Enhanced Control, Optimization, and Integration of Distributed Energy Applications (ECO-IDEA)

Murali Baggu, Harsha Padullaparti, Santosh Veda, Jing Wang, Francisco Flores-Espino, Ismael Mendoza, and Fei Ding

National Renewable Energy Laboratory

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Technical Report
NREL/TP-5C00-82521
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Errata

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Executive Summary

With support from the U.S. Department of Energy Solar Energy Technologies Office, the National Renewable Energy Laboratory (NREL) partnered with Xcel Energy, Schneider Electric, Varentec, and Electric Power Research Institute (EPRI) to meet the goals of the Enabling Extreme Real-Time Grid Integration of Solar Energy (ENERGISE) program. This project developed and validated an innovative data-enhanced hierarchical control architecture that enables the efficient, reliable, resilient, and secure operation of future distribution systems with a high penetration of distributed energy resources like solar energy. The architecture enables a hybrid control approach where a centralized control layer is complemented by distributed control algorithms for solar inverters and autonomous control of grid edge devices. It is fully interoperable and includes all the cybersecurity aspects necessary for reliable and secure system operation. The hybrid approach can seamlessly integrate multiple voltage-regulation technologies, both at central and grid-edge levels, which enables reliable and efficient system operation in the face of unpredictable conditions. The overarching goal of the Eco-Idea project is to develop, validate, and deploy a unique and innovative Data-Enhanced Hierarchical Control (DEHC) architecture that comprehensively addresses the formidable challenges associated with proliferation of high penetration of distributed PV such as reverse power flows, transients from variability of PV systems[1], feeder load balancing, and voltage stability[2] These issues are exposing the weaknesses of existing grid operations and controls—including, but not limited to, lack of grid situational awareness, heuristic and slow-acting control actions, latency of control for emergency situations, and points of failure in communications. The proposed architecture will comprehensively resolve the deficiencies of current operational settings— where monitoring and control solutions proposed across industry and academia may not be interoperable and may not coexist in the same system—and will enable an efficient, reliable, resilient, and secure operation of future distribution systems with penetration of solar energy well beyond current limits. The DEHC architecture was developed and validated rigorously through hardware-in-loop simulations in the laboratory environment and deployed on the field.

[1] Y. Liu, J. Bebic, B. Kroposki, J. de Bedout, and W. Ren, “Distribution system voltage performance analysis for high-penetration PV,” in *IEEE Energy 2030 Conf.*, Nov. 2008.

[2] A. Woyte, V. Van Thong, R. Belmans, and J. Nijs, "Voltage fluctuations on distribution level introduced by photovoltaic systems," in *IEEE Transactions on Energy Conversion*, vol. 21, no. 1, pp. 202-209, March 2006.

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Background

The Enhanced Control, Optimization, and Integration of Distributed Energy Applications (Eco-Idea) team combines crosscutting expertise from DOE national laboratories (NREL), industry (Schneider Electric, Varentec Inc., and EPRI) and electric utility (Xcel Energy), and it is uniquely positioned to translate the latest engineering advances into breakthrough approaches targeted to the needs of future power systems with extremely high levels of solar energy. NREL has been conducting cutting-edge research for more than 20 years with a long list of accomplishments in developing solutions to reduce barriers to clean-energy deployment and grid modernization; NREL has an ongoing Grid Modernization Laboratory Consortium (GMLC)-funded project that develops a platform for testing Advanced Distribution Management Systems (ADMS), and an ARPA-E project where innovative distributed control algorithms are being developed; these projects will cross-fertilize the proposed effort with the ultimate goal of enabling high penetration of photovoltaic (PV) systems with reliability guarantees. Schneider Electric is leading the development of ADMS, providing unique solutions that integrate legacy and next-generation controls and distribution-network automation technologies; Varentec is leading the way in decentralized control with commercial pilots at more than 20 utilities and with over 2,000 voltage-management devices committed and installed. Xcel Energy and Austin Energy are at the forefront of the transformation of distribution systems into sustainable networks, where massive amounts of PV systems are being deployed. EPRI is well known for providing expertise in developing Interoperability Test Procedures.

Current Challenges and Baseline

The proliferation of distributed PV is creating operational challenges for the distribution grid such as reverse power flows, transients from variability of PV systems, feeder load balancing, and voltage stability, just to name a few. These issues are exposing the weaknesses of existing grid operations and controls—including, but not limited to, lack of grid situational awareness, heuristic and slow-acting control actions, latency of control for emergency situations, and points of failure in communications. With respect to voltage variability and the increased likelihood for overvoltage conditions, it is worth emphasizing that the ANSI C84.1 standard is enforced at the low-voltage service entrance (i.e., at the edge of the grid), whereas most control actions currently occur at the medium-voltage (MV) level. Figure 1, illustrating voltage data collected from 1,005 meters on a 9.5-MW feeder in the U.S., indicates high levels of volatility in voltage throughout the year. This example clearly shows the limitation of controlling the system with slow-acting controllers at a few primary legacy assets (i.e., cap banks and voltage regulators) in the system with high PV penetrations. Overall, these issues call for new control paradigms that can comprehensively pave the way to next-generation power-grid settings where a massive integration of solar energy is operated with reliability and efficiency guarantees. To this end, next-generation distribution system planning and operation tools are required to be dynamic, automated, data-driven, highly scalable, and cost-effective, and must enable effective decision-making at time scales that match the dynamics of intermittent generation. These require complete data remediation of distribution topology, full knowledge of load and generation patterns, and pervasive communication among controllable and sensing assets. To this end, control architectures are envisioned to leverage a hybrid approach whereby the speed and reliability of distributed control is coupled with the situational awareness and flexibility offered by centralized ADMS. However, it is a significant challenge to implement monitoring and control solutions that are interoperable and coordinate to achieve the common goal of a reliable system-wide operation—given the diversity of technologies and vendors, and the competitiveness of the grid-edge marketplace.

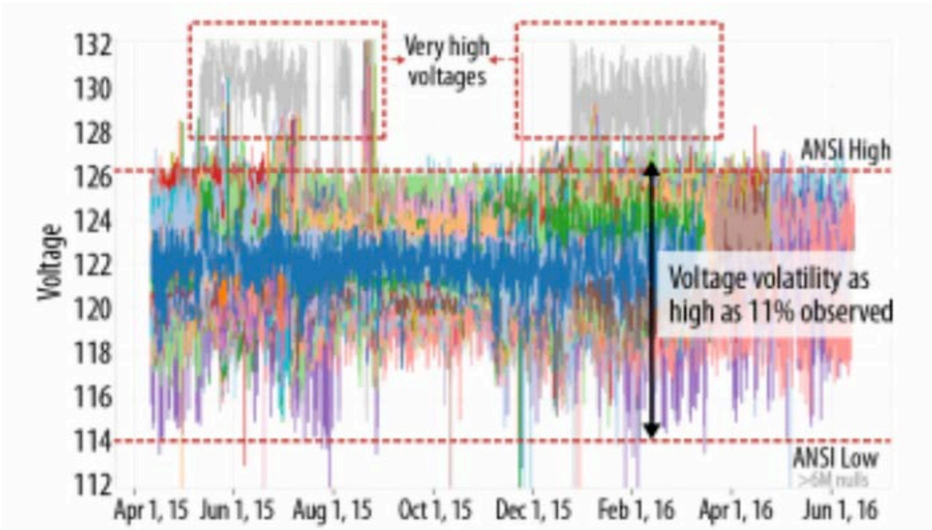


Figure 1. Voltage variability due to the presence of high penetration of solar photovoltaic (PV) systems

Proposed Solution

The proposed Data-Enhanced Hierarchical Control (DEHC) framework provides a hierarchical yet unified solution to tackle the critical challenges associated with *Enhanced System Layer*, *Traditional System Layer*, *Telecom & Data Layer*, and *Local Device Layer*. The DEHC involves the development and the systematic integration of advanced applications for real-time operation and control of traditional Volt/VAR resources (i.e., load tap changers, voltage regulators, capacitor banks) and edge devices (i.e., PV inverters and grid-edge devices) offering reactive and active power support[3] and real-time monitoring and forecasting of the distribution grid to gain (and maintain) comprehensive situational awareness and to support the control decisions offered by DEHC. The following are the features of the DEHC architecture:

1. *ADMS-centered operation.* The project leveraged the capabilities of the Schneider Electric ADMS, which utilizes a full-scale network model populated from the geographic information system (GIS), customer information system (CIS), substations, feeders, loads, distributed energy resources (including PV systems), and other resources along with the associated supervisory control and data acquisition (SCADA) points to leverage advanced applications for network analysis and control. The Real-Time ADMS instance collects the readings from the field via SCADA and Advance Metering Infrastructure (AMI) systems. The ADMS is deployed on servers located in the utility control center, in a redundant fashion, and uses SCADA to collect telemetry and issue commands directly to field devices using standard protocols such as DNP3 through traditional RTUs, dedicated concentrators, or intelligent electronic devices.

[3] S. Genc, M. Baggu, "Look ahead Volt/VAR Control: A comparison of integrated and coordinated methods, *IEEE PES T&D Conference and Exposition*, 2014.

2. *A synergistic ADMS- grid-edge operational setup.* Grid-edge devices were used to increase the flexibility in controlling the voltage profile. The grid-edge devices use power-electronics-based, fast-acting, decentralized shunt-VAR technology for voltage regulation. Each device connected to the secondary side of a pole- or pad-mounted service transformer can inject 0 to 10 kVAr and can regulate the voltage tightly (± 0.5% within control range) at local and feeder wide scale. Although the grid-edge devices are autonomously controlled once a setpoint is dispatched, they can be provided with a new setpoint voltage via the grid-edge device head-end server at regular intervals (minutes to days, as needed).
3. *Adding fast-regulation capabilities.* The project considered advanced networked-control schemes for PV systems to enable effective voltage regulation in the presence of fast time-varying load and ambient conditions. The VVWO application of the ADMS coordinates with the Real-time Optimal Power Flow (RT-OPF) for controlling the PV inverters. The RTOPF routinely computes the setpoints for the PV inverters and other controllable assets over a timescale of minutes, whereas the distributed PV-inverter controllers will act at a faster timescale (seconds or even subsecond) and will adjust the PV output power around the setpoints received by the ADMS to ensure that voltages are within given limits even in the presence of fast-changing irradiance conditions. These new control algorithms provide immediate control at the edge while also reacting to dispatch requests from ADMS.
4. *Gaining and maintaining comprehensive situational awareness.* As part of the ADMS platform, State Estimation (SE) and Power Flow (PF) applications achieve an accurate picture of system state (loads and voltages) at every network element. In particular, SE is used for estimating distribution network state considering remotely monitored data (e.g., switchgear status, measurements, tap changer positions) and initial load data derived from load curves given in the model or from the previous estimated state. SE combines the telemetered real-time and model data into a consistent set of state variables.
5. *A cyber-secure and interoperable architecture.* The DEHC platform is cyber secured based on the concept of systemic security, where data links and network nodes are protected with a combination of stateful inspection, in-line blocking, and intrusion detection at the nine logical layers of the combined OSI Basic Reference Model and the GridWise Architecture Council (GWAC) Stack. The project utilized the standard smart inverter functions identified in the IEC 61850-7-520 and associated information model in IEC 61850-7-420. The DNP3 AN 2013-001 protocol will be used to support these functions for directly managed PV systems. The DNP3 protocol was used for the DMS connection to directly manage utility control devices (capacitors and voltage regulators).

The proposed DEHC approach was validated extensively through hardware-in-the-loop (HIL) simulations and field deployment. The DEHC architecture was tested at the Energy Systems Integration Facility (ESIF) at NREL in a Power HIL (PHIL) co-simulation (including software and hardware) environment that replicates real-world utility feeders with more than *10,000 virtual nodes.* All five features (a), (b), (c), (d), and (e) were tested. A part of the DEHC was demonstrated on utility feeders spanning a full substation in the Denver Metro area, due to constraints including lack of sufficient PV penetration in the field. The data and models from the field deployment were used to test and validate the entire DEHC architecture in NREL's ESIF. A cost-benefit analysis was also performed to quantify the cost and benefits of different approaches.

1 Project Objectives

The goal of the Eco-Idea project is to develop, validate and deploy a unique and innovative Data-Enhanced Hierarchical Control (DEHC) architecture that comprehensively addresses the formidable challenges associated with proliferation of high penetration of distributed PV such as reverse power flows, transients from variability of PV systems, feeder load balancing, and voltage stability.

1.1 Technical Work Plan

The technical scope comprehensively includes the following intertwined activities: 1) DEHC Architecture Design; 2) development of HIL test plans 3) Execution of HIL test plans; 4) Field demonstration; and 5) Cost-Benefit Analysis. The technical scope of the project was divided into three budget periods. In budget period 1 the team designed and developed a systematic approach of the coordination among the features mentioned in the project overview section to realize the proposed DEHC architecture. The team also developed the HIL test plans to succinctly validate the capabilities of the developed architecture in preparation for the budget period 2 scope. In budget period 2 the team executed the test plans to validate the proposed DEHC architecture in HIL environment at ESIF laboratory including validation of all the features mentioned in the project overview section above. In budget period 3 the team performed field deployment and demonstration of the DEHC architecture using the 1, 2 and 4 features and also performed a cost-benefit analysis of the deployment scenarios and use cases to demonstrate the benefit of the new architecture.

1.2 Milestones

The following milestones were planned and achieved:

- Milestone 1.1.1: Successful selection of feeders that include 10,000 virtual nodes and 100 physical controllable nodes from the utility partner territory.
- Milestone 1.2.1: Successful development of DEHC architecture to meet the ENERGISE goals and enable a penetration level of solar energy beyond 50% relative to the peak load, beyond 125% relative to daytime minimum load, and greater than 20% by annual energy production.
- Milestone 1.2.2: Successful development of DEHC architecture to meet the ENERGISE goals and enable a penetration level of solar energy beyond 50% relative to the peak load, beyond 125% relative to daytime minimum load, and greater than 20% by annual energy production.
- Milestone 1.2.3 Deliver the specifications defined for the interface between grid-edge head-end server and ADMS.
- Milestone 1.3.1 Successful development of cybersecurity and interoperability plans.
- Milestone 1.3.2 Successful development of the communication interfaces for DEHC architecture.
- Milestone 1.3.3 Successful completion of milestones 1.1, 2.3.1, 2.4.1, 2.1, 3.1.1, 3.2.1, 4.1 and 5.1.
- Milestone 1.4.1: Complete test plans for laboratory HIL testing, cybersecurity, and interoperability evaluation of the DEHC.
- Milestone 1.5.1: Establish Industry advisory board approved by DOE

- Milestone 2.6.1: Successful Grid-Edge Head-End Server/ADMS interface demonstration
- Milestone 2.7.1: Successful functional testing of DEHC architecture using representative field models (models of the selected utility feeders and grid-edge devices) and data (SCADA data and AMI measurements) in the HIL simulation environment.
- Milestone 2.7.2 Successful cybersecurity assessment of the DEHC architecture in the lab.
- Milestone 2.7.3 Successful interoperability assessment of the DEHC architecture in the lab.
- Milestone 2.8.1 Successful field deployment of ADMS technologies, grid-edge devices and other hardware.
- Milestone 2.8.2 Successful development of test plans for testing DEHC architecture in the field.
- Milestone 2.9.1: Complete the dissemination of Interoperability and technical laboratory results to the broader stakeholders through workshop and incorporation of the outcome in industry standards.
- Milestone 2.9.2: Complete the dissemination of Interoperability and technical laboratory results to the broader stakeholders through workshop and incorporation of the outcome in industry standards.
- Milestone 3.10.1: Successful field demonstration of the DEHC architecture in the utility partner's feeders.
- Milestone 3.10.2 Successful data collection from field tests.
- Milestone 3.11.1: Complete analysis of the technical benefit for the DEHC architecture.
- Milestone 3.11.2 Complete analysis of the economic cost-benefit for the DEHC architecture assessing the value and benefits of the DEHC architecture against the industry standards through analysis of field results.
- Milestone 3.12.1 Complete the dissemination of technical and economic analysis to the broader stakeholders through workshop and incorporation of the outcome in industry standards.
- Milestone 4.10.1 Successful analysis comparing feeder performance with PV control against baseline

