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MEMORANDUM

FROM: Jason M. Ryan, ADER Task Force Chair
Arushi Sharma Frank, ADER Task Force Vice-Chair

RE: Project No. 53911, *Aggregate Distributed Energy Resource (ADER) ERCOT Pilot Project*

DATE: September 1, 2022

On September 1, 2022, the ADER Task Force held a workshop titled "Distribution Systems: Overview and DER Integration."

The following attached material was presented:

- Oncor, Distribution System Overview
    - Any questions regarding the Oncor presentation may be directed to Martha Henson at martha.henson@oncor.com
- AEP, Distribution Real Time Operations
    - Any questions regarding the AEP presentation may be directed to Alex Ramirez at aramirez@aep.com
- Bandera Electric, Distribution System Overview: Apolloware
    - Any questions regarding the Bandera Electric presentation may be directed to John Padalino at j.padalino@banderaelectric.com

A recording of the workshop is available on the Texas ADER Task Force YouTube channel at: https://youtu.be/5JBDM_vITK0.

Aggregated DER Task Force Workshop

Part I: Distribution System Overview

September 1, 2022

WE DELIVER.

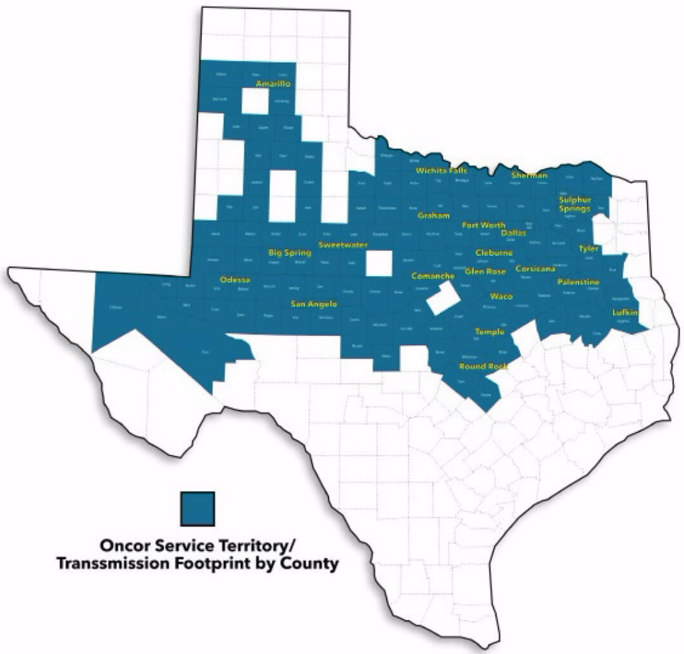
Discussion Outline

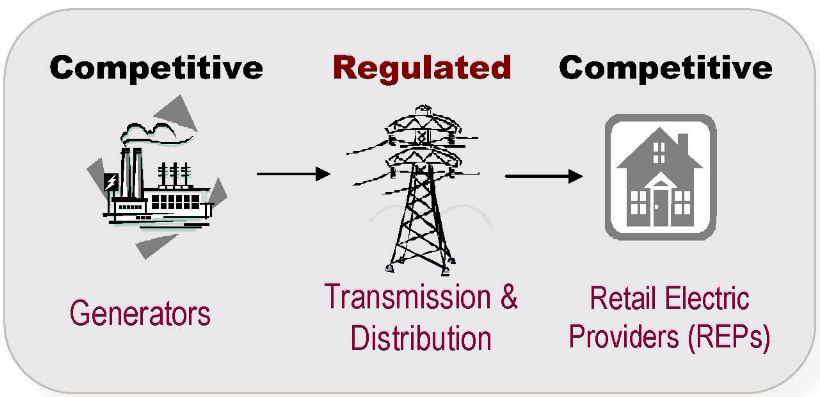
- Oncor Overview
- Utility system architecture
- Transmission and distribution coordination
- Utility real time awareness
- Distribution system visibility and automation
- Outage processing and response
- Operational considerations
- Key Takeaways

3

ONCOR.

Oncor Overview





- Largest regulated transmission/distribution service provider in Texas:
  - ~4,600 employees
  - ~140,700 miles of T&D lines
  - ~3,700 distribution feeders
  - More than 3.8M meters serving ~13M customers
- Service territory covers
  - 100+ counties
  - 400+ incorporated municipalities
- Operates the "poles and wires" that deliver electricity from generating sources to customers.
- Oncor employees safely and efficiently design, construct, maintain and upgrade this infrastructure

Utility System Architecture

69 kV, 138 kV, 345 kV

<60 kV

Transmission Lines

High voltage lines transfer bulk power from generators to load centers

Networked system with looped paths and redundancies

Substations

Take power from transmission lines and transfer it to distribution system

Output of substations are a number of distribution feeders

Distribution Lines

Distributes electricity from substations to end-use homes and businesses

Mostly a radial system with power flow in one direction

Oncor		
18,000+ miles	900+ stations	122,000+ miles

5

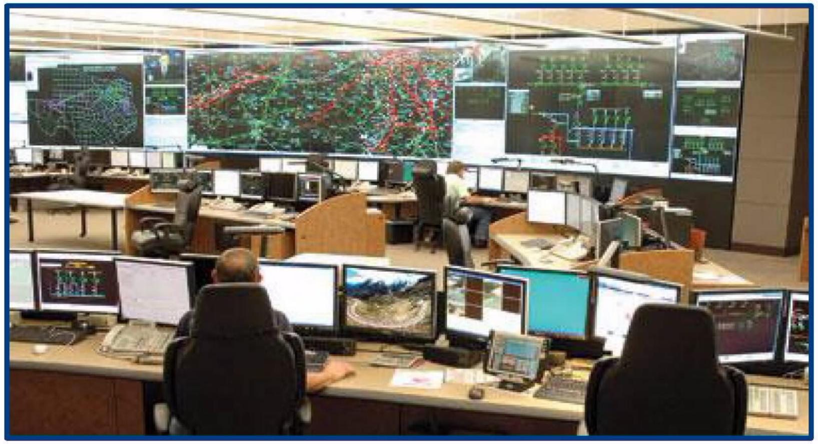
Utility System Real-Time Awareness

	Real-Time Generator Information*	Real-Time Utility Facility Information	Outages / Clearances / Abnormal Conditions
Transmission	• Telemetered real-time capacity for real and reactive power • Generator outages • Voltage set points • Considered in SCED	• Control and monitoring of all transmission elements though SCADA • State estimator • Real-time contingency analysis • Management of system within various limits (thermal, stability, GTC, IROL, etc.)	• Facility outages are coordinated with planned generation outages when possible • ERCOT reviews and approves Resource and transmission planned outages • Often, transmission events do not result in sustained service interruptions to customers
Distribution	• None	• Control and monitoring of low-side elements in substation • Breaker level load alarms but no load flow management • Control and monitoring D SCADA devices and automation • AMS meter status (ping) • Load estimates per D element but no real-time interval data	• Equipment outages often affect end-use customers (momentary, sustained, relay setting changes, abnormal conditions) • No approval or communication with ERCOT or Transmission Control Room regarding feeder configuration changes • Customer restoration coordination with Transmission Control Room for transmission-level outages

6

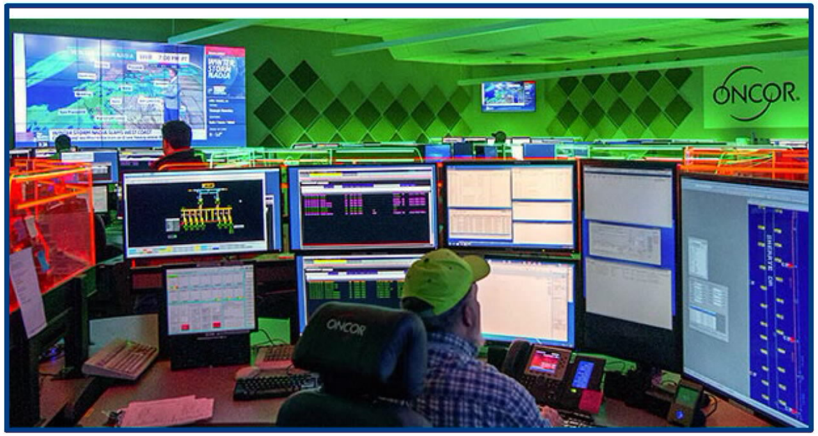
* Unregistered DG; not inclusive of DGRs, DESRs or SODGs

