

Sit back and relax

The SmartAC device automatically does all the work. There's nothing you need to remember. If a SmartAC event is called at a time that's inconvenient for you, you can easily return your AC to its normal settings. You can also receive Event Day notifications on your smartphone via IFTTT.

- For $50 or gift cards, would you agree for your air-conditioning to be turned off on a very hot day?
  - OK for an hour, home temperatures probably only increase a few degrees, but 6-hours.
  - Smart "Gaming" customers with energy efficient homes, could over-chill homes at night and allow AC to hold a lower than normal temperature, until SmartAC switches off AC.
- Is society ready to help others, by allowing a DNO to turn off your domestic heating/cooling when ambient temperature is low/high?
- Would you prefer to join a DR programme or pay for investment in Grid infrastructure?
  - Depends…. at present your DNO charges your energy supplier about ¼ of a £500/year electricity bill.
  - If they raised this from £125 to £175, i.e. your bill increased to £550, would you sign-up for DR?

PG&E Demand Response Programmes:

- PG&E's demand response programs enable customers to reduce energy use during periods of peak demand, which provides grid stability, lowers costs for customers and realizes greenhouse gas emissions reductions.
- SmartAC still being publicised BY PG&E in August 2021, hence assume still available.
- Approximately 160,000 residential customers participate in the PG&E SmartRate & SmartAC DR programs:

Program	Description	2020 Results
SmartRate	Gives residential customers a discount on regular summer electricity rates in exchange for higher prices during 9 to 15 SmartDays per year, typically occurring on the hottest days of the summer.	Approximately 65,000 customers participated in SmartRate and provided an average load reduction of nearly 12 megawatts (MW) per event day.
SmartAC	Allows PG&E to send a signal to a PG&E-provided device on a customer's air conditioner, cycling the air conditioner to use less energy. The program is offered May through October.	Approximately 90,000 participants provided about 40 MW of potential load reduction, which was bid into the California Independent System Operator (CAISO) wholesale market as a Proxy Demand Resource but can also be called on for emergencies and near-emergency purposes by the CAISO or PG&E's grid and system operators.

SmartRate: typical customer delivered average load reduction of 180W on a "DR event" day.
SmartAC: typical participant delivered average load reduction of 450W on a "DR event" day
Guess: After Diversity Maximum Demand for typical residential customer in California ≈ 4kW, hence 450W for SmartAC sounds good, but needs more participants

Learning-Enabled Residential Demand Response

Automation and security of cyber-physical demand response systems.

- Article discusses current residential DR systems in the context of existing infrastructure and realistically envisioned future development.
- Ongoing massive rollout of smart meters (SMs) and recent advances in (open source) communication protocols tailored toward DR systems pave a way to aggregating residential DR resources into more efficient and more homogeneous controllable ensembles.
- Emerging data mining and machine learning (ML) techniques further support the decision-making processes of the utility or third-party aggregators to determine optimal DR incentive schemes and to control actions that trade off between the utility and DR customer perspectives.
- At the same time, while novel ML approaches can reduce data and communication requirements, coupling power system operation with a broad spectrum of new communication and control infrastructure requires a critical cybersecurity assessment.

Edited extracts from article by Ryan D. Quint (Ryan.Quint@nerc.net) North American Electric Reliability Corporation in IEEE Electrification Magazine March 2021