2 Project Results and Discussion

2.1 Task 1.0 Select Utility Distribution Feeders

Selection of the utility distribution feeders on the Xcel Energy network was finalized to be the following:

1. Substation 1, which has 4 feeders, 32 controllable devices (capacitors/reclosers), 153 existing Varentec ENGO units.

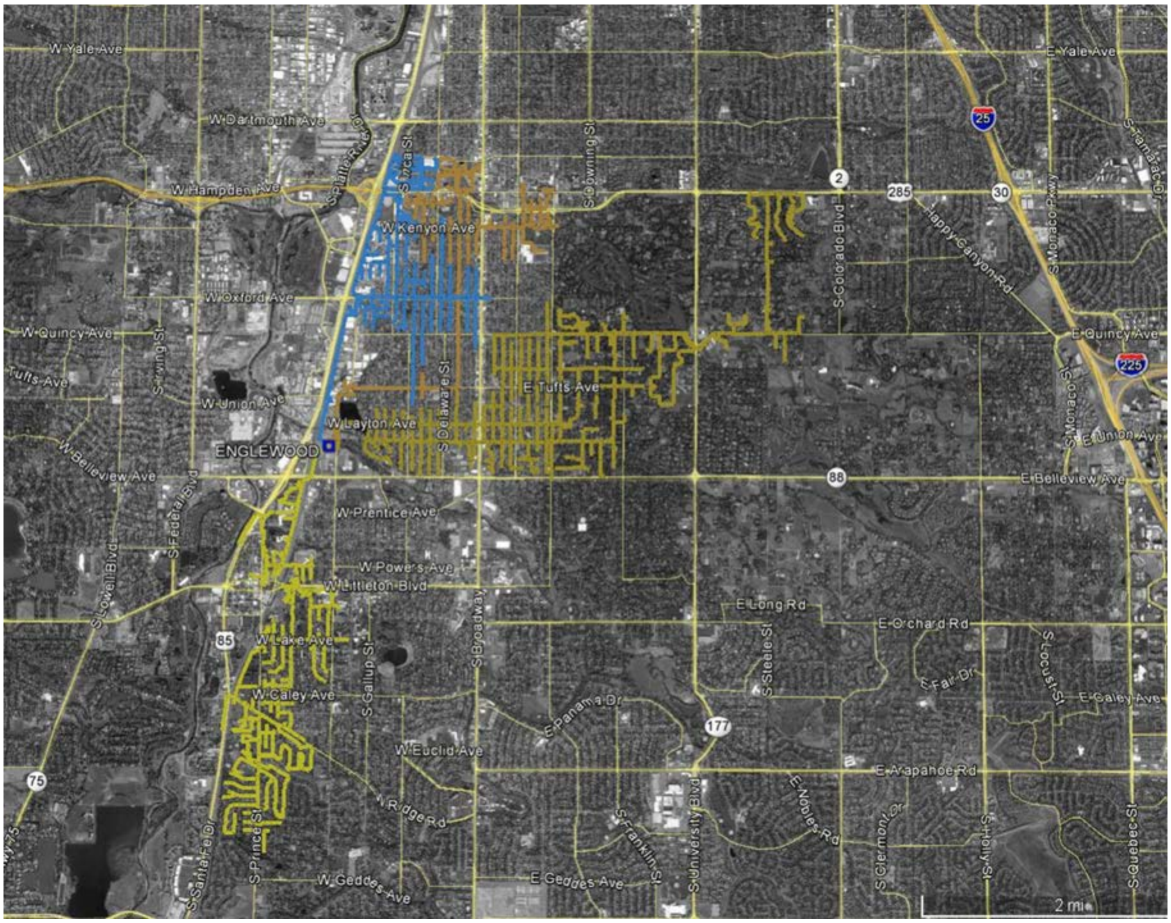


Figure 2. Map of Substation 1

2. Substation 2, which has 5 feeders, 18 controllable devices (no voltage regulators), no existing ENGO units. Load/customer characteristic similar to Substation 1 with 25-30MW loading.

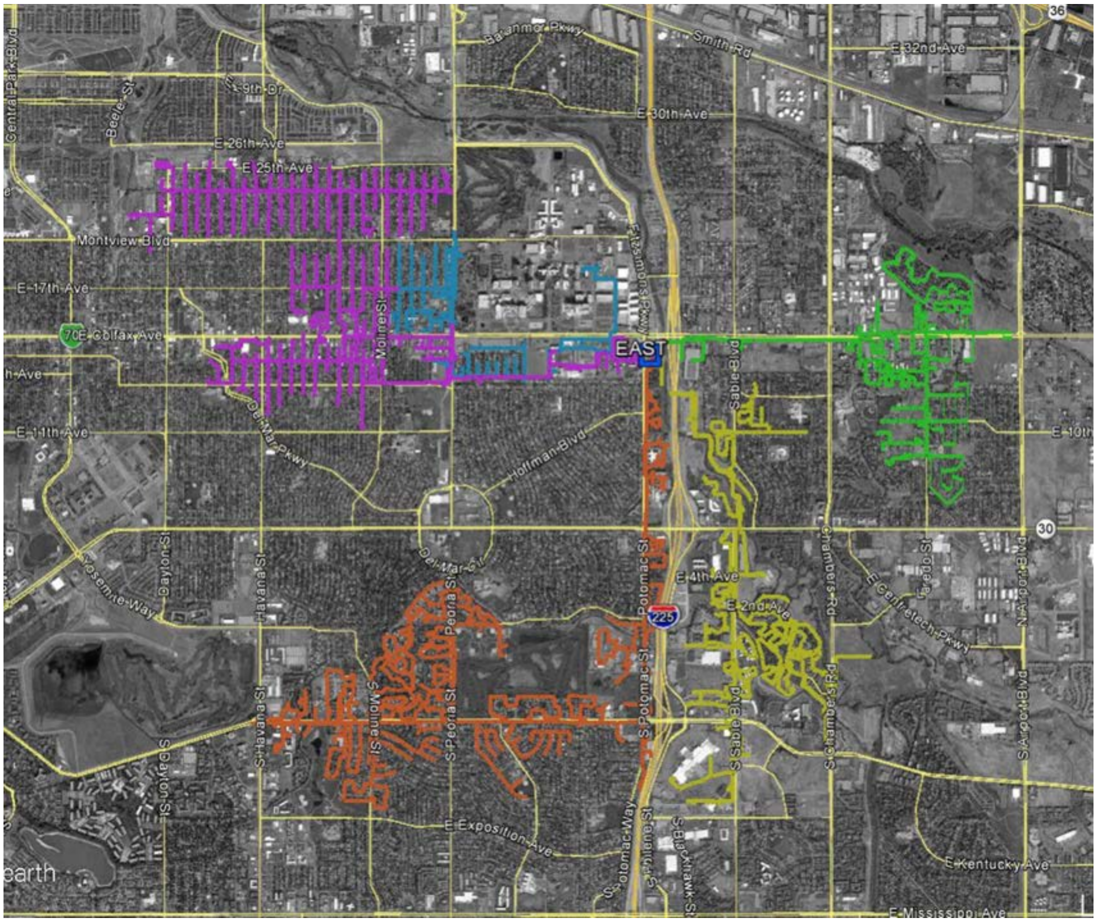


Figure 3. Map of Substation 2

2.2 Task 2.0 Develop DEHC Architecture

2.2.1 Subtask 2.1: Design and Develop DEHC Architecture

The DEHC architecture is composed of three essential parts, including NREL's distributed PV inverter control based on real-time optimal power flow (RT-OPF)[4], Varentec's grid edge device (ENGO model), and Schneider's ADMS volt-var-watt optimization (VVWO). Based on the internal power flow model and real-time SCADA data acquired from the field, ADMS VVWO generates the set points for controlling legacy control devices (LTC, voltage regulator and capacitor bank), provides voltage setpoint signals for ENGO devices, and optionally provides control reference signals for RT-OPF. Grid edge device, i.e. ENGO, determines its reactive power injection into the distribution feeder based on the voltage setpoint signals received from ADMS, in order to support secondary voltage. RT-OPF solves the optimal active power and reactive power setpoints for all controlled PV inverters, in order to reduce voltage violation and improve power quality. Three control time scales exist in the DEHC architecture: 1) slow timescale (such as 15 minutes) – the ADMS controls legacy voltage regulating devices including capacitor switching and regulator tap positions on a slow timescale; 2) moderate timescale (such

[4] RTOPF reference

as 10 seconds) – the RT-OPF can solve the optimal setpoints for PV inverters every second, but considering the reasonable communication requirement, we propose to use RT-OPF to control PV inverters every 10 seconds; 3) fast timescale (1 second) – the reactive power output from ENGO devices at grid edge are adjusted every second.

To evaluate the DEHC architecture, analytical simulations were performed in the past quarters to study both feasibility and performance for the DEHC architecture using a co-simulation framework. As shown in Figure 4, the co-simulation framework is developed using Python language and OpenDSS[5] software simulation, and coordinates with Schneider's ADMS software, Varentec's ENGO device model and NREL's RT-OPF. The common information models (CIM) of the selected Xcel distribution feeders were received from Xcel, and NREL has converted these models into OpenDSS format to conduct advanced power flow analysis. ENGO devices are modeled by Varentec using a DLL file and it is integrated into the converted Xcel feeder model built in OpenDSS. The RT-OPF is developed and modeled using Python language by NREL. Also, a python wrapper is developed to manage the operations and data exchange for all components in the co-simulation framework, which is responsible for:

- Read control signals from ADMS and send these data into the OpenDSS model, ENGO.DLL model and RT-OPF.
- Update OpenDSS model (include ENGO .DLL model) based on the control signals received from ADMS.
- Extract system model information (Ymatrix, load and PV data) and power flow results from OpenDSS model simulation and send such information into RT-OPF.
- Activate RT-OPF to solve the optimal power setpoints.
- Read power flow results from OpenDSS feeder model and send data back into ADMS as SCADA measurements.

[5] http://smartgrid.epri.com/SimulationTool.aspx

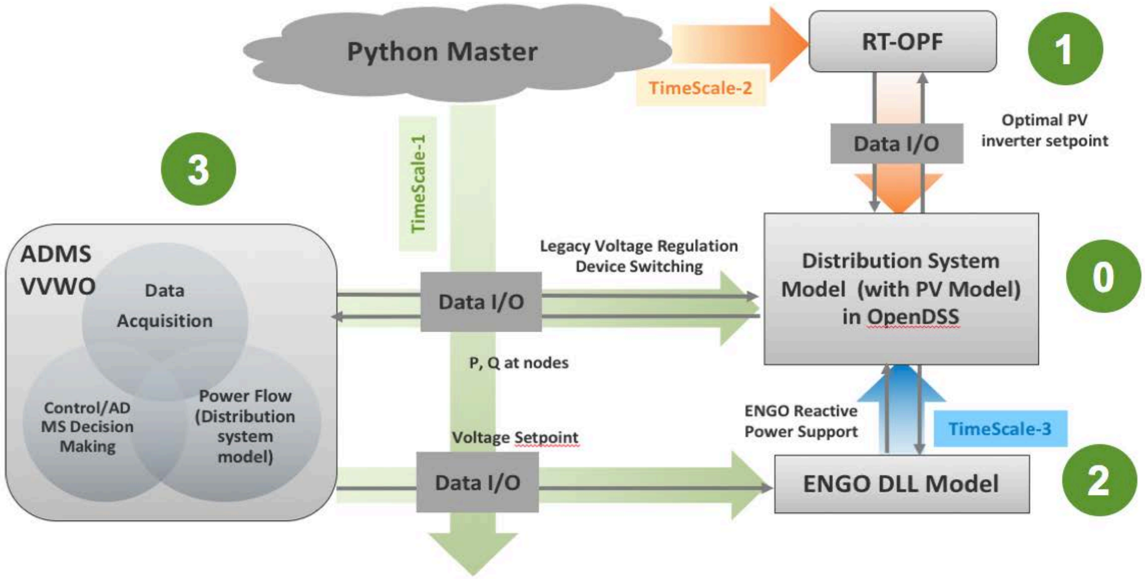


Figure 4. Co-simulation framework of the DEHC architecture

2.2.2 Subtask 2.2: Enhance and Configure ADMS Product Modules

SE-ADMS Volt-Var Optimization (VVO) is an integrated solution that manages voltages and reactive power flows in the distribution network. The application determines optimal Volt-Var strategy to achieve the specified operating objective within the operating constraints.

The proven benefits of VVO usage as offered by Schneider DMS are:

- Levelized voltage profile for all customers along a feeder,
- Substation VAR support, improved feeder power factor, and reduced line losses,
- Conservation Voltage Reduction (CVR) – energy savings,
- Demand reduction – peak load shaving,
- Fast voltage reduction during emergency conditions – avoiding load shedding.

For calculating the optimal state, VVO supports both a model-based approach that bases its decisions on the estimated actual network state and rule-based approaches that only rely on the ordering of devices to be controlled.

The value of an ADMS-VVO model-based solution is that all decisions are based on the current state of the network instead of some assumed state. The initial state for the VVO calculation is the current "as operated" network state with actual statuses and parameters of all control devices. In this way, the result of the VVO calculation achieves a network state 'better' (from the point of view of optimization objective) than the current one, with minimal execution time (minimal number of switching operations).

Depending on the final goal, the VVO can be stated as a simple optimization problem, with one objective only, but also as a very complex optimization problem, with several, sometimes contradictory objectives. The complexity of the problem lies in the fact that the solution of the considered problem depends on both planned and unplanned factors e.g.: loads depend on network voltages, loads and network topology vary in time, power losses depend on loads and network voltages, local automation significantly affects the problem, the value of real power injected in the distribution network by distributed generators depends on control laws which are applied on the considered distributed generators.

DNP3 is the communication protocol used among ADMS and other components (except RT-OPF) in the DEHC architecture for software simulations. To enable the communication between Schneider's DMS and OpenDSS model, NREL developed a gateway-based approach, described as Figure 5, to translate DNP3 signals to raw socket TCP/UDP and vice versa. NREL had worked closely with Schneider team to fix all ADMS model issues and communication challenges, and finally has successfully enabled the communication between OpenDSS and ADMS.

Figure 5. Proposed gateway-based approach to translate DNP3 signals to raw socket TCP/UDP to enabled communication between ADMS and OpenDSS

2.2.3 Subtask 2.3: Characterize Grid-Edge Devices and Integrate the Models Into the System Simulation

The grid edge device model, i.e. ENGO, is built using a .dll file which can control its reactive power injection into the feeder based on the local voltage measurements. Below shows the screenshot of one ENGO model that is built inside OpenDSS for DEHC architecture. A single ENGO model can alter its reactive power generation from 0 to 10 kVar with 1 kVar step change. Figure 6 shows an example of variable reactive power generation from eight ENGO models.