Transmission & Distribution Coordination



Transmission Control Room

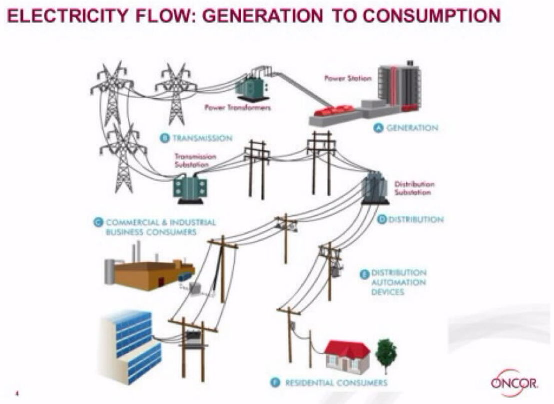
- Real time, continuous transmission grid monitoring
- Manages constantly-changing grid conditions
- Coordinate switching/tagging orders for maintenance & construction
- Operational interface with ERCOT
- Examples of non-storm activities: new construction, maintenance, upgrades, system alarms, monitor load patterns and contingencies, coordination with ERCOT and neighboring TSPs



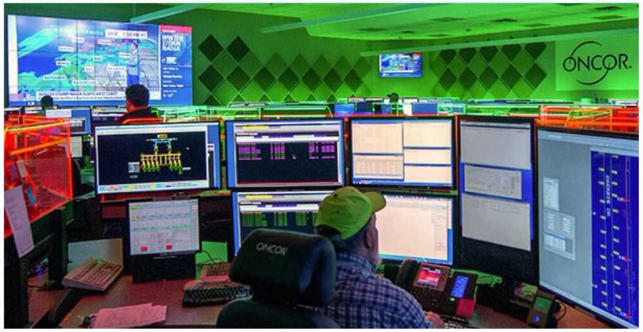
Distribution Operations Centers

- 24-hour outage and field emergency response coordination
- Coordination of maintenance and construction operations (clearances)
- Weather monitoring and storm restoration
- Operational interface with TGO @ feeder breaker
- Examples of non-storm activities: new construction, upgrades, maintenance, re-locations, telecom installations (5G, CATV), dig-ins, car-hit-pole, support police and FD

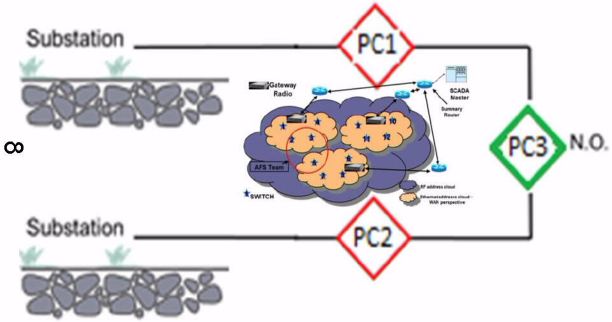
Distribution Activity, Visibility, and Automation



- > 122k line miles connecting > 1m active devices
- (transformers, capacitors, switches)
- > 250,000 fuses
- > 80k switchable devices (11% SCADA enabled)
- > 420k SCADA points (control or monitoring)
- Urban and rural service territory (>100k square miles)
- Two 24hr DOCs staffed with 6-12 FTEs per shift



- Managing > 500k outage and emergency tickets/yr
- Supporting > 40k construction projects/yr
- Executing > 15k load switching operations /yr
- Connecting > 80k of new premise connections /yr
- ~10m operational meter pings /yr



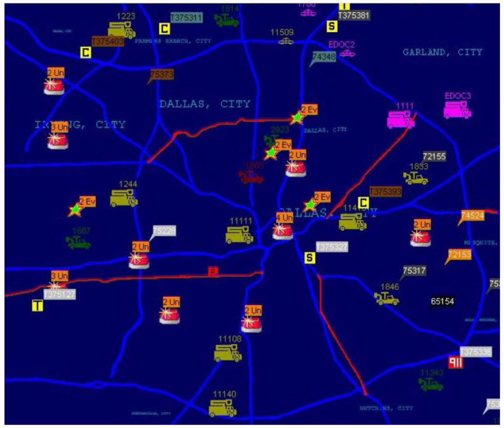
- > 2.5k peer-to-peer automated switches
- AMS/ADMS integration
- Trouble Analysis
- Load estimation, FLOC, FLISR
- Situational information filters, UIs, and alarms

ONCOR

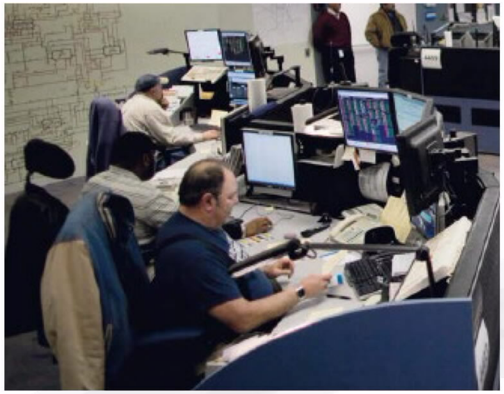
Distribution Outage Response Process

AMS, Text, Web, Call

IT Backend or Call Center



Outage Event Created (ETOR)/ Customer Notification



Emergency SCADA Switching

Trouble Resource / Repair Crews

Lights Back On

Distribution System Operational Considerations/ADER Availability

Reliability Metrics

- System Average Interruption Duration Index (SAIDI)
  - Average number of minutes electric service is interrupted per consumer in a year
- System Average Interruption Frequency Index (SAIFI)
  - The average number of electric service interruptions per consumer in a year

Major Storms

- Significant infrastructure damage can disconnect hundreds of thousands of distribution customers at a time, for hours or days

ERCOT System Emergencies

- When generation is insufficient to serve ERCOT system load, ERCOT will instruct Transmission Operators to implement Manual Load Shed
- Manual Load Shed is accomplished by disconnecting distribution feeders (i.e., customers)

Key Takeaways

- Utilities have ultimate responsibility for operating a safe and reliable grid in a complex, dynamic environment
- Real-time information on DER behavior is limited or nonexistent at the utility level
- Aggregate reductions in customer load are fairly well understood
- Impacts of simultaneous, coordinated injections of energy into the distribution system are not well understood
- While ERCOT manages the Ancillary Services market, ERCOT oversight of distribution systems is not feasible
- High DER penetration on a feeder may necessitate that a utility perform protection upgrades, balance phases, or take other measures to ensure reliability of service
- During outages/system emergencies, a utility's priority is restoration of service to customers, not keeping DG interconnected
- The distribution system is dynamic and subject to reconfigurations without any visibility to customers, REPs or ERCOT

Distribution Real Time Operations

American Electric Power

August 2022

AEP Texas Overview

AEP TEXAS
An AEP Company

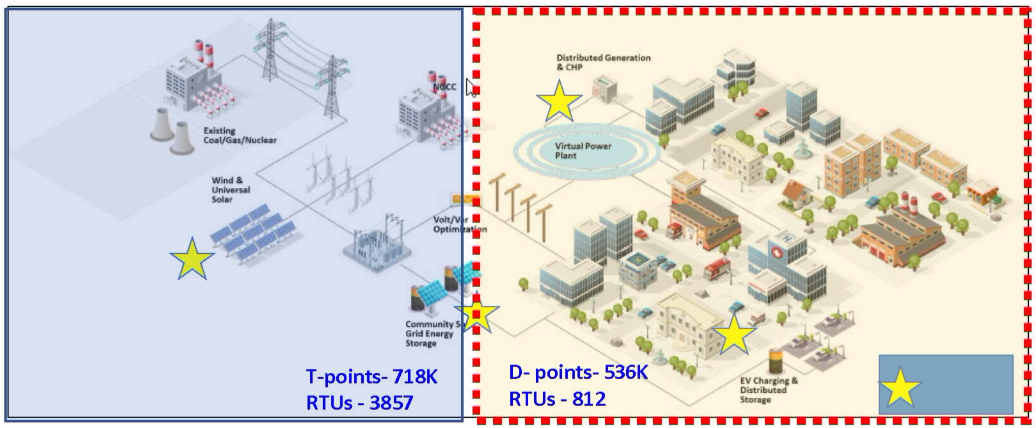
AEP Texas, headquartered in Corpus Christi, delivers electricity to over one million homes, businesses and industries in south and west Texas. AEP Texas delivers electricity, builds new power lines, restores service and reads the meters for REPs throughout the service territory.