Learning-Enabled Residential Demand Response

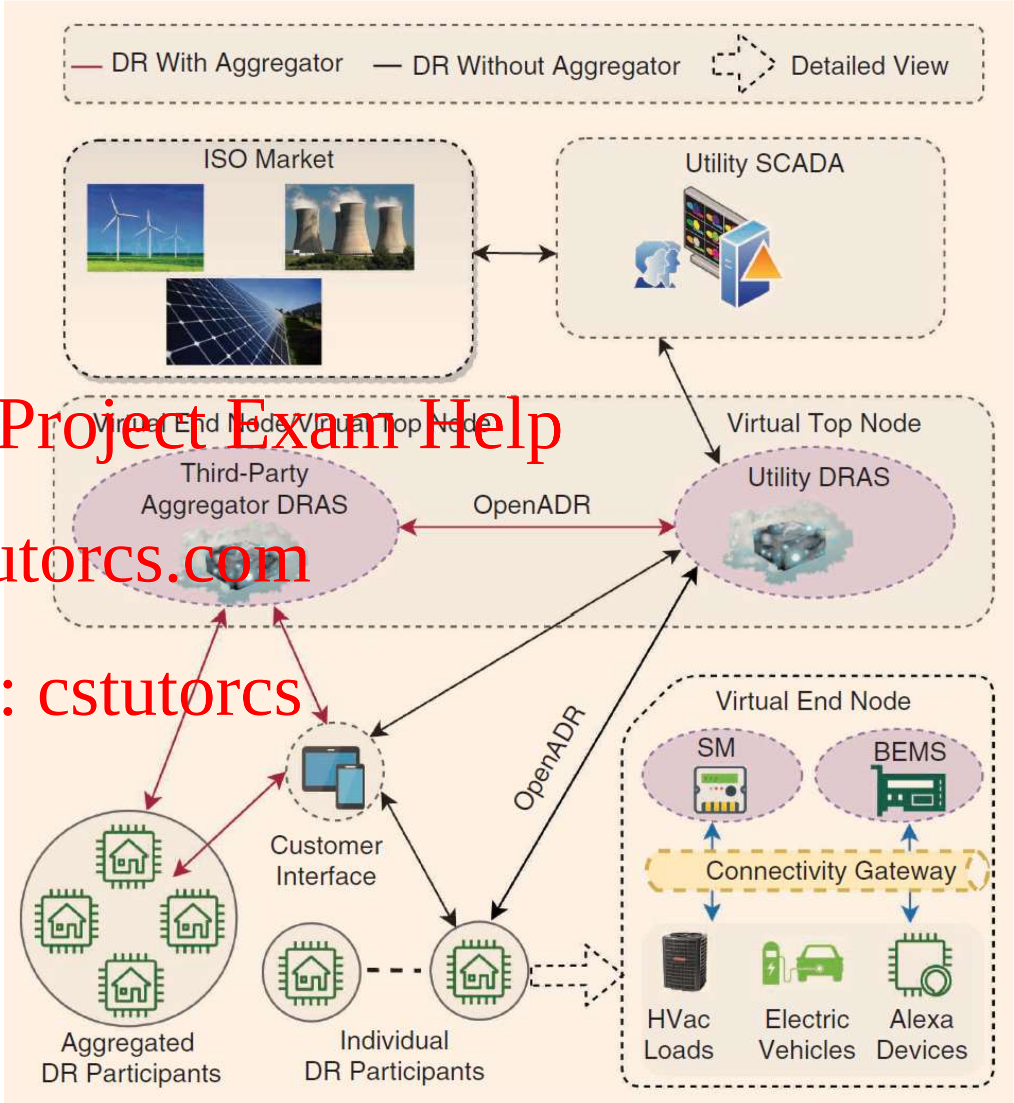
Cyber-physical demand response systems.

- With advances in communication technologies and artificial intelligence, power utilities and third-party aggregators have been increasingly automating DR routines.
- This automation extends the cyberspace of electricity consumers and connects it with the cyberspace of the utility.
- This section provides an overview of cyberphysical nexus among customers, third-party aggregators, and utilities.

Edited extracts from article by Ryan D. Quint (Ryan.Quint@nerc.net) North American Electric Reliability Corporation in IEEE Electrification Magazine March 2021

Learning-Enabled Residential DR: Cyber-physical DR systems.

- Figure summarizes typical architecture of U.S. residential DR programs.
- Power utilities communicate with DR resources, such as thermostatically controlled loads (TCLs) and EVs, either directly or via third-party aggregators.