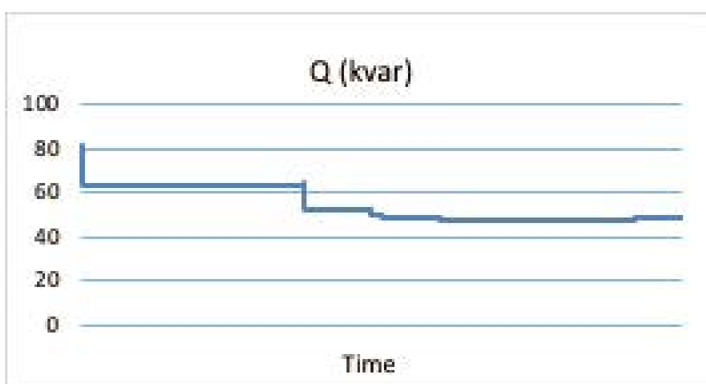


Figure 6. Variable reactive power output from eight ENGO models

One of the feeders from Task 1 is used to study the grid impact of ENGO devices. This selected feeder has the largest number of ENGO devices installed in the field, and Figure 7 shows the locations of all 67 ENGOs. The voltage profiles of no ENGO (baseline) and with ENGO scenarios are obtained as Figure 8, and it shows that the existence of ENGO devices will boost voltages around the ENGO locations.

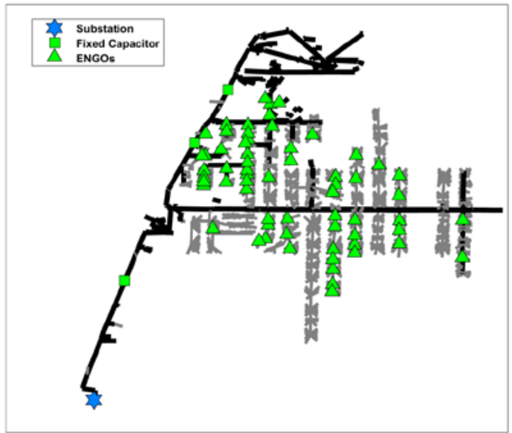


Figure 7. Locations of ENGO devices in feeder

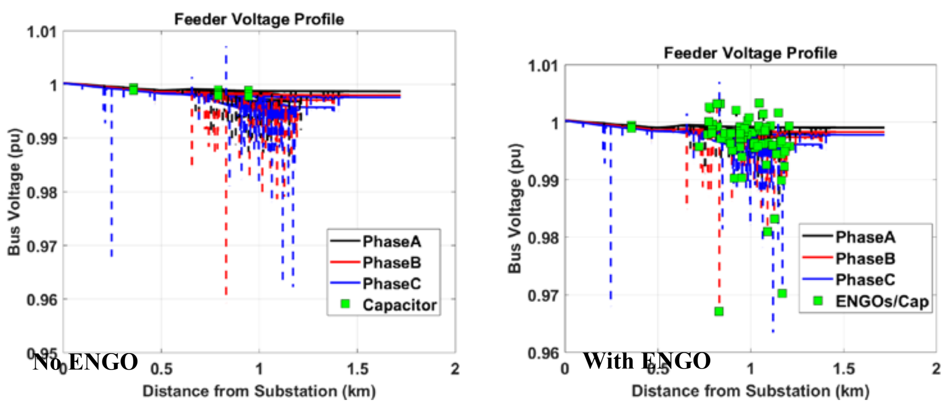


Figure 8. Voltage profiles for no ENGO scenario and with ENGO scenario

Besides, the performance of ENGO devices for one-day simulation is provided in Figure 9. In general, ENGO will help boost secondary circuit voltage, and it can alter its reactive power output to make voltage stay around 120 V.

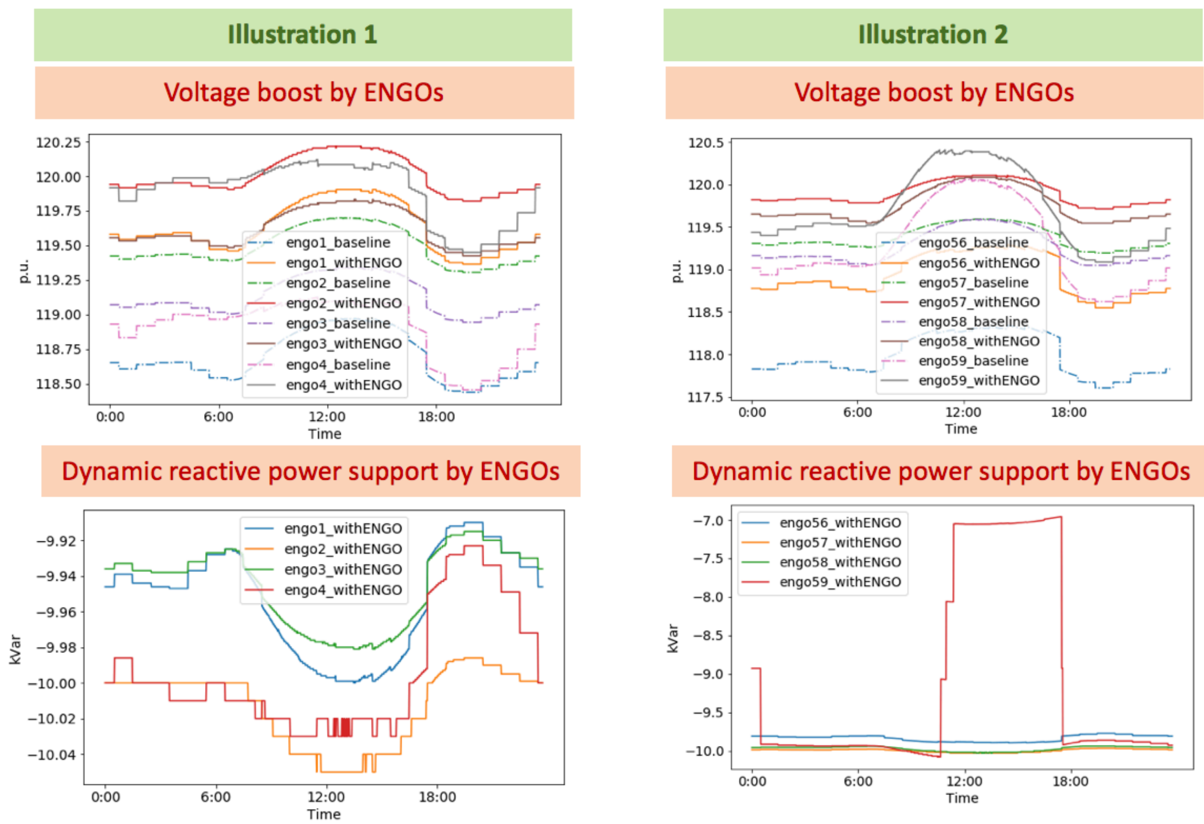


Figure 9. One-day reactive power output and terminal voltages for the ENGO devices

2.2.4 Subtask 2.4: Define Specifications for Interface between Grid-Edge Head-End Server and ADMS

Varentec and Schneider Electric has completed the development of the DNP3 specification between Varentec's GEMS and SE's ADMS. The development of the actual DNP3 interface between GEMS and ADMS was also completed and tested. Finalized specification and test documents were submitted in an independent submittal to DOE.

Varentec has also developed the CIM interface functional specification. This document is included as part of this quarterly report submittal. This CIM interface specification document describes a high level and conceptual framework for a CIM based interface between GEMS and ADMS. The purpose of this interface is to exchange voltage and setpoint information and provide GEMS with a mechanism to update its electric model based on permanent and temporary circuit reconfiguration.

2.2.5 Subtask 2.5: Develop Distributed PV Inverter Control

NREL had developed the real-time OPF algorithm for the DEHC architecture to control PV inverters in a distributed manner. Figure 10 shows the framework for implementing the feedback-based, distributed RT-OPF control. All red circles represent the measurement units in the field system, where voltage measurements can be obtained. The coordinator gathers voltage measurements from the field (OpenDSS power flow results in the co-simulation framework) and broadcasts these global measurements into all PV controllers. Each controller is solving the optimal active and reactive power setpoints for the individual PV inverter based on its own objective function, which is to minimize active power curtailment and reactive power output while not violating voltage limitation based on ANSI limits (0.95-1.05 p.u.). There is no communication required among multiple controllers, and the computation at each controller is conducted independently.

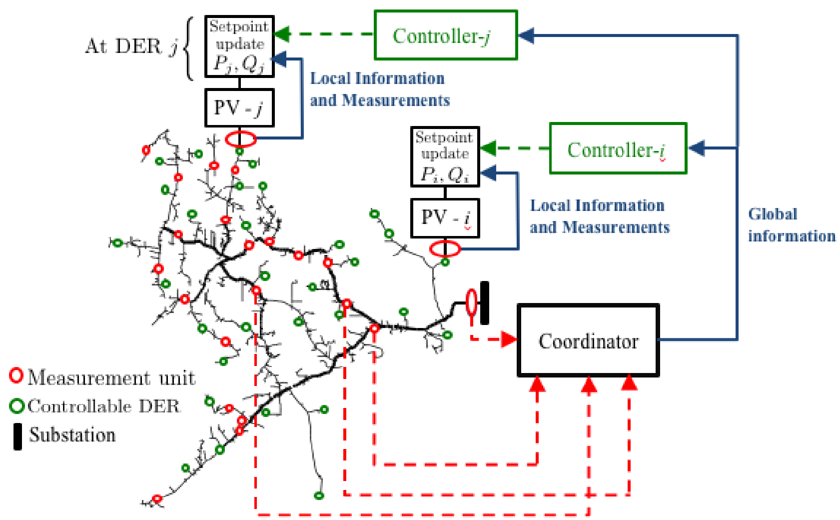


Figure 10. Framework for implementing the proposed RT-OPF for PV inverter control

Figure 11 shows the operation logic for implementing the RTOPF to control distributed PV inverters. The simulation results provided below are using 10-second as the control granularity. We compared the results between no RTOPF and with RTOPF scenarios for maximum feeder voltage, voltage profile at one time snapshot, total active power and reactive power generated from all PV inverters, and individual PV inverter power output. The results obtained for clear day and solar intermittent day are provided separately.

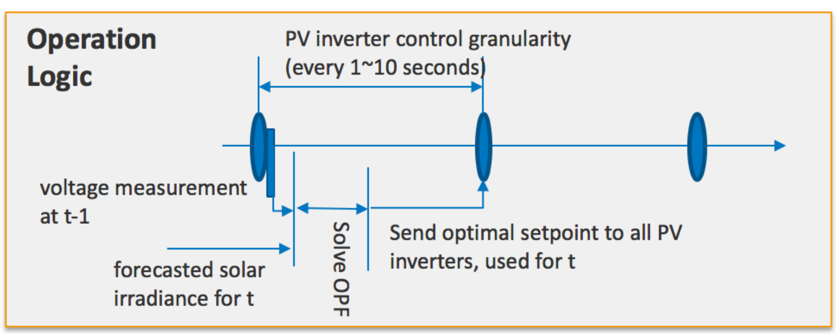


Figure 11. Operation logic for implementing RTOPF to control distributed PV inverters

Figure 12 shows the maximum voltage results respectively obtained for the baseline (no RTOPF) and the scenario with RTOPF. The implementation of RTOPF can significantly help eliminate overvoltage problems caused by high PV penetration. Figure 13 shows the single time snapshot voltage profile obtained for the baseline (no RTOPF) and the scenario with RTOPF. The implementation of RTOPF helps solve the overvoltage occurring at the node that is 1.3 km far from the substation.

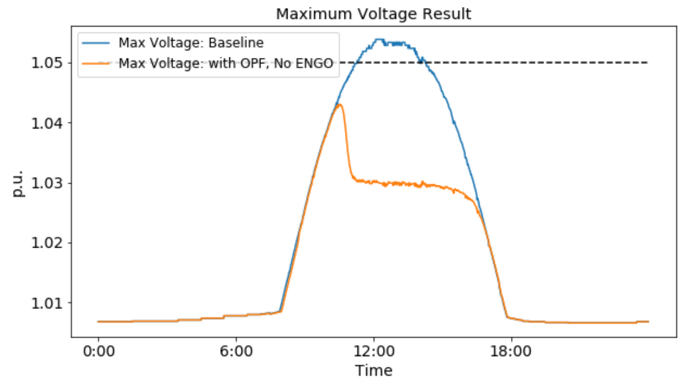


Figure 12. Maximum feeder voltage for the clear day

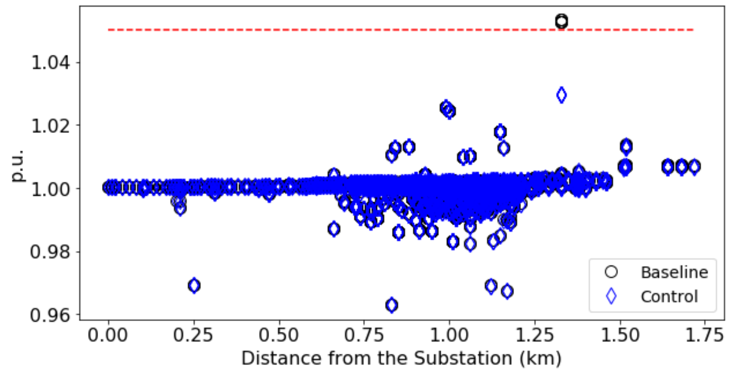


Figure 13. Voltage profile for a selected time snapshot (clear day)

Figure 14 shows total active power and reactive power outputs from all controlled PV inverters. Without RTOPF there is no reactive power output from PV inverters since all inverters are operating under unity power factor. Instead, the implementation of RTOPF will ask PV inverters to absorb reactive power to reduce voltage. Because the sizes of all PV inverters are same as their maximum active power output, a slight curtailment in PV active power is needed to provide headroom for reactive power.

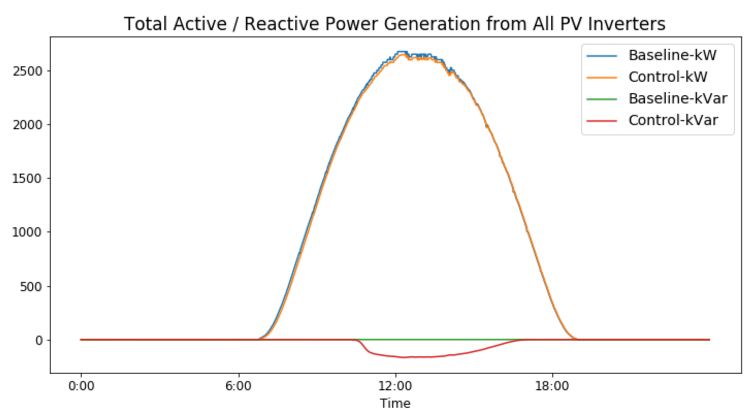


Figure 14. Total active power output and reactive power output from PV inverters for the clear day

2.3 Task 3.0 Ensure Cybersecurity and Interoperability of DEHC Architecture

2.3.1 Subtask 3.1: Develop Cybersecurity and Interoperability Plans

The interoperability and cybersecurity plans covered the design and validation of information exchange between the different components of the Data-Enhanced Hierarchical Control (DEHC) architecture. The test plans were submitted to the DOE as separate documents. The scope of these plans is shown in the figure below.