<u>AEP Texas Key Operating Statistics</u>

Meters:	***1,082,490***
	32.9 Million
MWh Delivered:	
	97,000
Service Area (sq. miles)	
	372
Cities & Towns Served:	
	92
Counties Served:	
	44,300
Miles of Distribution Lines:	
	8,412
Miles of Transmission Lines:	

13

The Distribution network of the future will require advanced technology to manage the growing scale (control points), complexity (DERs), and multi-source power flows



Generation Transmission Distribution

DER penetration is continuing to accelerate the need to deploy robust real-time tools that are needed to operate the D-wires system.

- AEP Texas & I&M are examples of this explosive growth and shifting regulatory environment.
- Multi-source power flow will require orchestration of a complex blend of load, generation, storage and automation
- FERC 2222 allows Distribution assets to serve wholesale market needs, potentially causing local constraints/issues.

D-wires system will become a critical part of the generation/load balancing equation.

- Shift from central to distributed generation will require multi-direction movement to maintain the overall balance between generation and customer loads.
- This movement of distributed generation may occur locally via the D wires system, or in some cases need to feed back through the T wires system to reach loads on a different part of the D wires system (i.e. 2-way power flow).
- The current electric grid was not designed to operate multi-direction

Foundational OT & IT capabilities required to operate an integrated grid of the future

- Implement an **Advanced Distribution Management System** (ADMS) and operational **Distributed Energy Resource Management System** (DERMS)
    - **Single distribution network/power flow model and single sources of truth** to manage our distribution assets at scale
    - Data readiness
- **Harden Distribution Real Time OT infrastructure and operating environments** by implementing cyber, physical and access controls.
- **Establish secure real-time data exchanges** across G, T & D control systems; Implement non-real-time data exchange platform for enhanced situational awareness & operator assist functions

Operational DERMS capabilities will be critical in managing high penetrations of DER

AEP DAY 1 Operational DERMS

Administration:

- Establish DER record and maintain data:
  - customer/location, nameplate, initial device settings, metering configuration, market/customer program status, interconnection application records and status, etc.

Visualization:

- Visualization of DERs in the ADMS network model, and aggregation simplification

Operations:

- DER integration with Load Flow/ Power analysis studies and advanced applications (FLISR/VVO);
- Operational forecasting;
- Override capability;
- Safety related checks to prevent unexpected two-way power-flow
- Flexible and Secure Data Exchanges and Architecture

Additional, long-term operational considerations for exploration during pilot

Considerations:

- Utilize ADMS/DERMS advanced situational awareness tools to properly manage a “system view” across T&D wires.
- Advanced engineering/studies regarding week/day ahead and real time issues.
- Data flows and interfaces between RTO, Aggregators, Transmission, and D operators.
- Multi-source power flow management; gen/load balance
- DER override mechanism for emergency conditions (day-ahead/real time).

Texas Pilot Readiness Considerations

Systems/Tools

- Current systems/tools limitations create potential blind spots; New ADMS/DERMS tools not available until 2025+
- Explore potential interim solutions
- Security considerations for data exchanges required for real time monitoring

Location considerations

- Data readiness
  - Model connectivity, Model attribution
- Scada readiness
  - Station, line SCADA availability
  - Additional SCADA monitoring needs?
  - DACR/ VVO ? (does this hurt or help?)
- Hosting capacity
  - Individual and aggregated planning studies
  - Inventory of existing DERs
  - Adequate capacity to host large number of DERs with no required line/station upgrades
  - Reliability (areas where DER could help/hurt)
  - Powerflow considerations (backfeed to Transmission)

Other

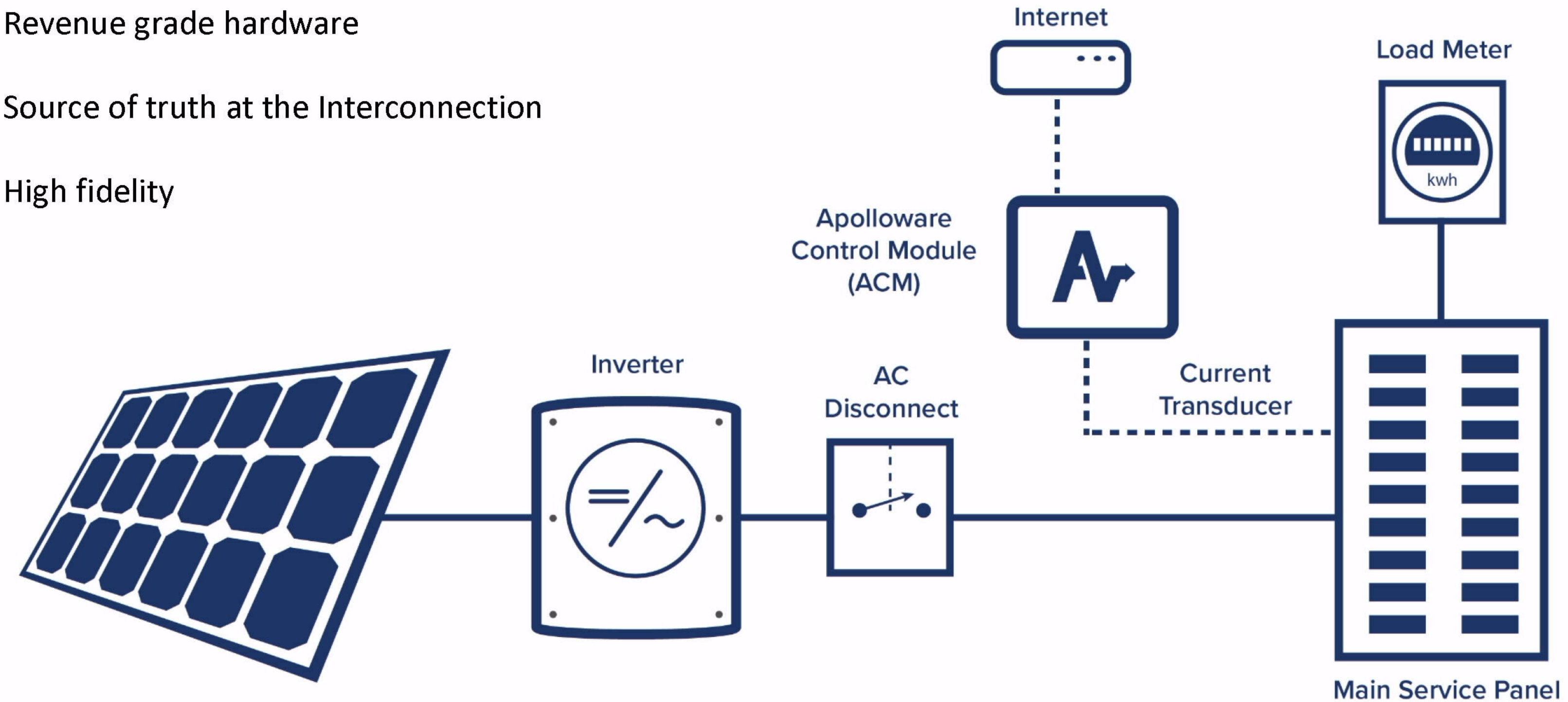
- Storm/Load shed planning considerations
- Billing/settlements; integration into existing process/workflows

Bandera Electric Cooperative ADER Task Force

DISTRIBUTION SYSTEM OVERVIEW: APOLLOWARE

SEPTEMBER 1, 2022

- Revenue grade hardware
- Source of truth at the Interconnection
- High fidelity