DRAS: DR automated server;
SCADA: supervisory control and data acquisition;
ISO: independent system operator;
BEMS: building energy-management system;
HVAC: heating, ventilation, and air-conditioning;
ADR: automated DR.

Edited extracts from article by By Robert Mieth, Samrat Acharya, Ali Hassan, and Yury Dvorkin i*n IEEE Electrification Magazine March 2021*

Learning-Enabled Residential Demand Response

Automation and security of cyber-physical demand response systems.

Utility employs a DR automated server (DRAS), which functions in three stages:

- *Data acquisition stage*:
  - Server acquires the operation schedules of ISO market, captured by centralized SCADA system via wide-area network (WAN) using cellular networks or power line communication.
  - Server acquires real-time energy usage of DR resources logged by distributed SMs via WAN with WiMAX and cellular networks.
- *DR scheduling stage*:

  - Server evaluates time, duration & incentives to procure needed DR, using data from ISO and DR resources.
  - Power grid utilities and aggregators have started employing Machine Learning techniques to schedule DR.

  - For example, 20 aggregators in California use artificial intelligence to optimize DR profit.
  - After scheduling DR, server broadcasts DR incentives and schedules to customers enrolled in DR program via user interfaces, such as smartphone apps and in-home BEMS.

  - Customers accept (opt-in) or reject (opt-out) the offered DR schedules and send their selected choices back to the DRAS.
  - Customers make opt-in/out decision either automatically, using BEMS, or manually, via smartphone apps.
- *DR monitoring and control stage:*
  - Once the DR schedule is accepted by the customers, the DRAS monitors and controls the operation of the participating DR resources.
  - Notably, due to the remote control features of IoT enabled by smart home appliances, e.g., Alexa, GoogleNest, EVs, and HVAC loads, the customers can disengage its DR resources at any time, even during the DR event.

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Learning-Enabled Residential Demand Response

Automation and security of cyber-physical demand response systems.

Aggregation: important component of residential DR program.

- Aggregating individual residential DR resources based on their physical (location, type of appliance) or organizational (incentive scheme, timing) attributes as well as tuning necessary DR infrastructure makes it possible to design DR ensembles that allow for taking advantage of both the economy of scope and the economy of scale.

- Aggregation can be offered to the utility as a service from third-party providers, thus reducing utility-side organizational overhead and exposure to technical and financial risks.

- Aggregators can either aggregate customers to facilitate communication with the DRAS or to schedule, monitor, and control the DR resources by means of their own DRAS server, thus replacing the utility-end DRAS server.

- However, aggregators may not use same communication protocol as utility DRAS.
  - For instance, most utilities communicate with DR resources or aggregators via the OpenADR 2.0 specification, whereas the aggregators may use proprietary communication protocols.
  - OpenADR 2.0 communication protocol is a non-proprietary, OSI exchange model for DR applications, recently recognized as IEC 62746-10-1, as interface between DR participants and a utility or aggregator.

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Learning-Enabled Residential Demand Response: Challenges in residential DR programs:

Small-scale:

- Individual contribution of residential loads is determined by low-wattage consumer appliances (except EVs).
- As a result, effective DR programs require a large number of enrolled DR participants, which implies profits from deploying DR must be shared among a large number of participants.
- Profit, partially distributed as monetary incentives, might be inadequate to engage & retain DR participants.
- However, nonfinancial incentives, e.g., an awareness of environmental impacts and the potential to mitigate climate change, may convince more customers to enrol in DR programs.

Distributed connectivity:

- Distributed DR participants have various means of connectivity (e.g., cellular network, Wi-Fi, and Bluetooth) and levels of cyber-hygiene.
- This diversity in cyber-awareness incurs both explored and novel (zero-day) vulnerabilities.
- Furthermore, due to the distributed nature of DR customers, utilities may need to uneconomically expand their infrastructure and scope to capture a small DR flexibility.