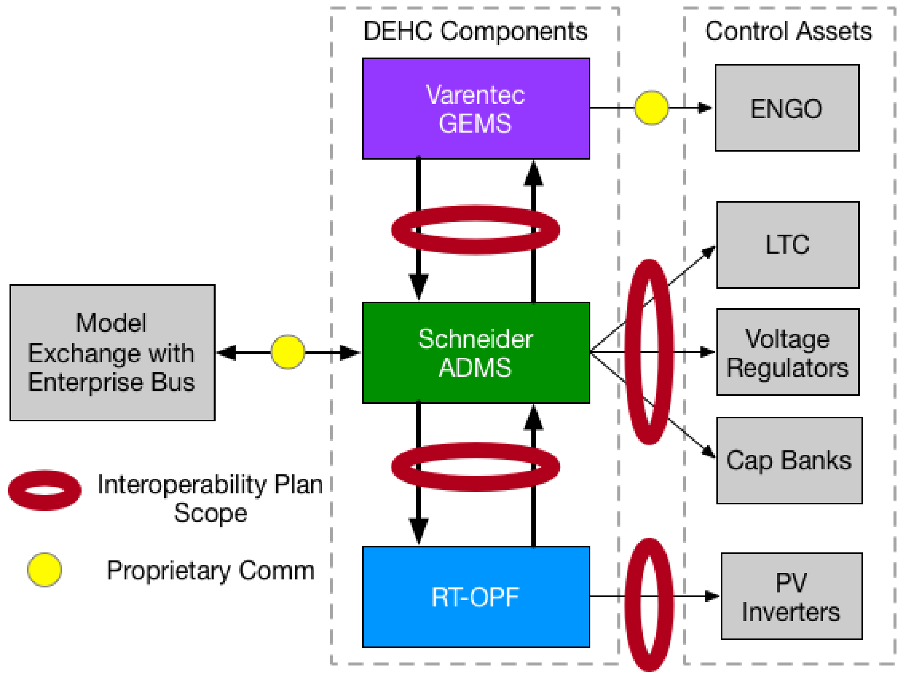


Figure 15. Interoperability and cybersecurity plans in the DEHC architecture

2.3.2 Subtask 3.2: Adopt Layered Cybersecurity Architecture for Systemically Securing Power Systems

The proposed layered defense approach for securing the DEHC architecture is presented in the figure below.

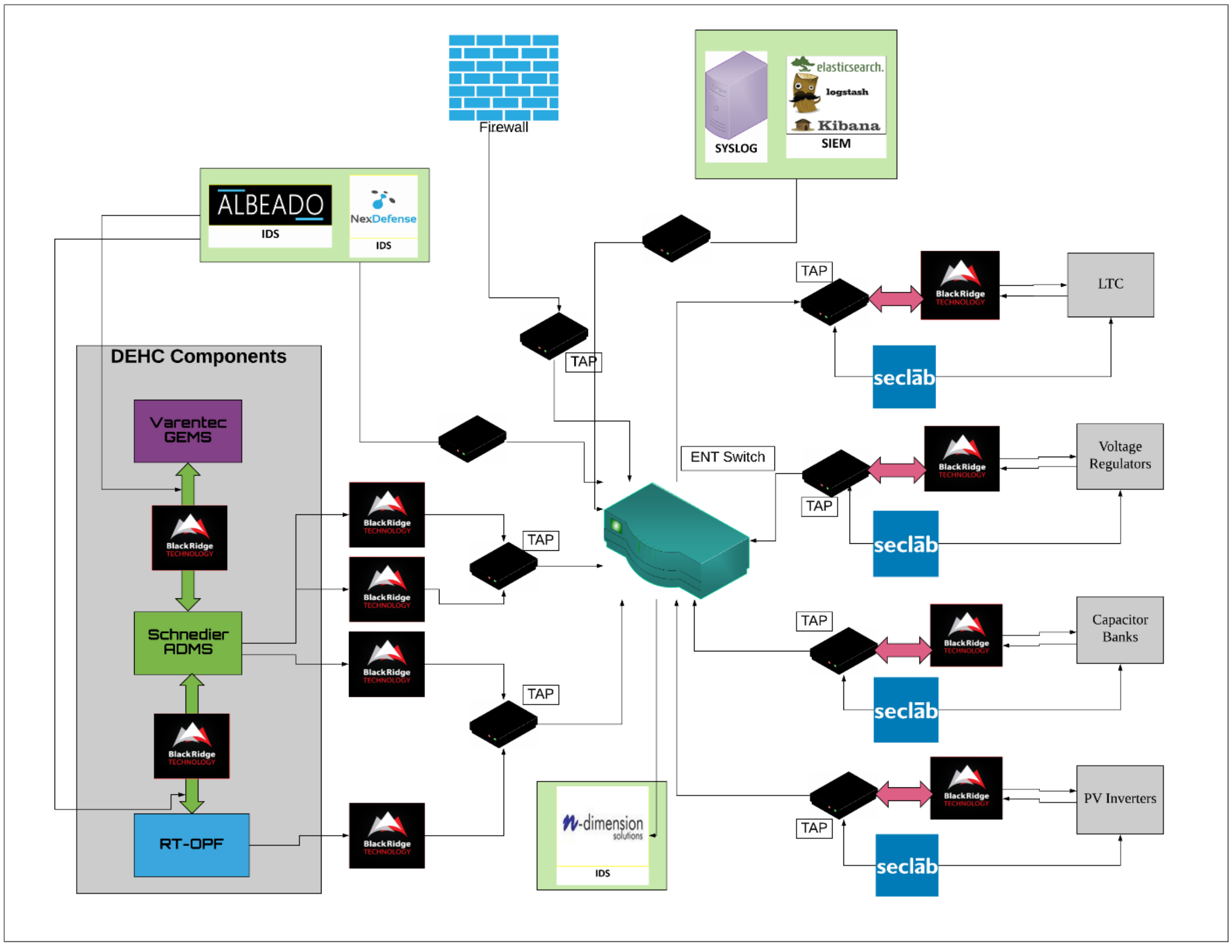


Figure 16. Layered defense approach employed for securing the DEHC architecture

The layered cybersecurity plan for securing the DEHC architecture includes the following features:

1. Bump in the wire security solution was identified using purpose-built cybersecurity technologies to protect the mixture of legacy and modern systems in critical infrastructure right off the bat and relieve the application devices from facing the brunt of the emerging threats and the stringent security controls that they are not equipped to handle. This bump in the wire security comes in the form of cutting-edge intrusion detection and in-line blocking technologies that are aware of anomalies in protocol transactions at all the logical communications layers (OSI stack + Semantic + Business Process layers) and can jointly alarm and block when the anomalies can disrupt the application at any logical layer. These technologies can have their firmware easily upgradeable to address new threats quickly and cost effectively while preserving the devices that support the actual critical infrastructure application until the end of their effective product life.
2. Network segmentation implemented by enforcing access control lists on switches and routers to limit the attack surfaces for hackers and role-based access controls will be implemented at the firewalls to provide effective segmentation in coordination with access control lists on the switches and routers without forcing the application devices to support these resources intensive security controls.

3. Most sophisticated username and password will be used for each application device to protect login privileges to hackers that have physical access to the devices. Also disabling all the unused ports on routers and switches and apply port security on ports that are in use to avoid unauthorized network intrusion to limit attack surfaces. Last, but not least, applying the latest versions of software security patches on all devices that have this feature to limit cyber vulnerability.

The different technologies used in the layered defense approach described above are presented as follows:

1. **N-Dimension (product name is N-Sentinel):** The N-Sentinel IDS is used to monitor data traffic between the enterprise switch and the field devices that will be in the OT network. It can detect known SCADA malware trying to infect the OT network nodes (field devices) in the enterprise site. As soon as the N-Sentinel IDS detects the malware and identifies its source, the OT network administrator can disable the compromised power systems node from the field OT network and protect the substations and enterprise from further cyberattacks from this source.
2. **The Albeado (product name is PRISM):** Albeado is used to provide Business Process Security. It monitors traffic going between the ADMS and field devices. If the hacker attempts to fuzz the power systems device data, the PRISM will detect the anomaly between the outgoing message from the ADMS to field device and the incoming message from the compromised field device and report it Syslog Server. The OT network administrator can reject the compromised power systems node in the field OT network and protect the system from further data fuzzing cyberattacks from this hacker.
3. **The Blackridge (product name is TAC):** It is an in-line blocking tool and is used to protect all the communication between ADMS or RT-OPF and Field devices from Denial of Service (DoS) attacks with a throughput capacity of 10 GB/s. This will be sufficient protection against this type of DoS attack in both substations and field networks.
4. **NexDefense (product name is INTEGRITY):** If any trusted node in the network is compromised by the hacker and used as a pivot for further attacks it will be detected by NexDefense integrity because the external IP address of the hacker will be visible in the NexDefense Integrity software network visualization tool and the type and quality of data traffic will not be consistent with the power systems use cases running between the ADMS and field devices. The OT network administrator can reject the compromised power systems node from the field OT network and protect the network from further cyberattacks from this hacker

2.3.3 Subtask 3.3: Develop Communication Interfaces

The following communication links were developed as part of the DEHC architecture:

1. Communication between Schneider ADMS and Varentec GEMS
2. Communication between Schneider ADMS and RT-OPF Module
3. Communication between Schneider ADMS and the field control assets
4. Communication between RT-OPF Module and field control assets

The following interactions are proprietary to the vendors:

- Communication between Varentec GEMS Head-end Server and the ENGO devices

- Communication between Schneider ADMS and the Enterprise bus for exchanging models

2.3.3.1 Communication between Schneider ADMS and Varentec GEMS

The Schneider ADMS and Varentec GEMS controls are decoupled by time scale of operations and by the control devices used for meeting the voltage objectives. The ADMS and the GEMS operate on 15-min time scales, while the ENGO devices operate at the rate of a few milliseconds. While the ADMS controls traditional voltage control devices such as capacitor banks, voltage regulators and Load Tap Changers (LTC), the GEMS exclusively controls ENGO devices.

The ADMS and GEMS will interface with each other through DNP3 at the rate of 15 minutes. For this interface, the ADMS will act as the DNP3 master and the GEMS as the DNP3 slave. GEMS will provide the voltage and VAR levels at each ENGO installation point in the feeder as well as data for each control zone. This interaction is shown in the figure below.

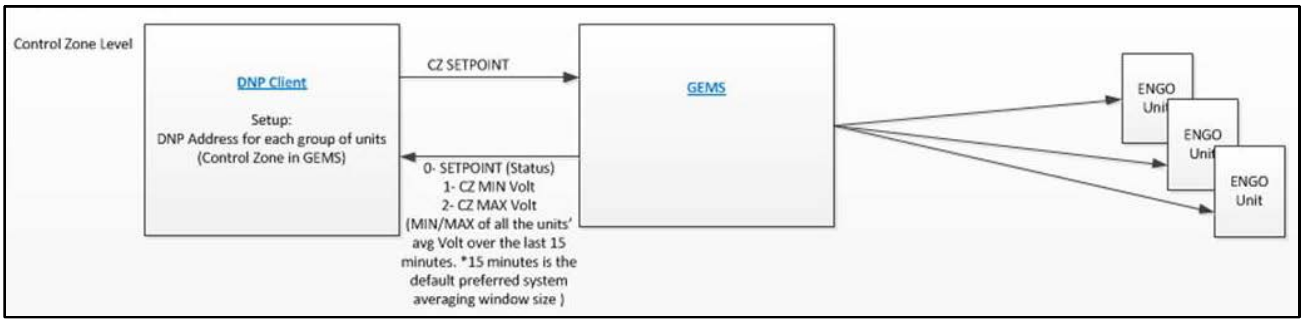


Figure 17. Interface between Schneider ADMS and Varentec GEMS controls

The table below lists the information exchanged between the Schneider ADMS and the Varentec GEMS, the exchange rate and the trigger for exchange, if any. Given that the ADMS and GEMS operate at different time scales through different control devices, explicit information exchange between the two systems is minimal. There are multiple local controllers, both primary and secondary (LTC, LVR, Cap Banks, ENGO) that the ADMS could use to alter voltage and reactive power upstream e.g. by operating cap banks and LVRs. GEMS, by providing local voltage and VAr information, helps ADMS to ascertain that those operations took place as planned.

Table 1.

Information Exchanged	Exchange Trigger	Exchange Rate	Protocol	Direction
Current set points, average minimum and maximum voltage	Polling	15 min	DNP3	GEMS to ADMS
New set point	Polling	15 min	DNP3	ADMS to GEMS

2.3.3.2 Communication between Schneider ADMS and RT-OPF

The ADMS and RT-OPF operations are decoupled by time scale of operations and to some extent by the devices being controlled. The RT-OPF is designed to control the PV inverters, behind-the-meter. The ADMS will also be configured to control PV inverters in addition to traditional voltage control devices. The ADMS will communicate the PV inverter set points to the RT-OPF on 15-min intervals. The RT-OPF will calculate new set points in the neighborhood ADMS-issued set points at the rate of 1 second to the PV inverters being controlled. Thus, the ADMS will provide coarse set points, while the RT-OPF will make finer adjustments to these set points for a tighter voltage control.

Table 2.

Information Exchanged	Exchange Trigger	Exchange Rate	Protocol	Direction
PV inverter set points	Polling	15 minutes	DNP3	ADMS to RTOPF

2.3.3.3 Communication between Schneider ADMS and the Field Control Assets

Schneider ADMS will use measurements collected by its SCADA application, and exercise control on the field control assets through SCADA as well. The field control assets will consist of traditional voltage control devices and PV inverters. The communication will happen through the DNP3 protocol.

Table 3.

Information Exchanged	Exchange Trigger	Exchange Rate	Protocol	Direction
Set points	None	Every 15 minutes (ADMS control time period)	DNP3	ADMS to voltage regulators, LTCs, capacitor banks
Measurements	None	Every 15 minutes (ADMS control time period)	DNP3	Field devices to ADMS

2.3.3.4 Communication between RT-OPF Module and PV inverters

The RT-OPF module will send control set points to Behind-the-meter (BTM) PV inverters through the DNP3 protocol. The RT-OPF module will interface with RT-OPF controller, which in turn will send control set points to the inverters.

Table 4.

Information Exchanged	Exchange Trigger	Exchange Rate	Protocol	Direction
P and Q set points for PV inverters	None	Every 1 second (RTOPF control period)	DNP3	RTOPF to PV inverters
Measurements	None	Every 1 second (RTOPF control period)	DNP3	PV inverters to RTOPF

2.4 Task 4.0: Define Test Plans for HIL Co-Simulation

The HIL test set up for evaluating the DEHC architecture at NREL's ESIF is presented in the figure below.

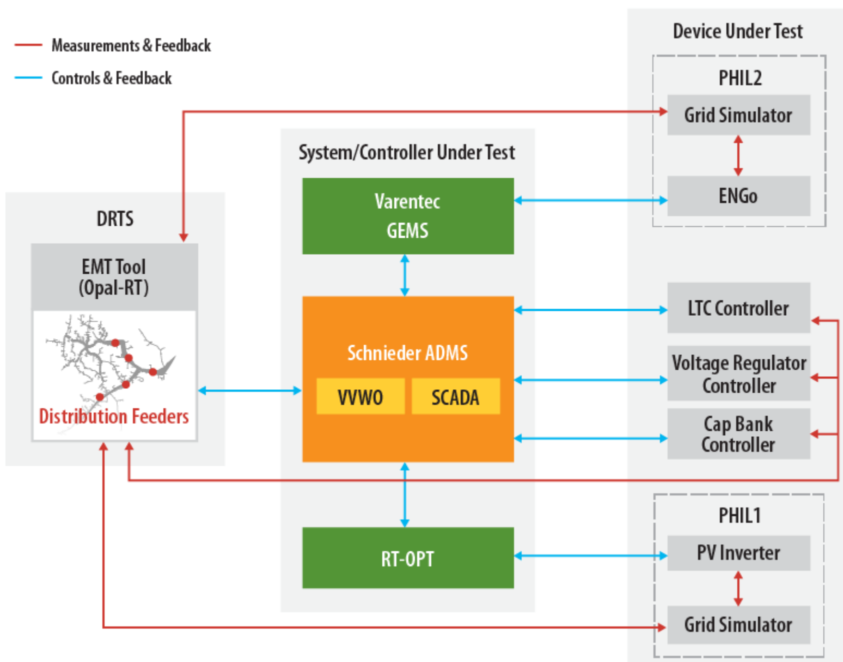


Figure 18. HIL test set up for evaluating the DEHC architecture at NREL's ESIF

The key parameters of the HIL set up is summarized in the following table.