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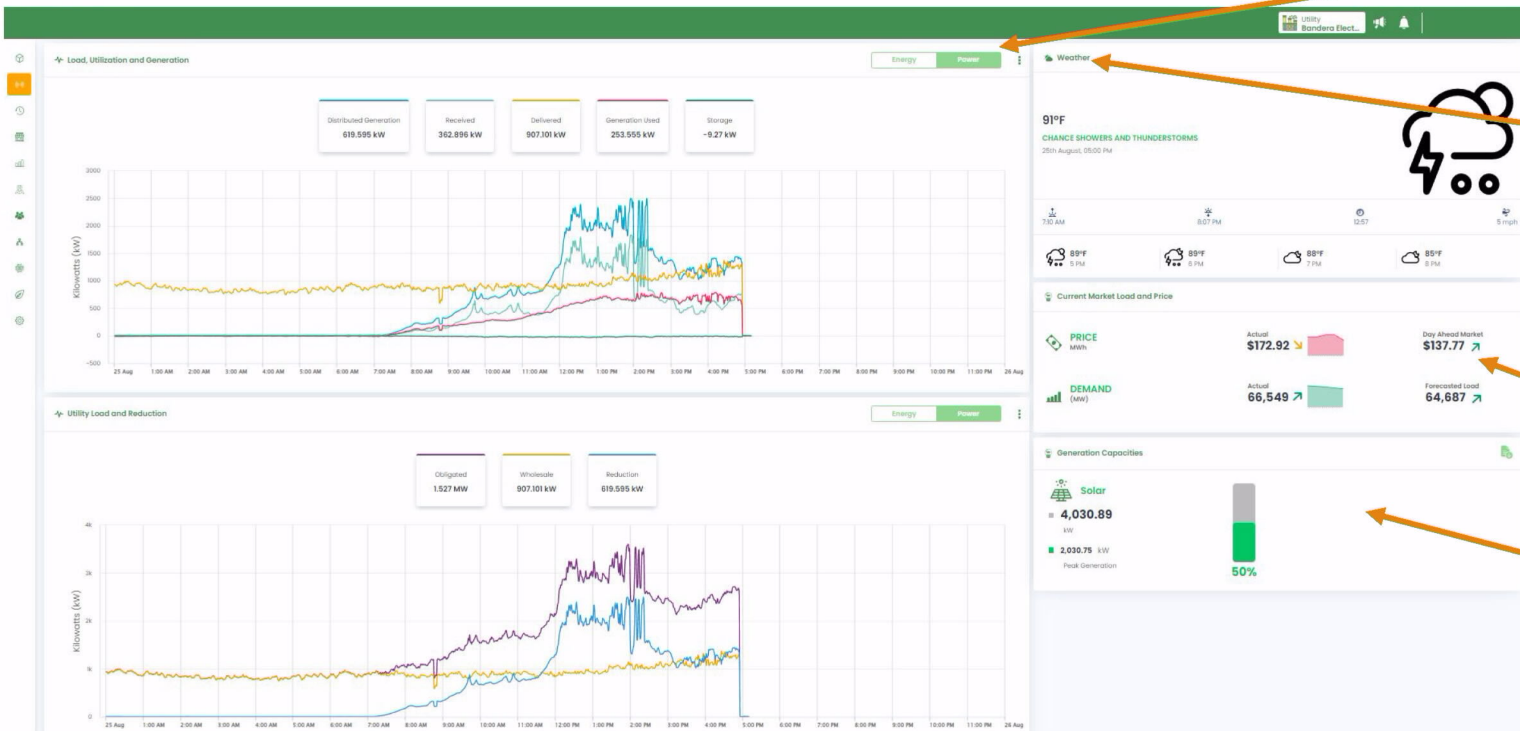
Real Time Utility Aggregation



- Graph can be reported in Power and Energy
- National Weather Service integration, reporting from nearest weather station
- ERCOT Integration updated every 15 minutes
- Total aggregated solar for the cooperative and real time peak

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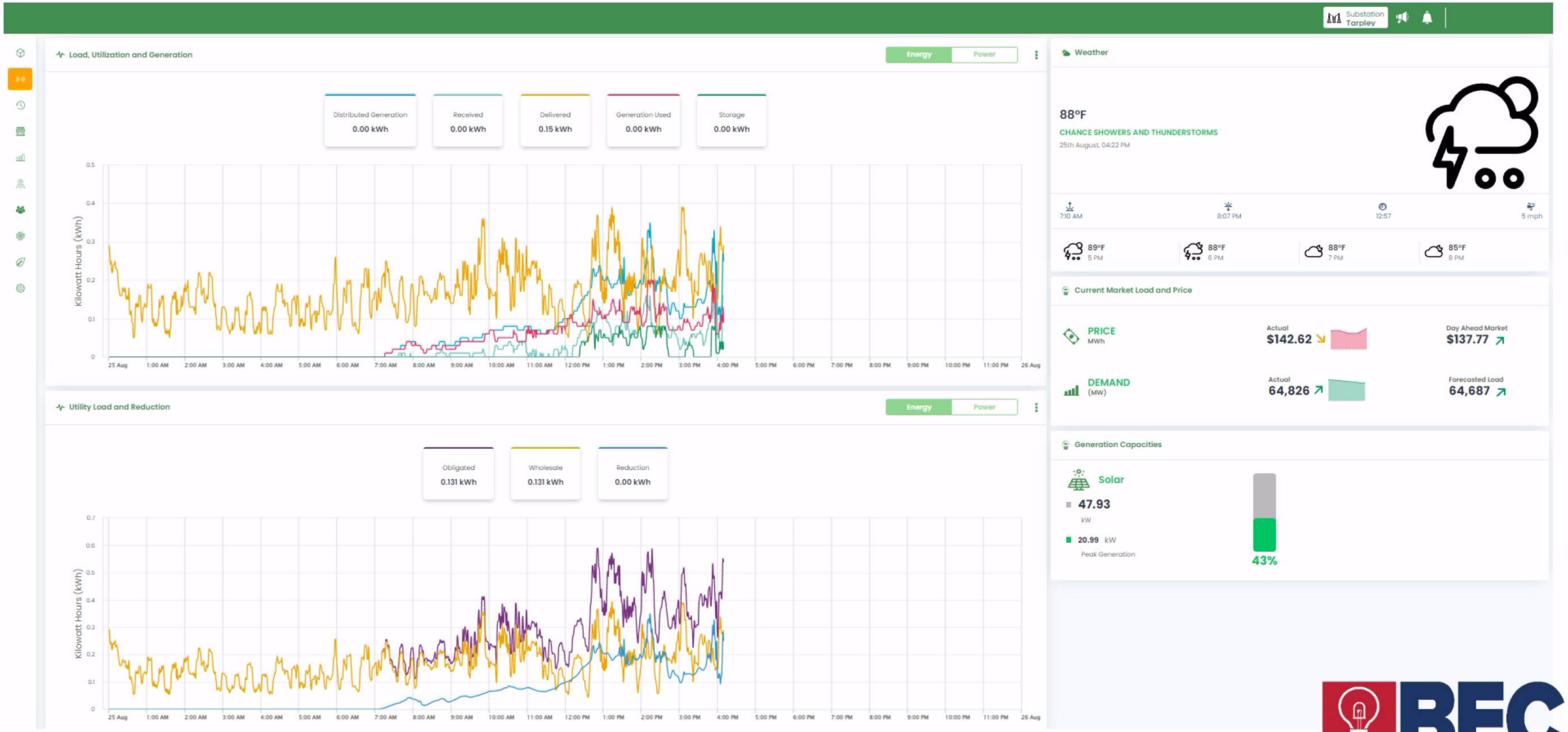
- **All** Distributed Generation resources (solar, wind, energy storage) interconnecting to the BEC grid are required to install Apolloware per rate tariff.