Stochasticity:

- Residential DR is subject to systemic and behavioral uncertainty.
- First, residential DR participants are not obliged to follow DR call signals.
- Even if the operator is able to directly control appliances, customers are always able to manually interfere and override the DR control signals.
- Additionally, even if preferences have been communicated, aspects of real-time preferences might be unknown to DR participants due to limited rationality and changing weather.

Heterogeneity:

- Residential DR participants are heterogeneous in nature, with unique load profiles and different preferences and behaviours that complicate implementation and standardization of residential DR programs.

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Learning-Enabled Residential Demand Response: Learning Optimal DR Decisions:

Goal of a DR program is to produce control or incentive signals that achieve desirable change in system demand.

Ability to satisfy this goal depends on 3 attributes that characterize each DR resource, but are not exactly known to the DR operator:

- *Available capacity*: Commit and dispatch DR resources with respect to their spatio-temporal restrictions and for particular applications, e.g., peak-load shaving, mitigation of intermittent injections from wind and solar, or other ancillary services.
- *Cost*: Determine the short- and long-term costs of dispatching and enrolling DR resources, respectively, and weigh them against other dispatchable resources available to the system.
- *Reliability*: Evaluate the projected real-time effectiveness of the scheduled DR dispatch decisions and account for uncertainty caused by the random, intentional or unintentional, interference of DR customers.

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Learning-Enabled Residential Demand Response
Learning Optimal DR Decisions:

Available DR capacity depends on DR characteristics and individual preferences of users, i.e.:

- DR participation of an EV requires DR operator to know its state of charge, desirable time of readiness, and battery-specific characteristics.
- Thermal inertia of cooling/heating systems can be exploited to time shift power-consumption; but estimating kW-capacity that can be extracted from thermal inertia requires information about the technical characteristics of systems and temperature preferences of users.
- Some system settings can be obtained using a communication infrastructure and digitized appliance interfaces, but individual preferences or comfort zones are rarely observable.
- Acquiring, processing, and storing behavioral data involves effort for both the DR operator and participants, which may outweigh the benefits of the DR program.

DR participants expect remuneration in return for participation, i.e.:

- Compensation for lost service, due to need for change in consumption patterns during DR events.
- Incentive to purchase new controllable appliances or external controllers.
- DR operators normally establish remuneration scheme that incentivizes participation.
- Cost of total remuneration must be kept at a reasonable level to ensure profitability of DR program.

Reliability of DR depends on accuracy of DR capacity estimates and sufficiency of incentives:

- Scheduled load reductions may be insufficient if the called appliances are not operated as estimated, they fail to communicate with the DRAS, or DR participants suddenly opt out from the DR event.
- Such uncertain behaviour difficult to predict, which reduces effectiveness of DR programs.

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ML-enabled DR program.

- Figure outlines design of a virtual DR resource model used to plan a residential DR program and inform scheduling and incentive decisions.
- Data mining process collects available data from customer SMs and SCADA and external information (weather, temperature, day of the week, and holidays).
- Notably, set of available measurements may be imperfect or incomplete, and the resulting data uncertainty must be accounted for.
- Using processed data and additional historical data sets, suitable ML algorithms can estimate available aggregated DR capacity, cost, and reliability, while abstracting attributes of individual DR resources and computing schedules and incentives optimal for the DR operator.