Table 5.

DEHC Test Bed Use Case	
Use case	Develop, validate, and demonstrate a unique and innovative DEHC architecture to provide utility companies with a hierarchical yet unified solution to tackle the critical challenges associated with the coordination of the enhanced system layer, the traditional system layer, the telecommunications and data layer, and the local device and control layer.
Capabilities demonstrated	Integrate multi-vendor simulation platforms, multiple controller-hardware-in-the-loops (CHILs), multiple PHILs, the hierarchical control structure with coordinative control, the enabling tools for communication interfaces, and integrated data collection and management system.
Expected results	The HIL test will demonstrate that the DEHC control system can integrate extremely high levels of PV systems while maintaining voltages within limits and can provide futuristic ancillary market services, such as maintaining production reserve and reactive power support.
ADMS deployment	Xcel Energy feeders, Schneider Electric's ADMS with VVWO and SCADA applications
Test Setup	
Software simulation	The selected feeders will be simulated in Opal-RT's eMEGASIM in real time.
CHIL	Schneider's ADMS
	Varentec's GEMS control
	RTOPF
CHIL/software models (assets controlled by ADMS)	LTCs, capacitor banks, and voltage-regulator controllers
PHIL (controlled by GEMS)	ENGO devices
PHIL (controlled by RTOPF)	12-kW, three-phase SMA PV inverter
Communications	Between Schneider's ADMS and Varentec's GEMS
	Between Schneider's ADMS and the RTOPF
	Between Schneider's ADMS and the filed control assets (the traditional voltage controllers)
	Between Varentec's GEMS head-end server and the ENGO devices
	Between Schneider's ADMS and the enterprise bus for exchanging models
	Between the RTOPF and the PV inverters

2.5 Task 5.0: Disseminate Budget Period 1 Results and Transfer Technology

The first Industry Advisory Board (IAB) meeting for Eco-Idea project was convened on the sidelines of DistribuTech '18 conference at San Antonio on Jan 25, 2018. The IAB meeting was jointly organized with the IAB meetings for two ADMS-related projects led by NREL and PNNL. The IAB constituted for these two previous ADMS-related projects has been expanded to accommodate the broader scope of architecture and controls development and inclusion of grid-edge controls. The project was well-received by the IAB members. As the introductory meeting for the ENERGISE project, the session was focused on familiarizing the IAB members with the project scope and deliverables. The second IAB meeting was scheduled on April 17, 2018 on the sidelines of the IEEE PES T&D Conference in Denver, Colorado. The third IAB meeting was scheduled for July 24, 2018. This IAB is a webinar-style format held together with the ADMS Testbed and GridAPPS-D projects.

Additionally, NREL hosted a workshop on the ADMS Testbed development and capabilities, including showcasing of several ADMS-related projects including the Eco-Idea project. The workshop was well attended by partnering research entities (EPRI, ANL, and others) and industry organization (Xcel Energy, Duke Energy, Schneider Electric, Varentec, naming a few). The audience was very engaged and interested in the development and progress made in finalizing the architecture and simulation. The workshop Q/A/feedback was submitted for reference. In summarizing the research activities in BP1, project partner Varentec had also shared progress and plan in continued commercialization of their products and service offerings. Varentec's Commercialization Plan was also submitted to the DOE.

2.6 Task 6.0 Develop and Test Grid-Edge Head-End Server/ADMS Interface

The DNP3 interface between GEMS and ADMS systems at the respective partner locations was tested in BP1. Finalized specification and test documents (including outcome and results) were submitted to DOE. As part of this project, the DNP interface testing was performed with the Schneider ADMS and in conjunction with Xcel Energy and NREL. Three units were installed at NREL lab to serve as a test bed to pass data to the ADMS and receive voltage setpoint values from the ADMS.

Figure 19. *Photo by NREL*

A VPN Tunnel was set up between the NREL lab where the units reside and a GEMS instance at Varentec premises. The GEMS instance served as the DNP3 RTU/server for the ADMS. All tests defined in this document were successfully run and validated. They all passed with no errors:

- Read ENGO Data
- Read Voltage Control Zone Data
- Write/Read Voltage Control Zone Setpoint
- Error Handling

2.7 Task 7.0 Execute HIL Test Plans

The HIL experiments were executed by including different types of hardware including legacy system devices, grid-edge devices and PV inverters. These tests utilized the OPAL-RT platform for real-time digital simulations. The Xcel Energy distribution network was implemented using the ADMS Testbed capability at NREL, and Schneider Electric's ADMS, Varentec's GEMS and ENGO devices and NREL's RTOPF were deployed through realistic communication channels. This set up is shown in the figure below. Through the execution of HIL test plans, the proposed DEHC architecture was fully tested and validated, in preparation for the field deployment.

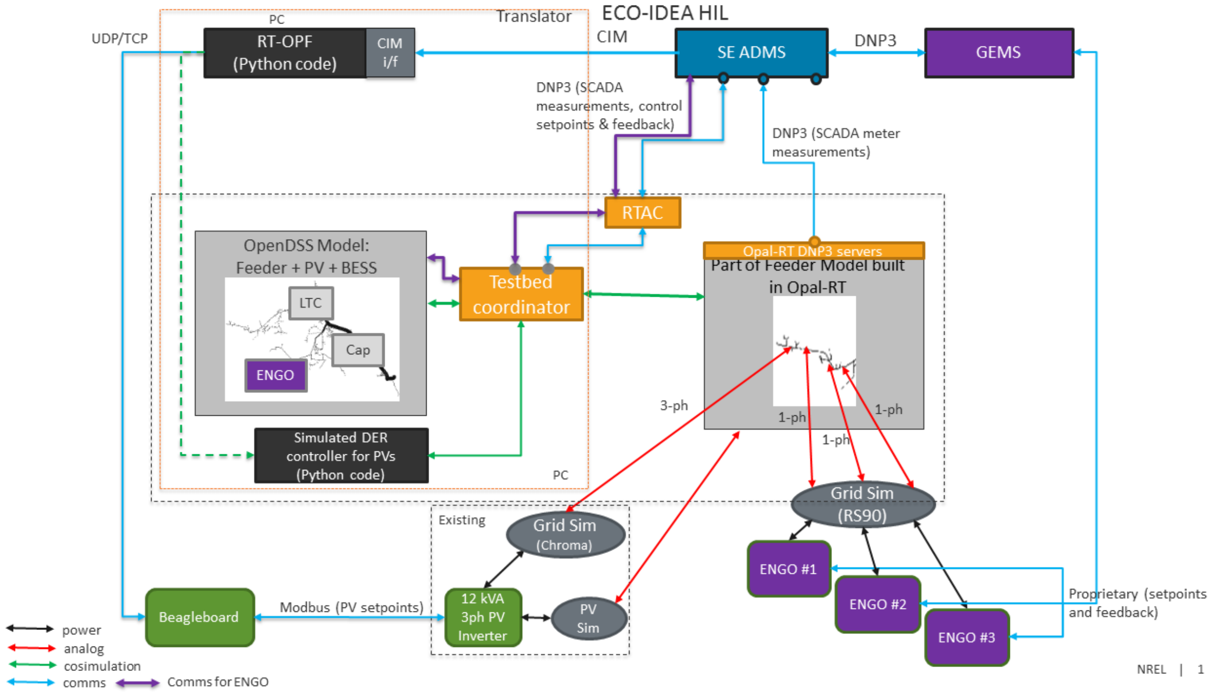
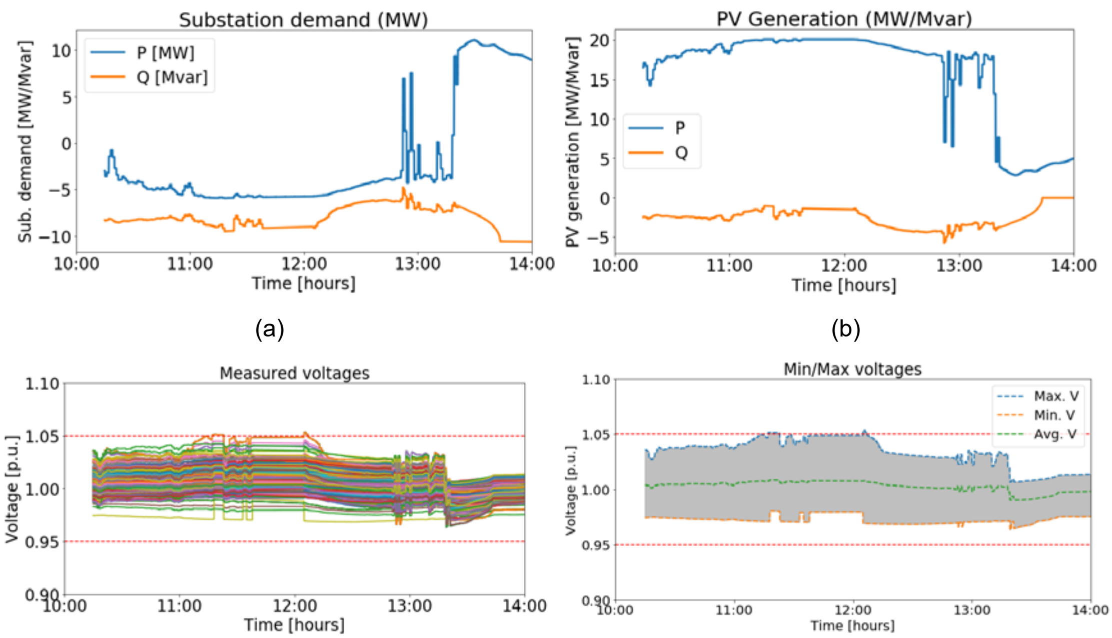


Figure 20. HIL test setup of ECO-IDEA

To verify the integrated test, we performed a 4-hour test from 10:00 – 14:00 to verify the ADMS-centered operation controlling legacy and grid edge devices and coordinate with RTOPF for voltage regulation under high PV scenarios using the HIL setup shown in Figure 20. The results are shown in Figure 21 to Figure 26 to verify capability of the integrated platform and performance of voltage regulation of the DEHC control system.

Figure 21 shows the system output, including substation active and reactive power, total PV generation, all measured voltage, and extreme voltages. The PV generation shows that PV has small amount of curtailment in active power and absorbs reactive power to maintain the voltage within limits during high solar irradiance period. The measured voltage and extreme voltage show that the system voltages are within the operation limits (0.95-1.05 p.u.). Therefore, this HIL test demonstrates that ADMS centered operation can regulate the system voltage within the operation limits and the HIL platform is capable of evaluating DEHC functionality of coordinated controls to achieve desired voltage profile.

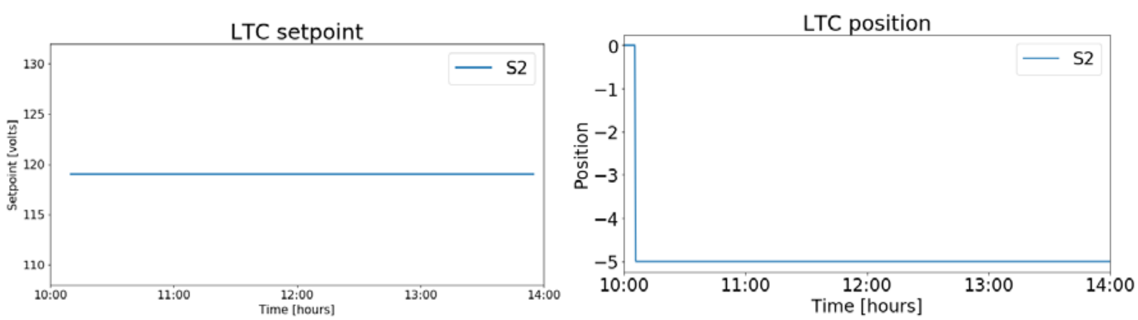


(a) (b)

(c) (d)

Figure 21. HIL test results: (a) substation active and reactive power, (b) total PV generation, (c) measured voltages, and (d) extreme voltages

Figures 22 thrrough 24 show the HIL test results of LTC, all capacitor banks and selected simulated ENGOs, which shows that ADMS gives priority to LTC to regulate system voltage before changing the commands for capcitor banks. The results also show that all these assets follow the commands/setpoints from ADMS correctly to collectively regulate the system voltage.



(a) (b)

Figure 22. HIL test results: (a) LTC setpoint from ADMS and (b) measured LTC tap position

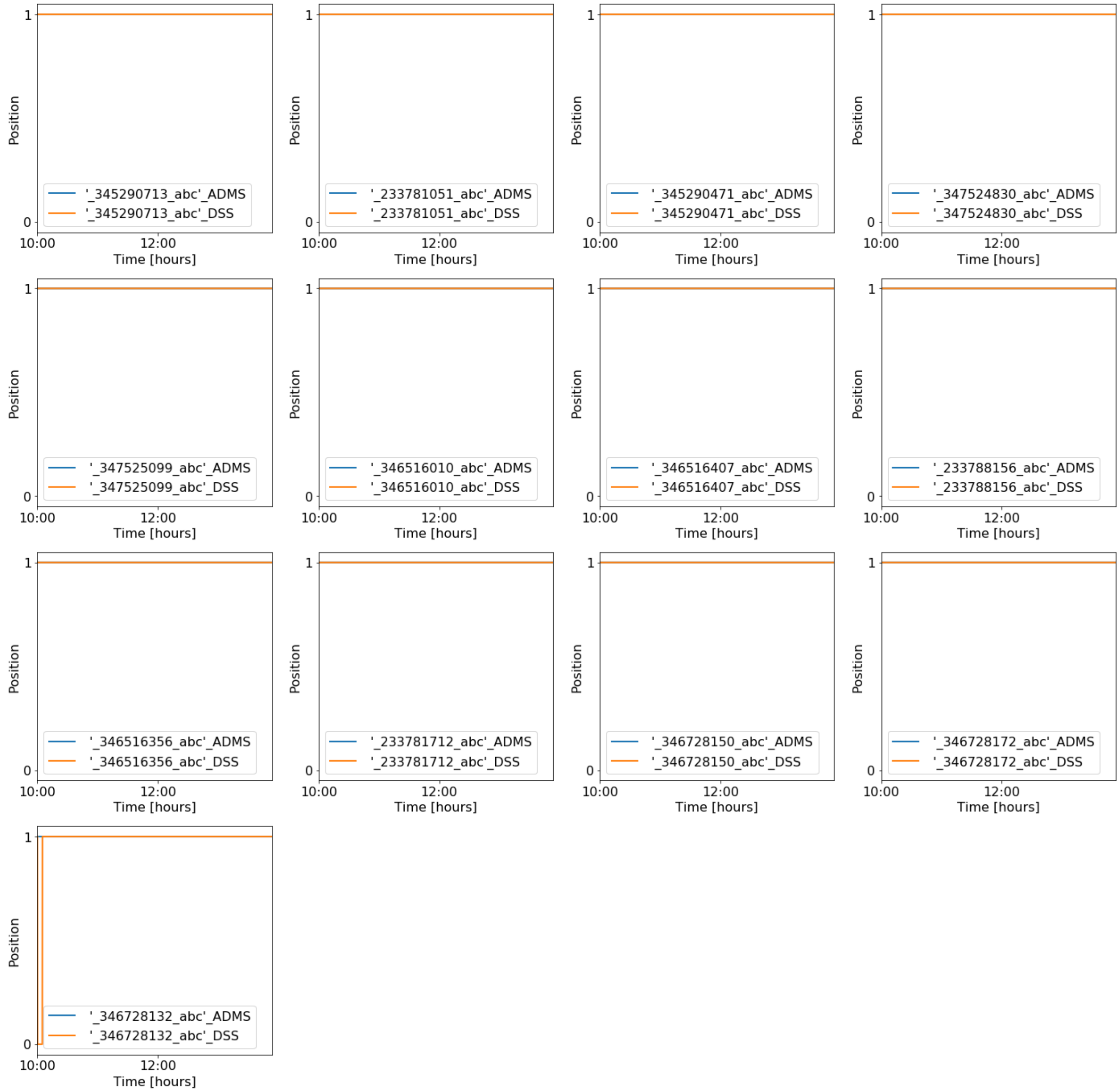
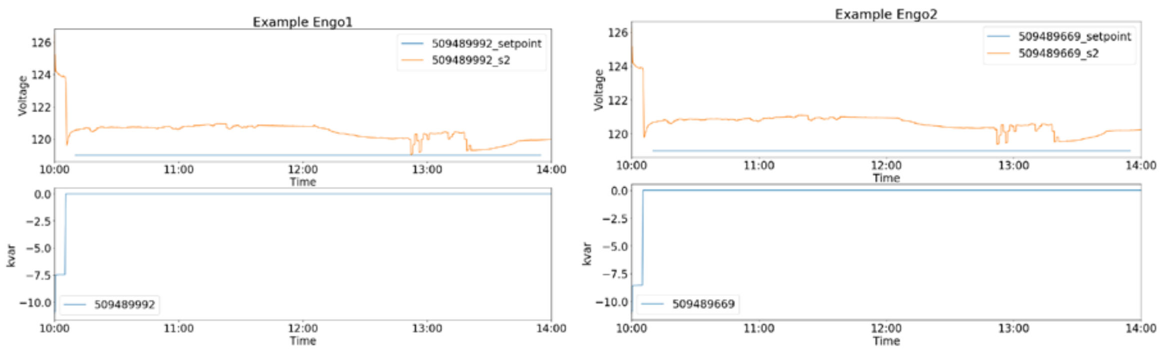