Real Time Substation Aggregation



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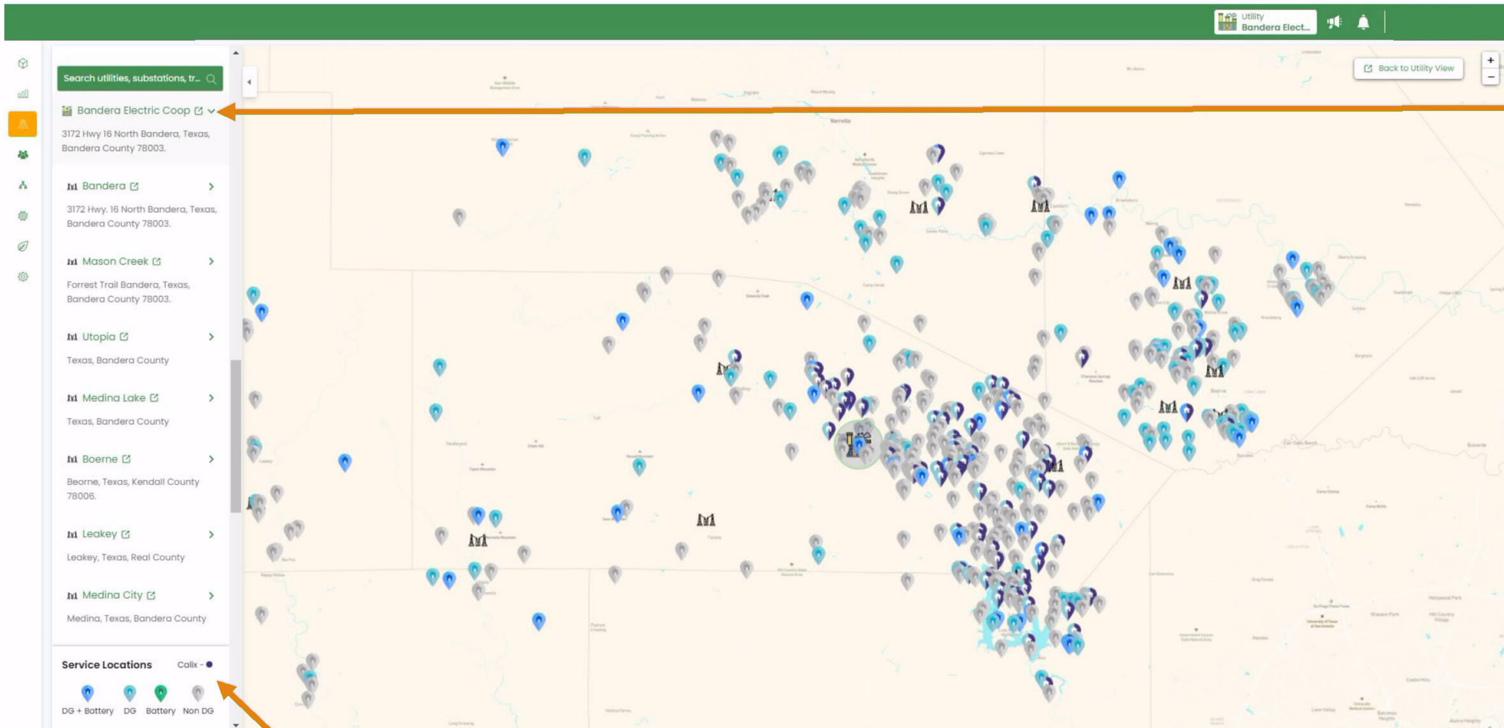
Site Mapping and Connectivity Model



- Connectivity Model is visible here, defined by substation, feeder, phase and service location

- Service Locations identified by type

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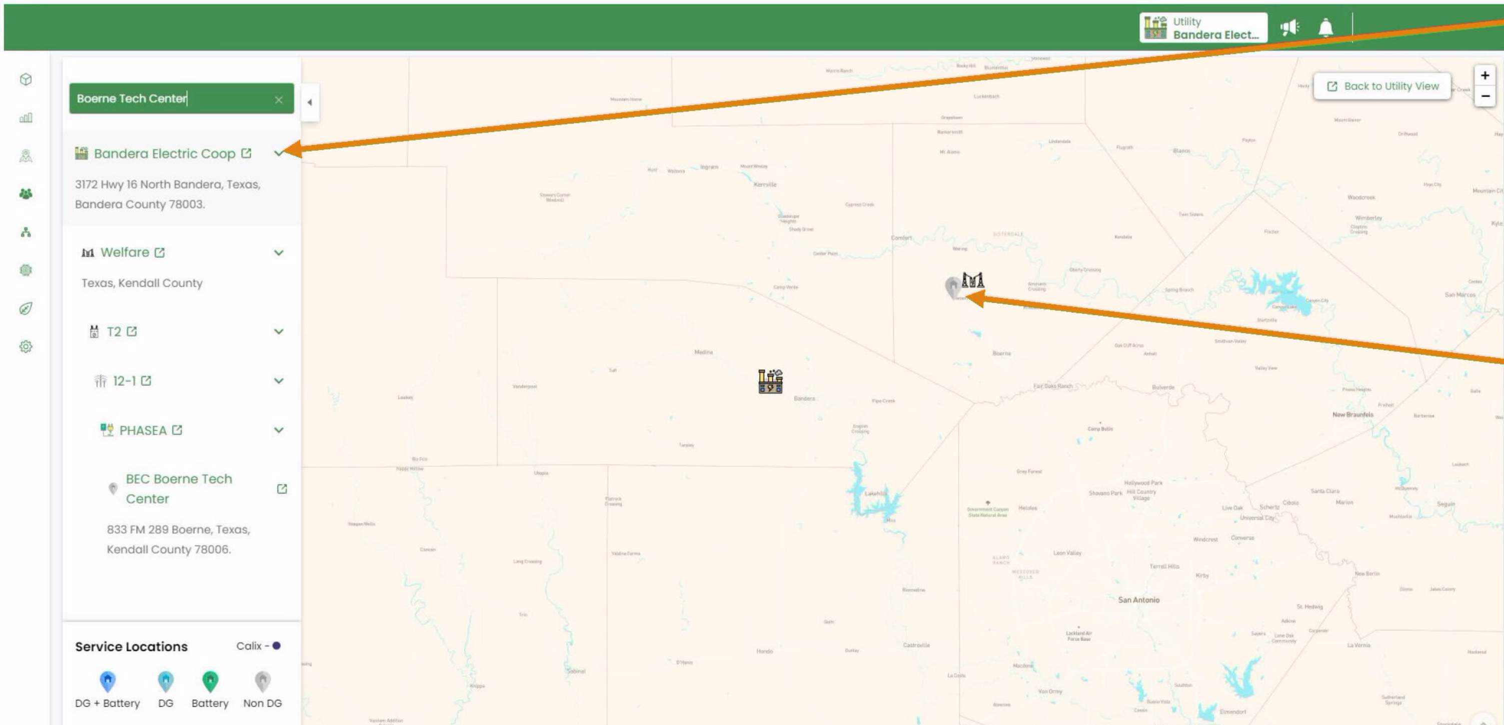
Service Location Connectivity Model



- Connectivity Model:
  - Utility
  - Substation
  - Transformer
  - Feeder
  - Phase
  - Service Location
- Able to view Service Location on the map

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Alerts – Capacity – Fleet

Substation	15
Transformer	20
Feeder	55
Phase	165
Mid line	571
End of Line	26

Generation Capacities

Solar

4,030.89
kW

2,030.75 kW
Peak Generation

50%

Fleet

	Today kWh			Yesterday kWh	
Air Conditioner	1,393.16	$92.96	↘	8,629.65	$576.17
Furnace	402.21	$26.79	↘	1,809.21	$121.04
Pool Pump	557.83	$37.10	↘	2,239.83	$149.45
Well Pump	168.59	$11.28	↘	902.26	$60.44
EV Charger	58.16	$3.90	↘	215.73	$14.47

- Connectivity Model Alerting
- Total aggregated solar for the cooperative and current peak
- Aggregated midnight to current sub-circuit monitoring