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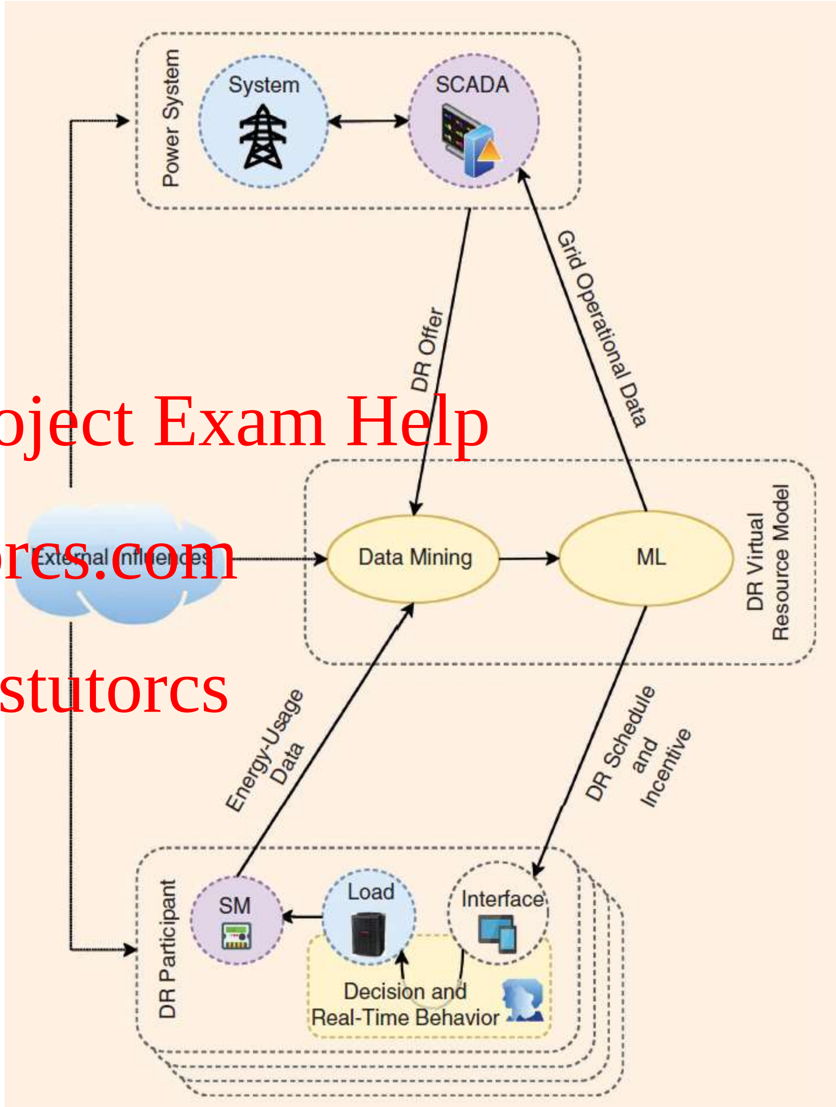

Learning-Enabled Residential Demand Response Security of DR Programs: Confidentiality

Confidentiality: refers to unauthorized acquisition and dissemination of information.

- Acquisition of granular data on customer-end energy usage via SMs is an integral part of the DR program.
- Energy-usage data can be leveraged by adversaries to reveal customer-end sensitive information and routines, e.g., house occupancy and wellbeing.
- Energy-usage data can also be breached at various stages of the DR: adversaries can exploit vulnerabilities in the SMs, communication channel between the utility/aggregator and customers, and DRAS server.
- Similarly, DR schedules sent by the utility/aggregator and the response of the customers to DR calls extends the attack surfaces of smartphones used for communication. For example, adversaries can compromise a smartphone application for DR programs and enable remote attacks.
- Smartphones are being used for remotely controlling residential IoT devices (e.g., controlling the room temperature via smart thermostats when not at home). This feature also increases an attack surface as smartphones, SMs, and other home IoT devices share the same trusted connectivity.

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Learning-Enabled Residential Demand Response
Security of DR Programs: Integrity

Integrity: indicates the unauthorized alteration or destruction of data or a process.

- Core of a DR program is a consensual exchange of DR schedules, SM data, and customer-end response to DR calls between the utility/aggregator and customers.
- DR schedules include DR incentives, time, duration, and capacity.
- Customer-end responses include accepting/rejecting DR calls or committing the DR capacity.
- Tampering with this information can have severe effects on effectiveness of DR program & power grid operation.
- False data injection attacks (FDIAs) on information sent to customers inherently forces them to make suboptimal decisions on how to use appliances.
- FDIAs on information sent to the utility/aggregator (e.g., accepting/rejecting the DR calls, SMs data) misinforms them and, hence, forces their DR scheduling routines and algorithm to produce erroneous dispatch decisions.
- These are considered as causative attacks on decision-support and learning schemes employed by the utility/aggregator.
- False DR schedules and customer-end responses can incur operational challenges, such as frequency and voltage excursions, and increase the system operating cost due to a mismatch between the committed DR capacity and the DR capacity provided in real time.