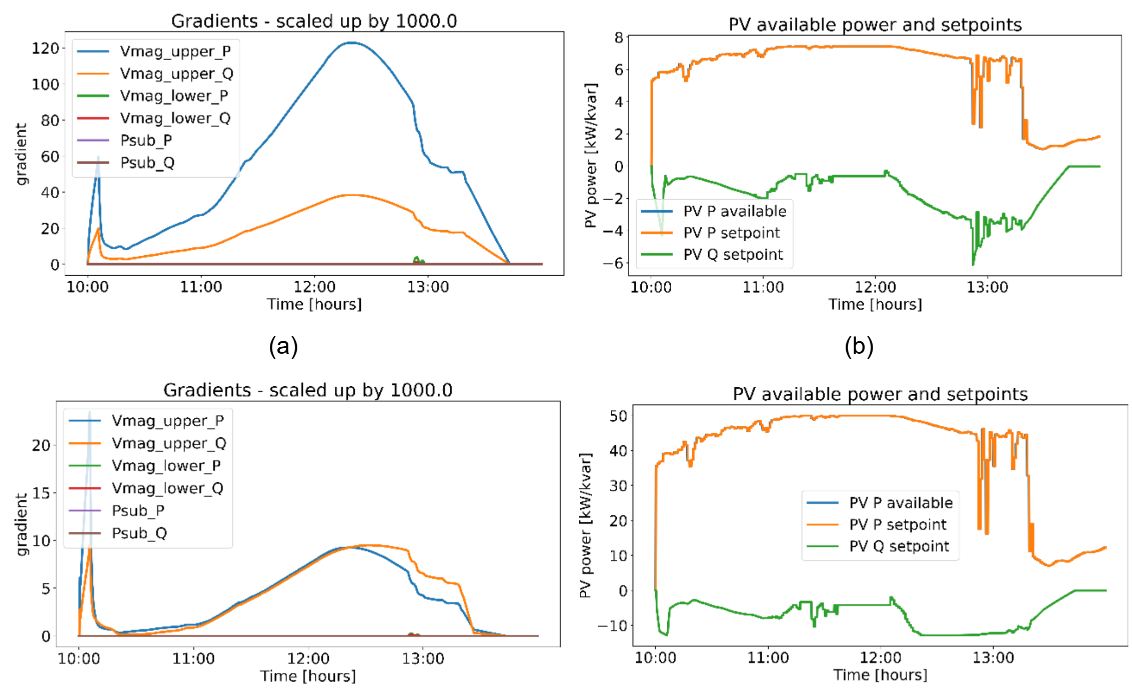
Figure 23. HIL test results of all capacitor banks: (blue) ADMS command and (orange) measured status



(a) (b)

Figure 24. HIL test results of example ENGOs: (a) ENGO1 voltage setpoint from ADMS, measured voltage, and reactive power output; and (b) ENGO 2 voltage setpoint from ADMS, measured voltage, and reactive power output

Figure 25 shows the HIL test results of two example PV local controllers, including the received gradients from RTOPF (6 variables), available power from solar irradiance, active and reactive power setpoints. The results of gradients show that the RTOPF algorithm converge, and local PV inverter controllers respond collectively to high voltages to have small amount of PV curtailment and absorb reactive power. So, the results in Figure 25 show the RTOPF and distributed PV inverters work together with ADMS to regulate system voltages.



(a) (b)

(c) (d)

Figure 25. HIL test results of example PV local controllers: (a) PV4 received gradients from RTOPF master controller; (b) PV4 available power from solar irradiance, active and reactive power setpoints; (c) PV16 received gradients from RTOPF master controller; (d) PV16 available power from solar irradiance, active and reactive power setpoints

Figure 26 shows the real-time measurments of three hardware ENGOs in GEMS, which includes ENGO's voltage setpoint from ADMS, measured voltage and output reactive power. The results show that each ENGO injects reactive power only when the voltage setpoint is higher than its measured voltage. This is as expected since ENGO is capacitor based device and only injects reactive power. These results show the hardware ENGOs work as expected to follow the setpoints from ADMS.

(a) (b) (c)

Figure 26. HIL test results of three hardware ENGOs: (a) ENGO1 voltage setpoint from ADMS, measured voltage, and output reactive power; (b) ENGO2 voltage setpoint from ADMS, measured voltage, and output reactive power; and (c) ENGO3 voltage setpoint from ADMS, measured voltage, and output reactive power

Overall, the results shown in this section demonstrate the performance of voltage regulation of DEHC using ADMS-centered operation via the integrated HIL platform, in particular the following aspects are validated:

- Capability of ADMS to control legacy and grid-edge devices and PV inverters (indirectly and coordinatively)
- Capability of ADMS and distributed control to fast regulate PV inverter setpoints
- Capability of ADMS and grid-edge server to control hardware grid-edge devices.

2.8 Task 8: Deploy ADMS Technologies, Grid-Edge Devices, and Other Hardware in the Field

Substation 1 has all devices installed in preparation for IVVO except for the AMI (Advanced Metering Infrastructure) Bellwether meters. ADMS is autonomously running 24/7 VVO for the feeders associated with Substation 1. The Bellwether meters were installed in November of 2019 but will have a limited scope and only be installed on residential customers. Upgraded Load Tap Changer (LTC) control was installed at the substation transformer. SEL 2411 allows the ADMS to issue a set point which the LTC will regulate the secondary voltage to. 18 primary capacitor banks have been installed. 144 ENGO devices have been installed. WiMAX network installation is completed and functional. WiSUN mesh network allowed for communication with the ENGO devices.

The goal of the field testing in Budget Period 3 is to show the benefits of the coordinated operation of the centralized control layer and the distributed control layers when performing Conservation Voltage Reduction (CVR) targets. Traditional CVR using medium voltage Volt Var equipment cannot always address non-clustered low voltage outliers nor fix service transformer drops and technical losses and can be limited due to consumers with ANSI service voltage violation. The field testing utilized Xcel Energy production-ADMS environment and at the Substation 1 transformer bank #2 which supplies 4 feeders and have 144 ENGO devices installed. ADMS VVO is currently running on this bank in closed loop mode with the CVR objective.

The testing will consist of two parts: manual testing and automatic testing. Manual testing is checking that the ADMS commands to the field devices are successfully received.

Based on the data collected during the automatic testing process, benefits of the centralized control, using ADMS, and coordinated with the local control, using ENGOs, will be quantified. Automatic testing process consists of multiple testing cycles. One testing cycle considers 5 days of testing. Each day of testing consists of monitoring the network state with different combination of the centralized and decentralized control, as it is stated in the table below.

Table 6. One Testing Cycle of the Automatic Testing Process

One Testing Cycle	VVO CL Status	ENGO Status	ENGO Set Point
Day 1	Off	Disabled	Not applicable
Day 2	Off	Enabled	ENGO on with default set point
Day 3	On	Disabled	Not applicable
Day 4	On	Enabled	ENGO on with default set point
Day 5	On	Enabled	ENGO on with dispatched set point

Day 1 and Day 2 testing consist of monitoring the network state without running VVO CL and with ENGOs disabled (Day 1 – ENGO OFF) and ENGOs enabled (Day 2 – ENGO ON). As ENGO devices are deployed at the low voltage outliers, the purpose of the ENGO ON/OFF test (Day 1 / Day 2) is to determine the voltage improvement due to ENGO devices by comparing the voltage measurements of Day 2 (with VAr injection) with the Day 1 voltage measurements (no VAr injection).

Day 3, 4 and 5 consider monitoring the network state while running VVO CL with the different combination of ENGOs configuration: ENGOs disabled (Day 3 – ENGO OFF) and ENGOs enabled with the default setpoint (Day 4 – ENGO ON with default setpoint) and with the setpoint dynamically aligned with the LTC setpoint determined by VVO (Day 5 – ENGO ON with dispatched setpoint). The purpose of the test is to determine the incremental CVR benefits performed by VVO CL with and without the ENGO devices.

The automatic testing process will be performed in April through June 2019. Testing will be performed in multiple cycles, defined in a following way:

- Day 1 & 2 – repeated day by day for 2 weeks (without weekends)
- Day 3 & 4– repeated day by day for 2 weeks (without weekends)
- Day 3 & 5 – repeated day by day for 2 weeks (without weekends)

A detailed field test plan was submitted to the DOE.

2.9 Task 9: Disseminate Results and Transfer Technology

The project team co-hosted a webinar with the ADMS Testbed Industry Advisory Board (IAB) on a quarterly basis. The project team also hosted a workshop that covered the project achievements in BP1 and BP2. The workshop was held in November 2019 and coincided with presentation from several other ADMS-related projects. The webinars, IAB meetings and the workshop was well-attended with participation from organizations including DOE program managers, utility partners, industry partners and academia and other national laboratories. The list of publications from the project is presented in Section 5.

2.10 Task 10: Demonstrate DEHC Architecture in the Field

The Xcel Energy team completed the field testing for Days 3, 4, and 5. Day 1 represents baseline without any controls and Day 2 represents baseline with ENGO enabled with fixed voltage setpoint. For Day 1 the project team used field data before the ADMS went live (GEMS+ENGO pilot project at Englewood Bank#2 hold in 2017). Day 2 field data was synthesized with ENGO data from Varentec.

Table 7. Field-Test Plan Summary Table

One testing cycle	Test Description	VVO CL status	ENGOs status	ENGOs setpoint
Day 1	VVO CL OFF with ENGO OFF	OFF	Disabled	ENGO OFF
Day 2	VVO CL OFF with ENGO FSP	OFF	Enabled	ENGO ON with Fixed SP
Day 3	VVO CL ON with ENGO OFF	ON	Disabled	ENGO OFF
Day 4	VVO CL ON with ENGO FSP	ON	Enabled	ENGO ON with Fixed SP
Day 5	VVO CL ON with ENGO DSP	ON	Enabled	ENGO ON with dispatched setpoint

Table 7 summarizes the field-testing cycle and the ADMS are configured as follows:

- Objective function: Power consumption reduction
- Constraint: Power Factor 0.98 ind – 0.99 cap
- High Constraint:
    - Primary Voltage: Medium Voltage Cap Banks 118 V -126V
    - Secondary Voltage: Low voltage reading (ENGOs) of 116V
    - Secondary Voltage: AMI voltage reading (AMIs of 114V

The field measurements of day 3, 4 and 5 are shown in Figure 27.

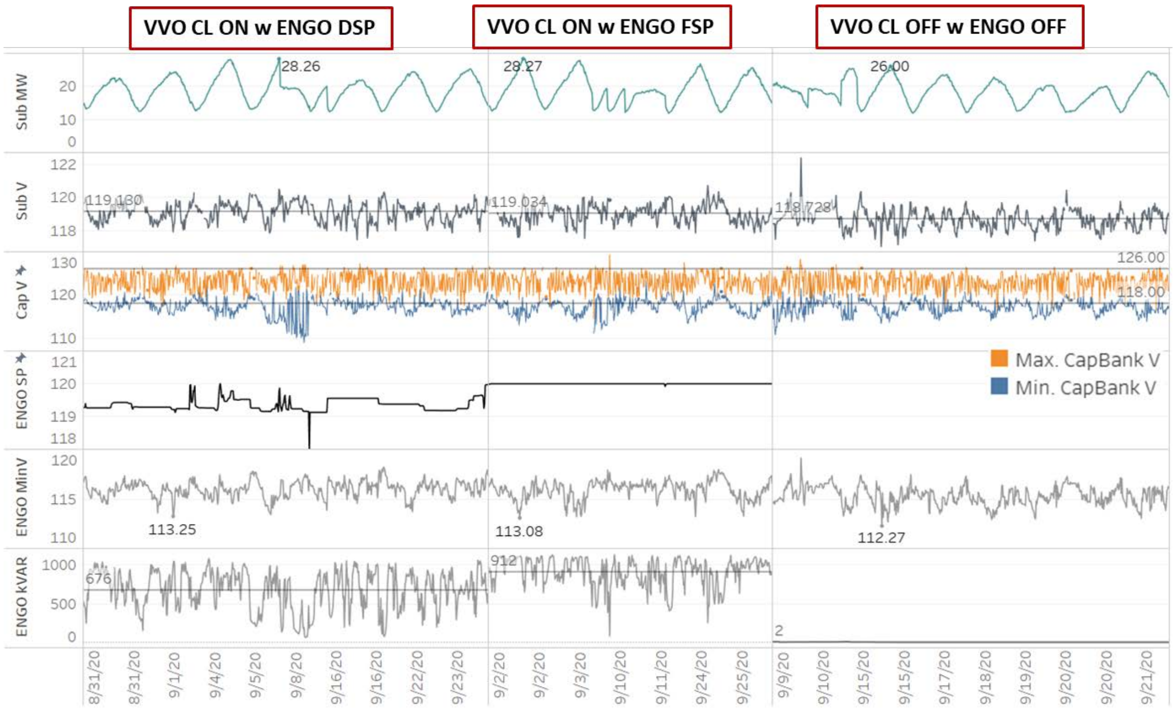


Figure 27. Field measurements (sub MW, substation voltage, ENGO setpoint, ENGO minimum voltage, and ENGO kVAR injection) for Day 5, Day 4, and Day 3

As shown in Table 8, by comparing the minimum ENGO voltage between Day 5 and Day 3 and between Day 4 and Day 3, we observe that the "ENGO ON with dispatched setpoint" days provide 0.98V extra voltage margin while the "ENGO with fixed setpoint" days provide 0.81V extra voltage margin.

Table 8. Field Results Summary for Days 3, 4, and 5

	VVO CL On with ENGO DSP (Day 5)	VVO CL On with ENGO FSP (Day 4)	VVO CL On with ENGO Off (Day 3)
Substation peak load (MW)	28.26	28.27	26.00
Average substation voltage (V)	119.1	119.03	118.73
ENGO min voltage (V)	113.25	113.08	112.27
CAP min V @ ENGO min voltage (V)	115.2	114.5	114.41
Aggregated ENGO VAR injection (kVAR)	676	912	0
Extra voltage margin provided by ENGOs	**0.98 V**	**0.81 V**	**N/A**

When ENGOs are disabled, it represents Day 1 "VVO CL OFF with ENGO OFF". When ENGOs are enabled, it represents Day 2 "VVO CL OFF with ENGO FSP". The substation LTC voltage is controlled with a fixed voltage setpoint of 124V+/-1.5V. As shown in Table 9, by comparing the minimum ENGO voltage between Days 1 and 2, we observe that the ENGOs provide 2.05V extra voltage margin.