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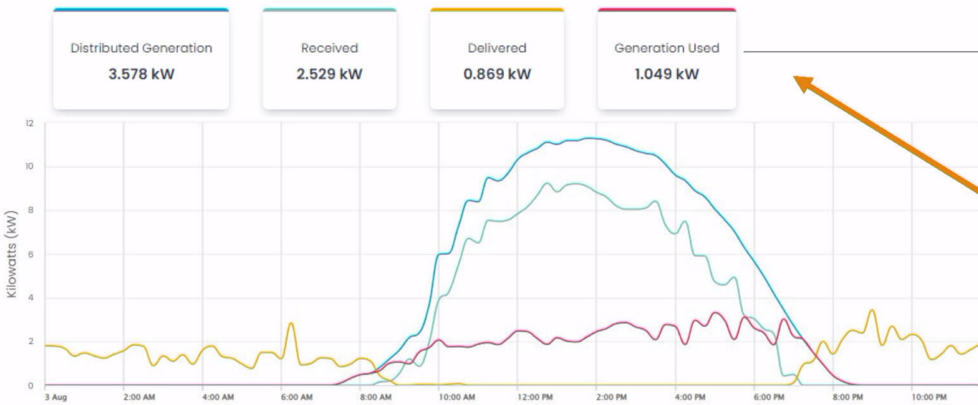
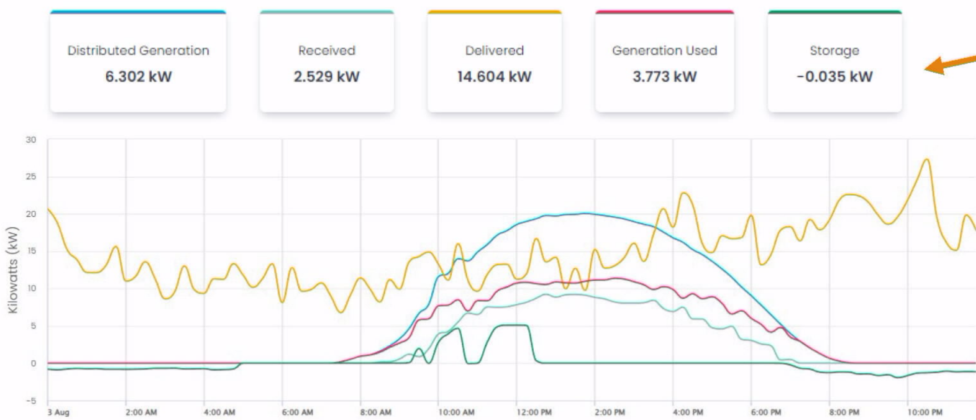
Real Time Load, Utilization, and Generation





Information is available and aggregated at:

- Service Location
- Phase
- Feeder
- Transformer
- Substation
- Utility Levels

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Frequency

Power Quality Metric - Frequency

Frequency is monitored at each service location and aggregated across the connectivity model

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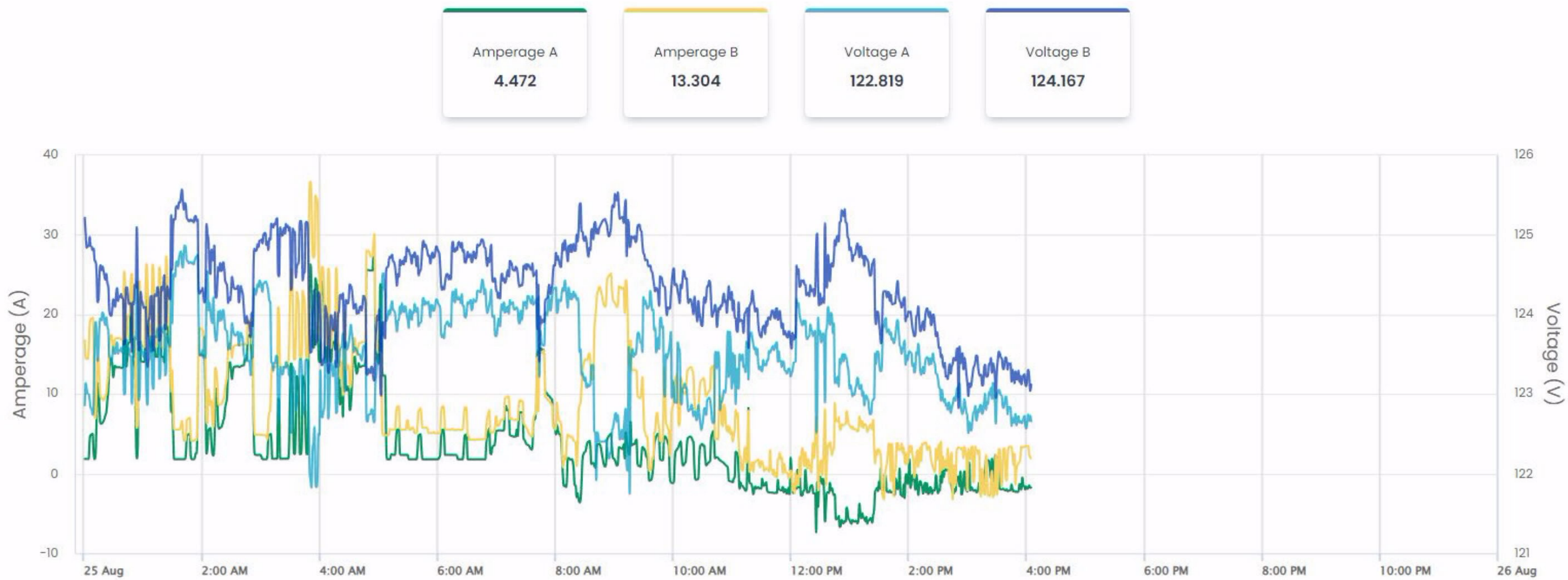
Power Quality Metric

Meter Amperage-Voltage (Phases)



Amperage-Voltage is monitored at each service location and aggregated to the substation and the utility

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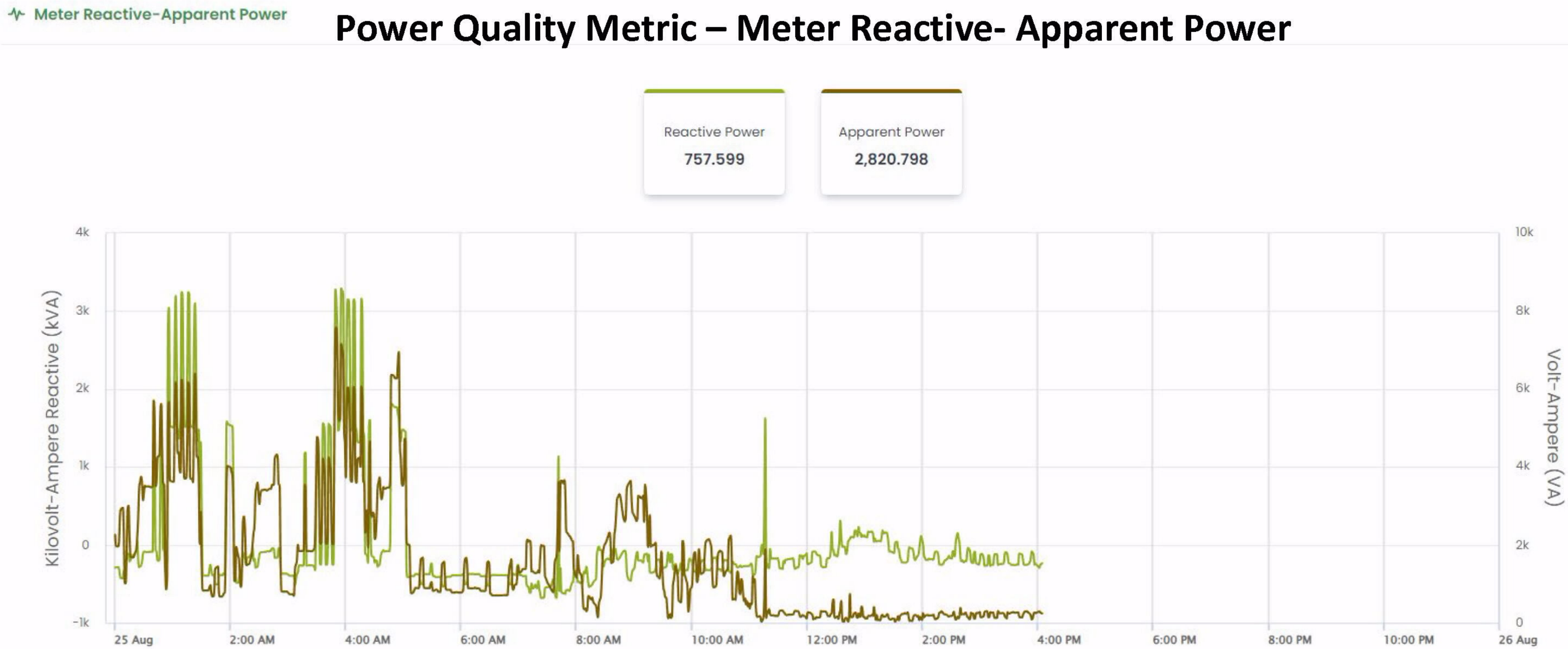
Power Quality Metric – Meter Reactive- Apparent Power