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Learning-Enabled Residential Demand Response
Security of DR Programs: Availability

Availability: implies authorized utility is deprived of reliable access to services & information.

- Effectiveness of DR programs relies on the uninterrupted and timely exchange of information between the utility/aggregator and customers.
- In turn, disrupting this information exchange by exploiting customer-end devices (such as SMs and smartphones), the communication channel between the utility/aggregator and customers, and the DRAS server can damage the efficacy of the DR program.
- For example, denial-of-service (DoS) attacks on SM data or on the responses of customers to DR calls can inject erroneous values into the training data used by the learning algorithm deployed by the utility/aggregator.
  - attack misleads the algorithm to design suboptimal DR schedules.
- Similarly, DoS attacks on DR schedules, DRAS servers, or VENs preclude DR customers from participating in DR calls.
- This undermines the trustworthiness of the DR program deployed by the utility or aggregator.

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Learning-Enabled Residential Demand Response
Security of DR Programs:

- Ability of adversaries to compromise customer-end devices, such as SMs and smartphones, utility/aggregator DRAS, and DR communication channels, has been greatly aided by the automation of DR programs and by a lack of standardization of these programs across the industry.
  - For example, there is no internationally (or, in the case of the United States, interstate) accepted DR communication protocol.
  - Although some protocols (e.g., OpenADR 2.0) have recently gained acceptance, they are still not recognized at the regulatory level.
  - OpenADR 2.0 protocol authenticates, encrypts, and digitally signs the DR information exchanged between the two parties.
  - Although utilities use the OpenADR protocol, the aggregator may use a proprietary communication protocol whose security remains undetermined.

OpenADR Alliance was created to standardize, automate, and simplify Demand Response (DR) and Distributed Energy Resources (DER) to enable utilities and aggregators to cost-effectively manage growing energy demand & decentralized energy production, and customers to control their energy future. OpenADR is an open, highly secure, and two-way information exchange model and Smart Grid standard.

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Learning-Enabled Residential Demand Response
Conclusions:

- Recent advances in communication and information technologies enable new ways and means of enrolling residential resources into DR programs.
- Real-world deployments are still limited due to high capital costs, cybersecurity concerns, and inability to continuously and seamlessly engage with customers.
- DR programs must overcome these limitations, which hinges on designing incentive mechanisms and scheduling routines to account for these limitations while co-optimizing available DR capacity, cost, and reliability.
- Commonly, the small-scale, distributed, stochastic, and heterogeneous nature of residential DR resources complicates these routines.
- Utility-operated DR programs seek to establish a reliable relationship between passive control (e.g., price signals) and the resulting aggregated behaviour of the DR ensemble.
- Online learning methods can be used to tune price signals, using historical and real-time observations to achieve the desired demand response behaviour.
- However, third-party aggregators are more interested in selling flexible capacity to the utility as a service.
- Under this objective, data mining and control can be used to robustly quantify the amount of available flexibility in a given DR ensemble, whilst ensuring minimal data requirements and violations of the comfort preferences of DR customers.

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Learning-Enabled Residential Demand Response Conclusions:

- Regardless of their ultimate objective, any DR program must maintain stringent requirements on its cybersecurity, i.e., to ensure and constantly verify system confidentiality, integrity, and availability.
- While data mining and ML algorithms are generally compliant with DR cybersecurity requirements and often reduce data and communication overheads, they may also enable new entry points for causative attacks that inject manipulated data and disrupt DR system operations.
- Effective residential DR programs have to comprehensively and continuously evaluate their always-changing cybersecurity landscape to take preventive actions for securing their customers and the power system's integrity.

Thanks.

Any Questions?

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