Table 9. Field Results Summary for Days 1 and 2

	VVO CL Off with ENGO OFF (Day 1)	VVO CL Off with ENGO FSP (Day 2)
Peak MW	24.87	25.20
Avg substation voltage	124.0	124.0
ENGO min V	116.80	118.85
Extra voltage margin provided by ENGO	**0**	**2.05 V**

By combining the deployment of ENGO devices and a VVO closed-loop control with an ENGO dispatched setpoint, we observe an extra voltage margin in the range of 0.81V and 0.88V that was limited by the voltage measurement errors of the capacitor bank controllers. The aggregated VAr contribution was in the range of 676 and 912kVAr for a VAr capacity of 1,240 kVAr (VAr utilization between 54% and 73%). When adding the secondary voltage constraints as part of the VVO engine, an additional voltage improvement can be achieved. Through this field demonstration, the achieved voltage reduction was 123.7V (Day 1) to 119.2V-119.5V (Days 3, 4 and 5) as shown in Figure 28.

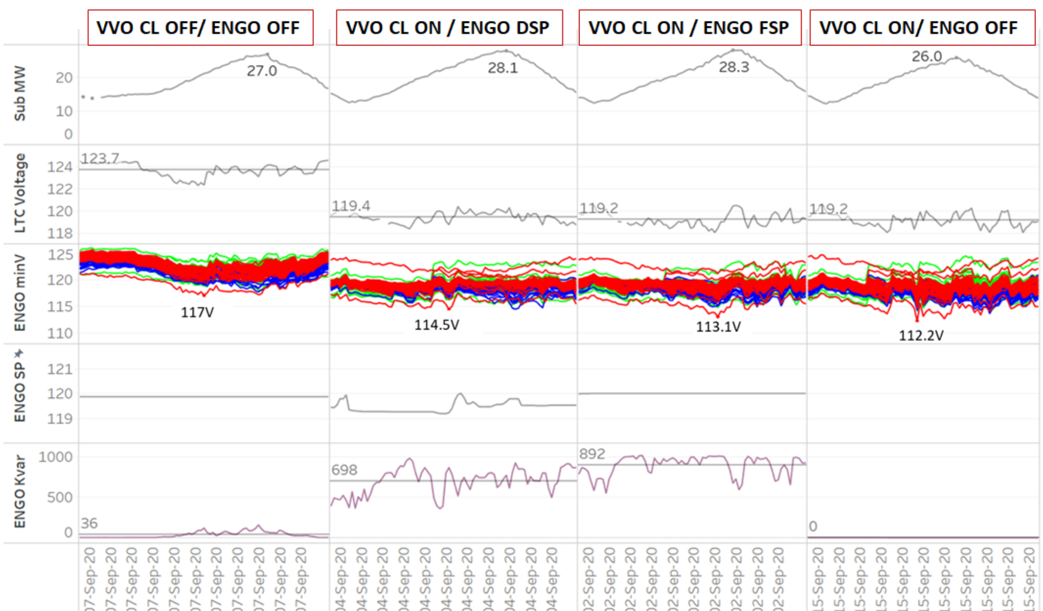


Figure 28. Single-day time-series comparison

2.10.1 Demonstrating PV Control through HIL

The team has successfully completed demonstration of PV control in the lab using HIL experiments. Overall, the successful tests show the efficacy of the DEHC architecture with the coordinated control of ADMS dispatching the legacy devices and grid-edge ENGOs for slow dynamics, while the RT-OPF dispatches the distributed PVs for fast dynamics. Since CVR is configured as the control objective of VVO, TAP position is usually kept low and constant. The high voltage issues we have seen from BP2 (objective is customer voltage improvement) do not exist anymore.

The data from the field has been used to adjust settings and configuration of ADMS in the field and to replicate the field in the ADMS lab. The HIL experiment will demonstrate the value of PV control in future high PV penetration cases.

2.10.1.1 Baseline Scenario

A representative solar irradiance profile with high fluctuations is selected for HIL evaluation of the DEHC architecture. Figure 29 shows the per unit solar irradiance of the selected day with the target 8-hour (8:00-16:00) highlighted. This testing scenario shows the ramping of PV generation until reaching the maximum production then fluctuates up and down for the rest of the test. This testing scenario will test the response of the coordinated control system (ADMS and RT-OPF) with fast changing voltage dynamics caused by the fluctuated PV generation. Note that the solar irradiance profile updates every 15 seconds.

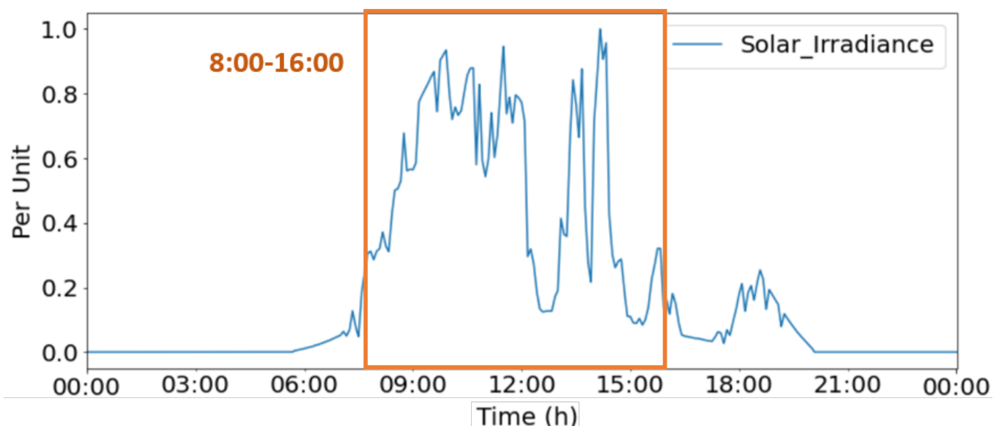
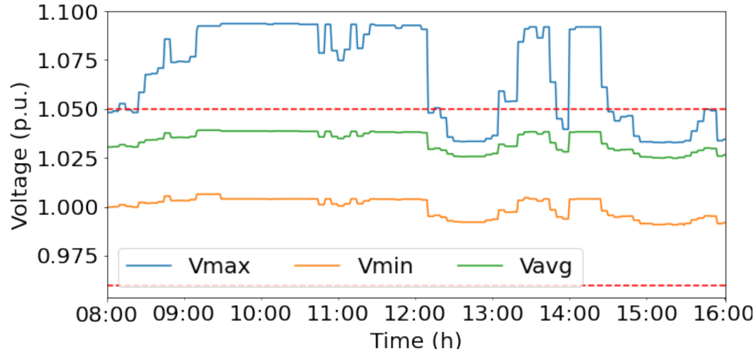
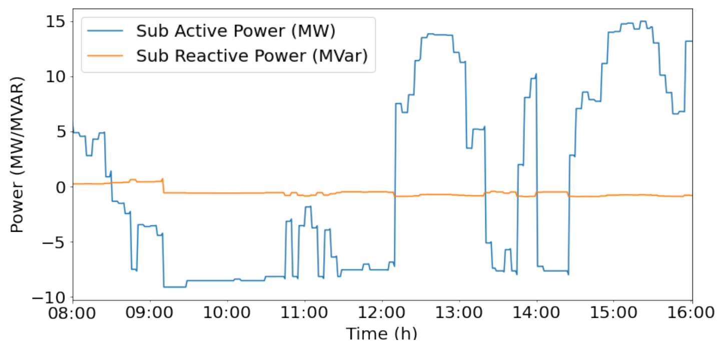


Figure 29. One-day PV solar irradiance profile selected for the HIL testing with target 8-hour run, 8:00–16:00

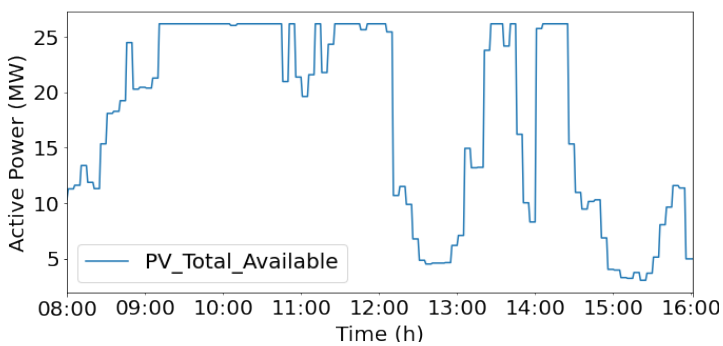
Before demonstrating test results of the DEHC architecture via HIL evaluation, a baseline simulation is performed in OpenDSS. In this baseline scenario the ADMS is disabled, the legacy devices (LTC and capacitor banks) operate in autonomous mode, grid-edge ENGOs are disabled, and all the PVs operate in Unit Power Factor mode. The key results are shown in Figure 30 (a-d). Figure 30(a) shows the maximum, minimum, and average of system voltages, which indicates extremely high voltage violations under this high PV scenario. As seen from Figure 30(b), the active power of substation exhibits high fluctuation, which is caused by the fluctuating PV injections. The reactive power is relatively flat and with less dynamics. The active power is negative for multiple time slots, which means there is active power exported to the substation. Figure 30(c) shows the total PV injection, which has a peak of 25.2 MW and follows the dynamics of the solar irradiance profile highlighted in Figure 29. The total load measurements are shown in Figure 30(d), which indicates very flat dynamics in reactive power and small step changes in active power. This is because the load profiles are updated every 1 hour in OpenDSS. Overall, we can observe that the load demand is lower than the PV production at peak time of solar irradiance.



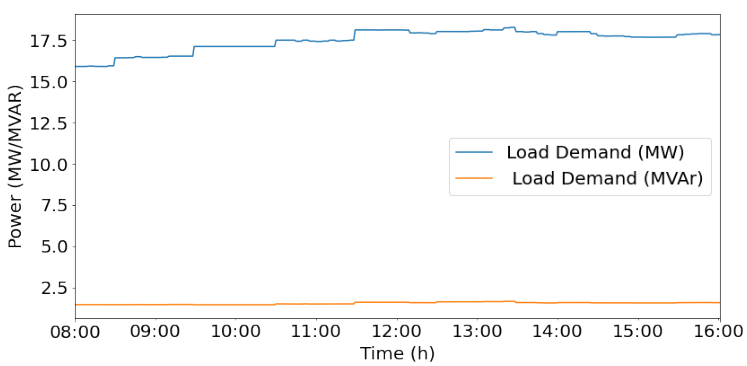
(a)



(b)



(c)



(d)

Figure 30. Simulation results of the baseline scenario: (a) maximum, minimal, and average of system voltages; (b) substation power measurements; (c) total active power injection from all PVs; and (d) total load demand

Figure 31 shows the measurements of the legacy devices including one LTC and 13 capacitor banks operating in autonomous mode. The LTC TAP position is "0" during the whole 8-hour run. For the capacitor banks, Cap 1 is closed around 9:00 and Cap 4 is closed during the whole test, and all the rest of the capacitor banks are open. The results show that the autonomous mode is not good enough for the legacy devices to regulate system voltages within the limits. There is a need to have ADMS dispatch them to achieve system voltage regulation targets.

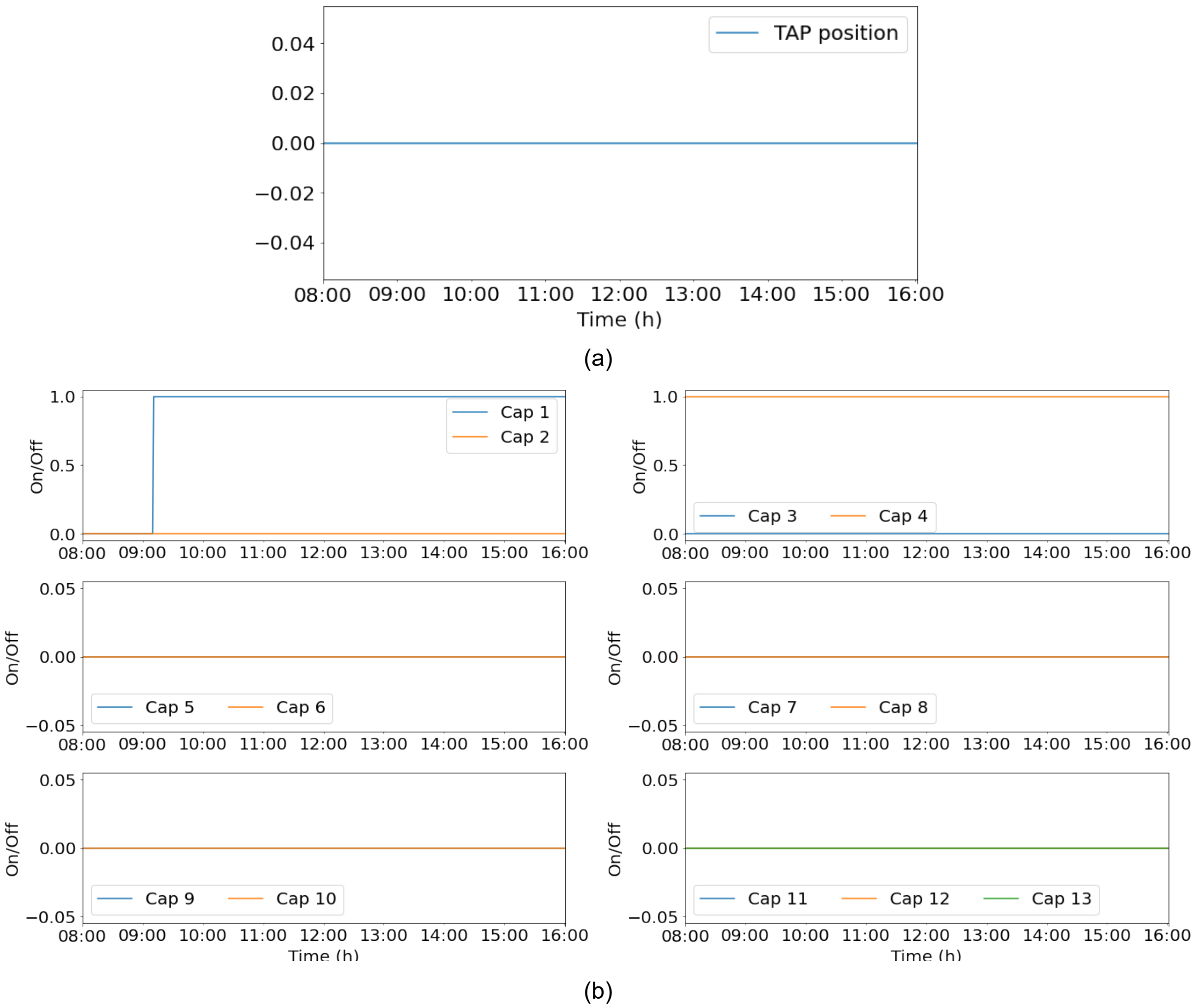


Figure 31. Measurements of the legacy devices of the baseline scenario: (a) TAP position and (b) status of all the capacitor banks

2.10.1.2 PHIL Test with ADMS, GEMS, and RTOPF in the Loop

The configurations of the ADMS and RT-OPF are listed in Table 10 and the test results are shown in Figure 32–Figure 35.