Reactive-Apparent Power is monitored at each service location and aggregated across the connectivity model

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Power Quality Metric

Meter Power Factor is monitored at each service location and aggregated across the connectivity model

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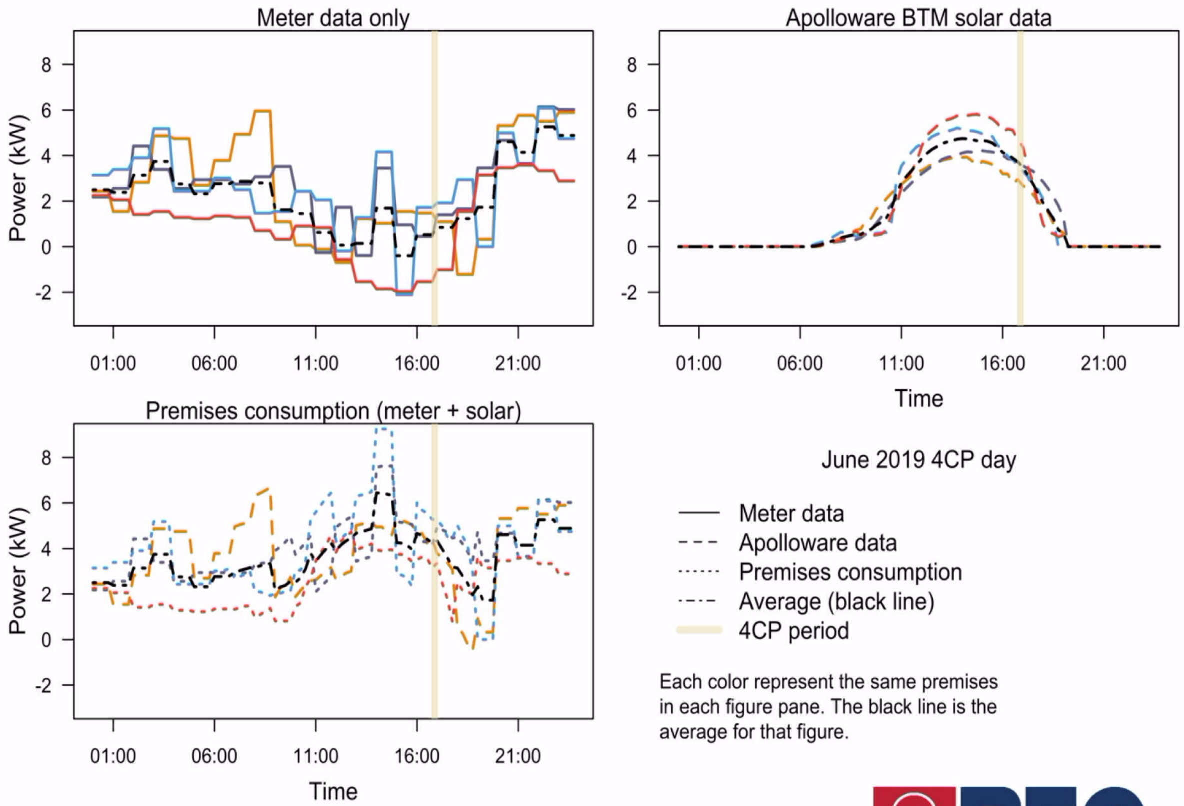
<u>Doesn't this information come from AMI?</u>

- Smart Meter data is low fidelity, delayed, and lacking.
- Directly measuring DERs in real time can give more insight into anomalies
- Identifying how customers use, generate, and store energy.
- Apolloware data tells the whole home story



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Texas Homes During Winter Storm Uri

- What was happening behind the meter?
- How did DER assets perform?
- What can we learn from weather events, real time?
- BEC was positioned to respond, 87% Member Satisfaction post event.

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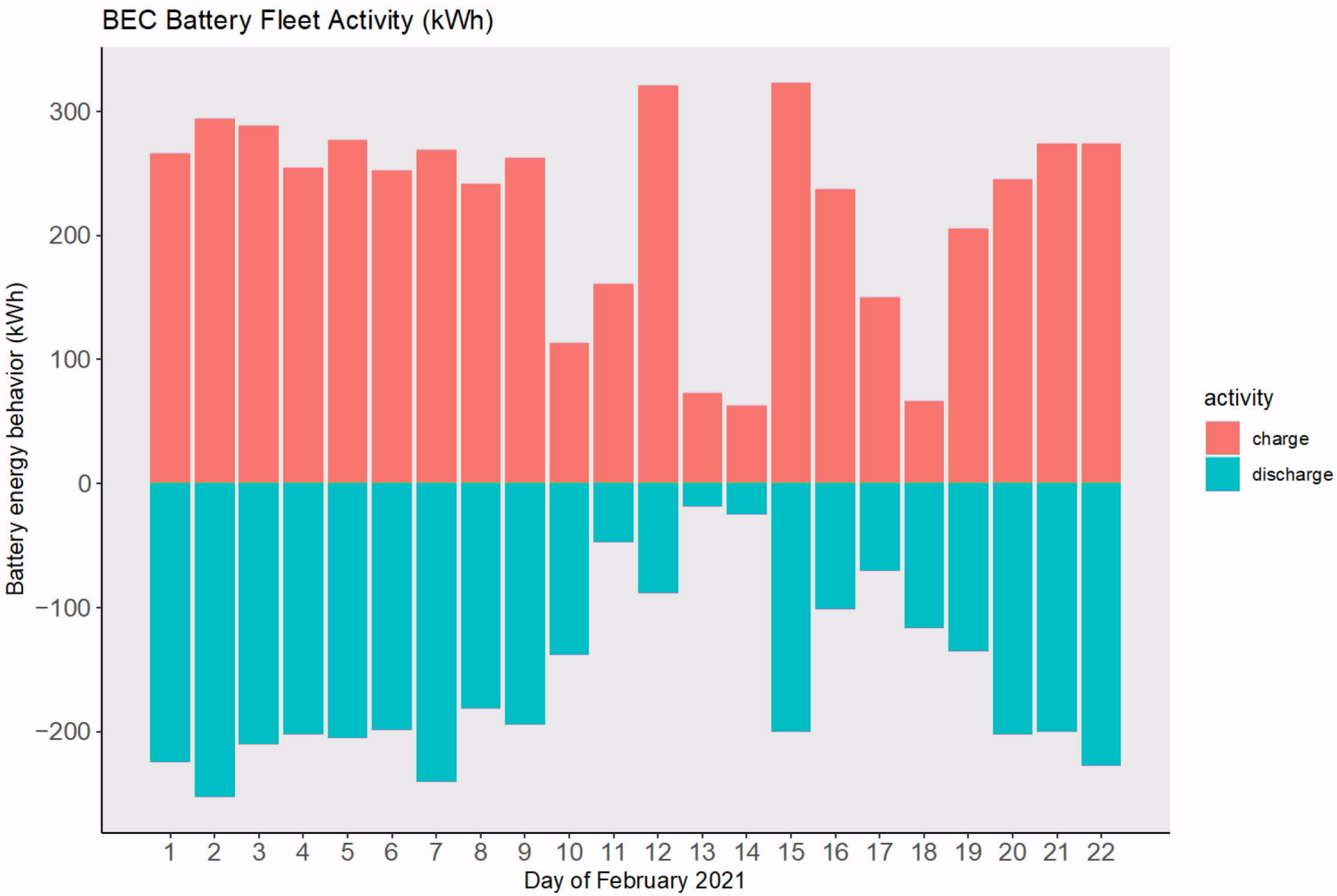

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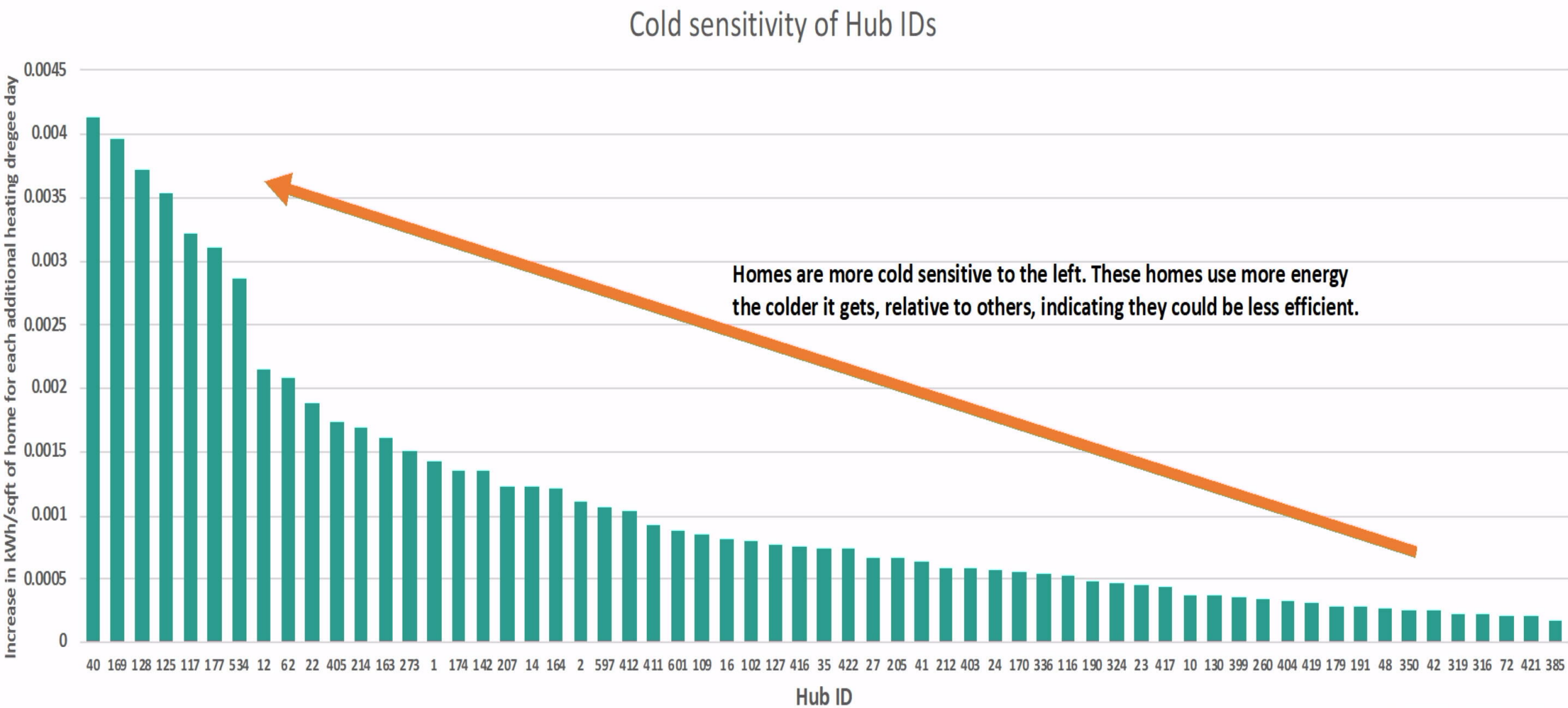

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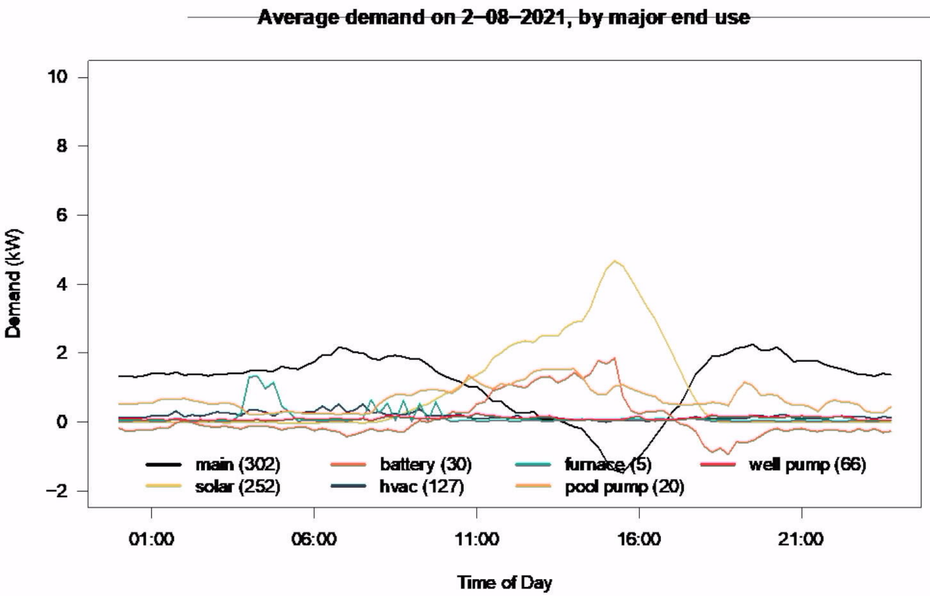

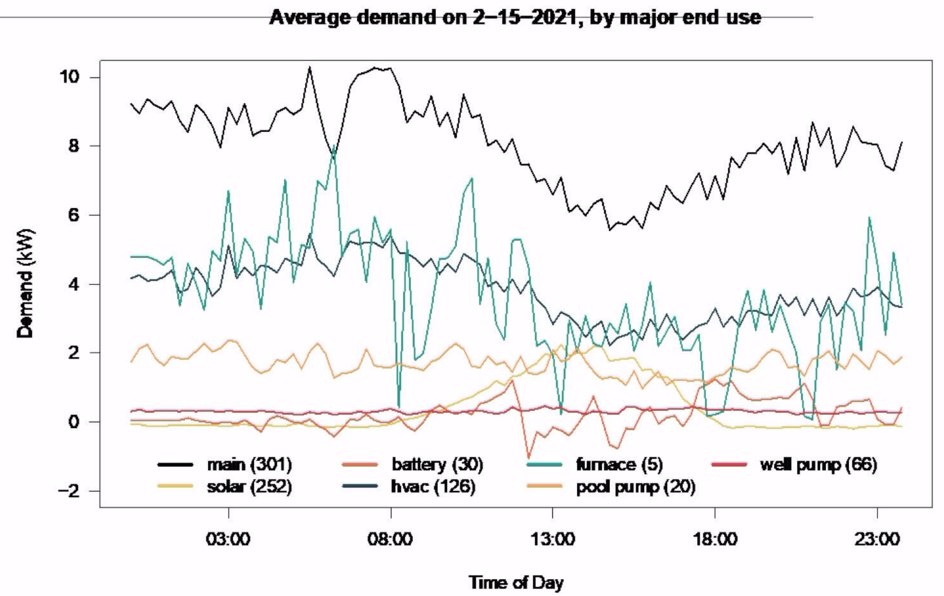

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Key Takeaways

- DER Data in context of utility operations is critical – grid reliability, power quality, safety, and customer experience
- Customer understanding DER performance is critical - 20% of DER installations have performance issues from day 1
- Extreme weather impacts when batteries are charging because of the primary use case for back up power
- Solar installations are over built because the offset is calculated on billing data only
- Building envelopes are energy inefficient
- On average 35% of the energy delivered to a residential home in our territory is lost behind the meter

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