Table 10. Configurations in ADMS and RTOPF

Objective functions:
Power consumption reduction (CVR)
High constraints:
Medium voltage: 116 V (0.967 p.u.) < V < 126 (1.05 p.u.) Deadband = 0.6 V
Low-voltage readings:
114 V (0.95 p.u.) < V < 126 (1.05 p.u.) Deadband = 0.6 V
Power factor constraints:
First limit 0.9 lag, second limit 0.99 lead
With RTOPF:
V_{lower}: 0.96 p.u., V_{upper}: 1.04 p.u.

Figure 32 (a) shows the voltages of all the PVs, which indicates that the voltages of PVs are within the target limits, between 0.96 p.u. and 1.04 p.u. These results confirm the voltage regulation target is achieved with the coordinated control between ADMS and RT-OPF. The voltage profiles in this test are similar to the ones in the previous test.

Figure 32 (b) shows the active and reactive power measurements at the substation. The output active power at the substation is similar to one in the previous test and the reactive power is further regulated to be closer to zero most of the time. The difference is due to the tight second limit of the PF, 0.99 lead, which allows less reactive power export to the grid. Similar to the first test, the PF is maintained within the limits most of the time, except at the beginning of the test and a time slot around 11:00. Therefore, the PF is maintained as expected for this test.

Figure 32 (c) and (d) show the output active and reactive power of all the PVs, respectively. The output active power is the same as the available active power and there is no curtailment. For the output of reactive power, PVs are requested to inject reactive power to the grid for the three time slots that the solar irradiance is very low.

The total reactive power injection of all the ENGOs is presented in Figure 32 (e), which shows that ENGOs have more reactive power injection than the previous test during the time slots with low solar irradiance. This is because more capacitor banks are open to keep a reasonable PF at the substation and ENGOs are dispatched to compensate the reactive power deficiency.

The results shown in Figure 32 further demonstrate the coordinated control between ADMS (legacy devices and ENGOs) and RT-OPF (distributed PVs) for voltage regulation.

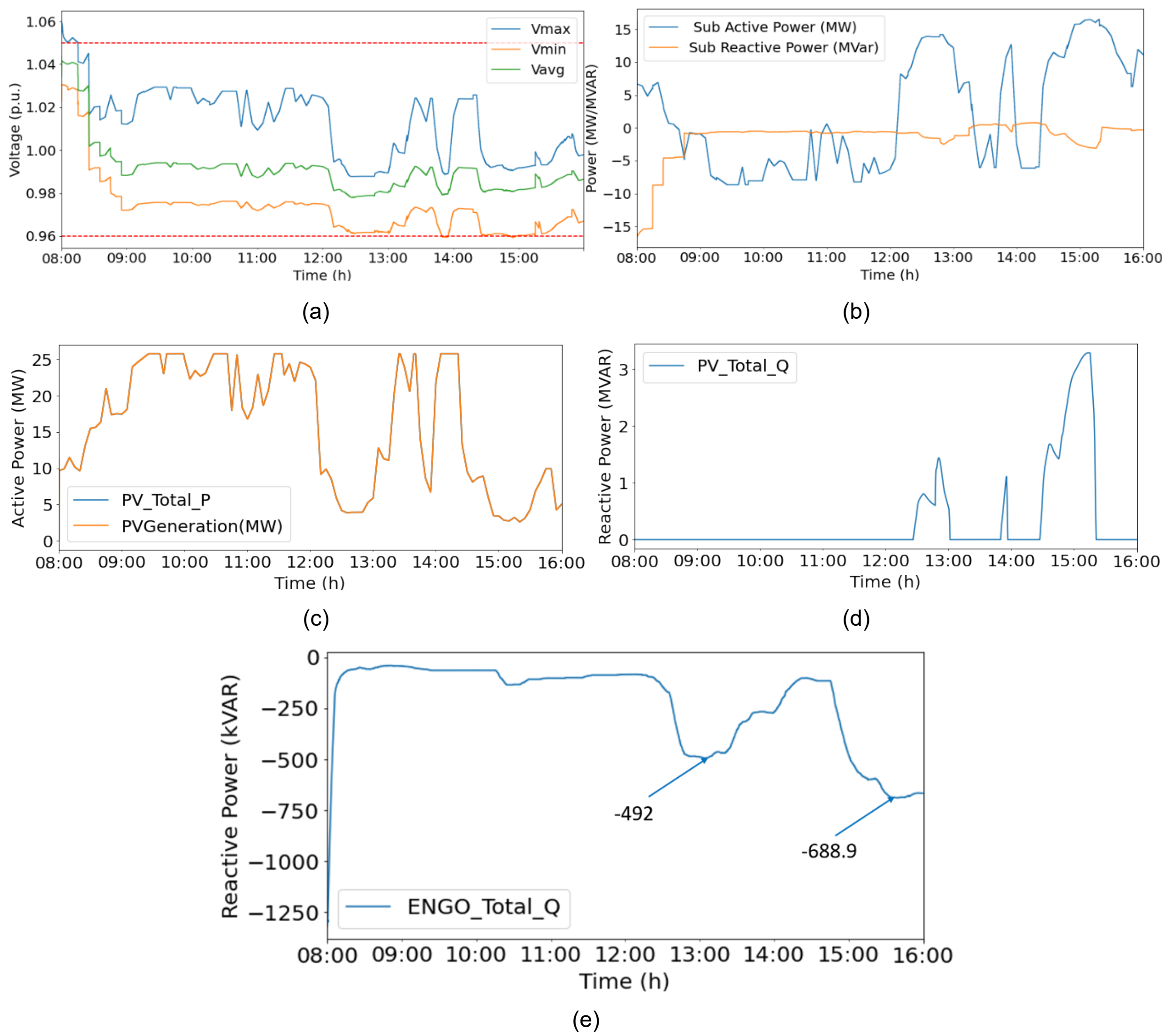
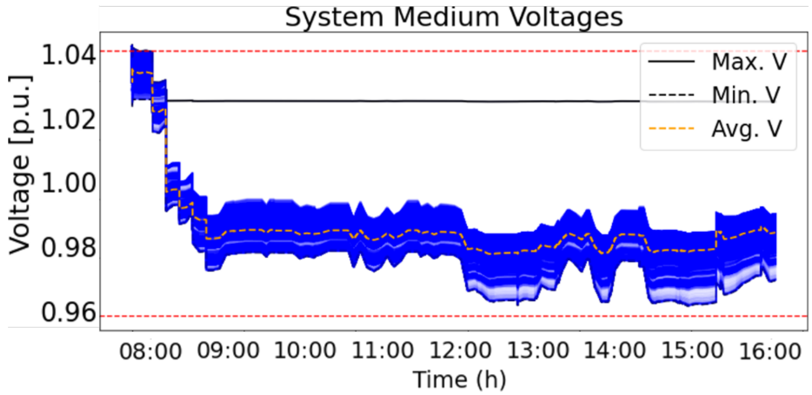
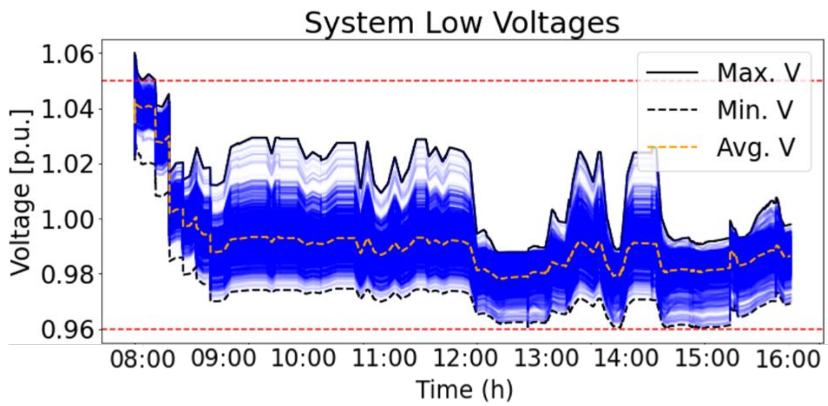


Figure 32. Test results of the first HIL simulation: (a) maximum, minimal, and average of system voltages; (b) substation power measurements; (c) total PV generation; (d) total power injection from all PVs; and (e) total reactive power contribution of all ENGOs

Figure 33 shows the system medium voltages and the system low voltages. In the VVO configurations, the lower limit of medium voltage is 0.96 p.u. The results shown in Figure 33(a) indicate that this target is met because all medium voltages are well above 0.96 p.u.; and the higher limit of medium voltage is 1.05 p.u., so this target is also met. Figure 33 (b) shows the system low voltages, including all the nodes with PVs and other nodes without PVs. Figure 32 (a) shows the voltages of all PVs. The nodes with PVs are the controllable nodes, and they are all controlled within the target limits. For the ones that are not controlled, the voltages are above the lower limit, 0.96 p.u. Note that, this test shows superior voltage regulation than the previous one because all the system voltages are within the target limits in this test. Overall, Figure 33 shows the whole system voltages are maintained well within the target limits, 0.96-1.05 p.u.



(a)



(b)

Figure 33. Measurements of the system voltages: (a) all medium voltages and (b) all low voltages

Figure 34 shows the results of the legacy devices. Figure 34 (a) shows the LTC TAP position and Figure 34(b) shows the LTC voltage reference issued by ADMS VVO. The LTC is dispatched to have very low TAP position (-7) to maintain a low system voltage for CVR, which is one step higher than the previous test, -8. In the 8-hour run, LTC only has five operations, which is still less frequent and should reduce the cost of wear and tear of the LTC. Figure 34 (c) shows the status of all 13 capacitor banks. Obviously, more capacitor banks are opened than in the previous test. During this test, most of the capacitor banks (Cap #1, 2, 4, 5, 6, 7, 9, 10, 11, 12 and 13) opened in the beginning of the test, only Cap #3 closed all the time and Cap #7 opened around 13:00. This explains why the exported reactive power at the substation is kept almost zero during the whole test.

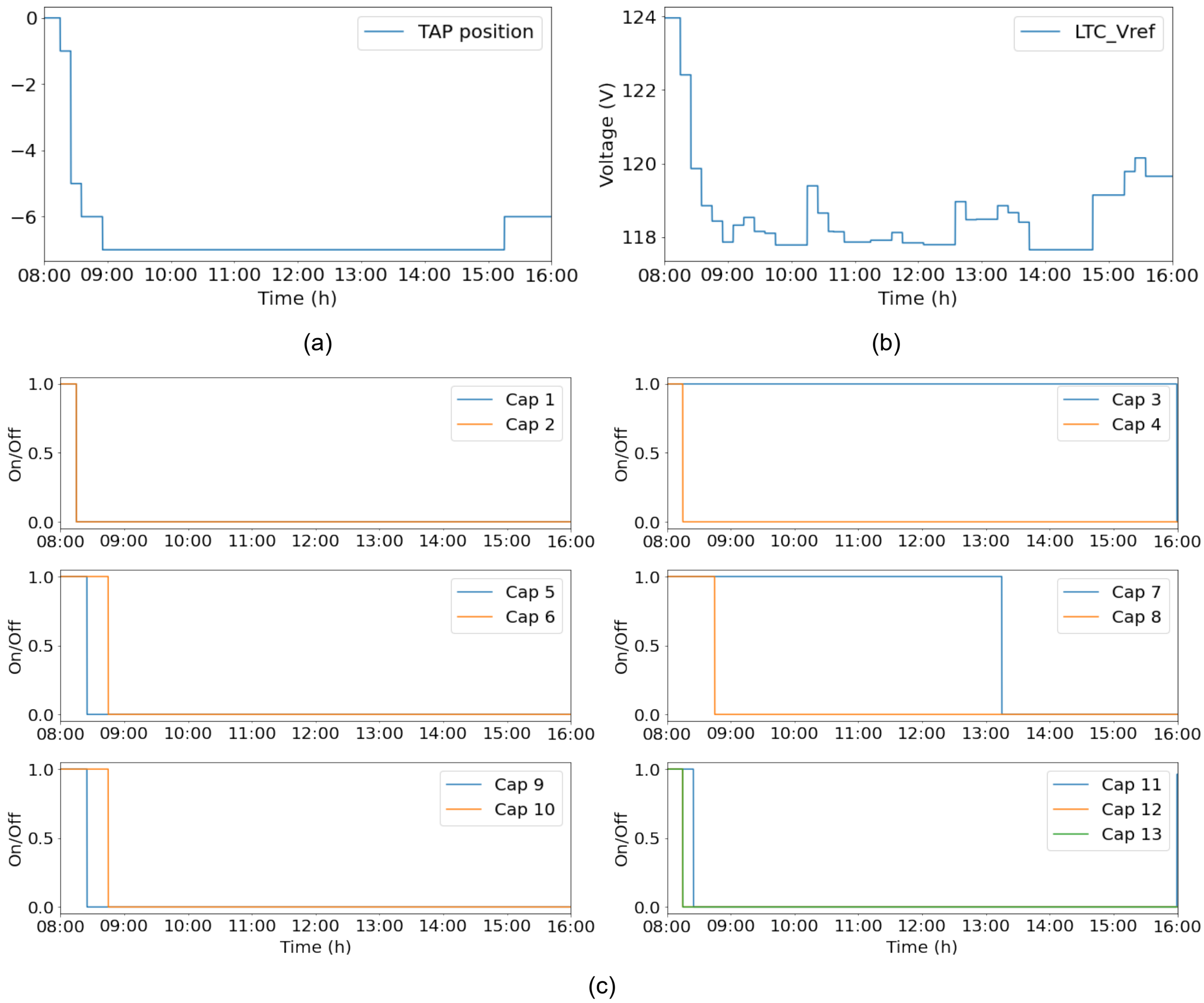
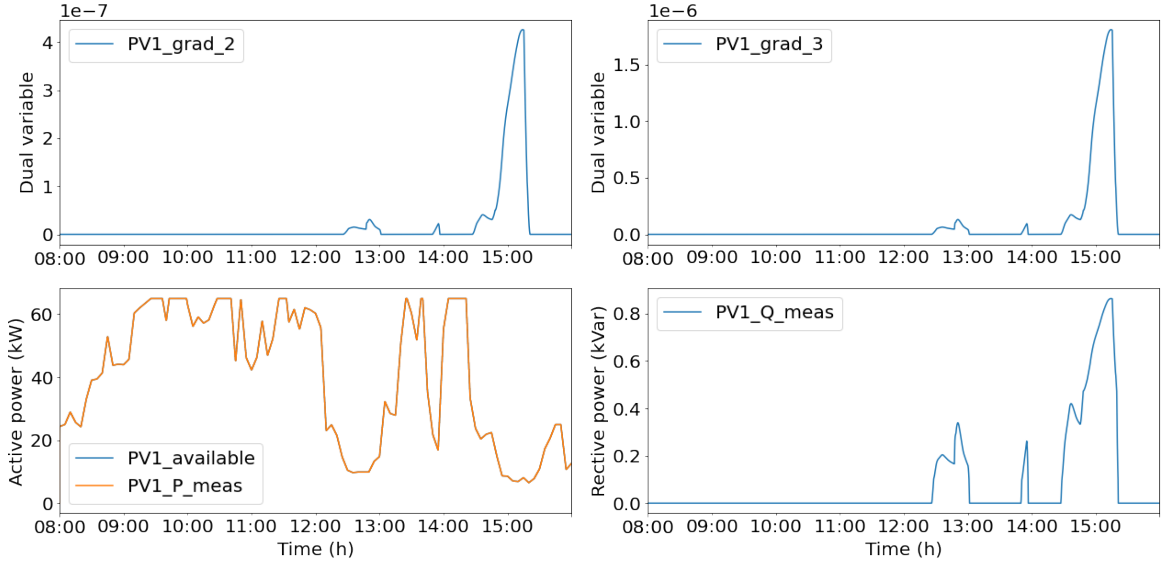
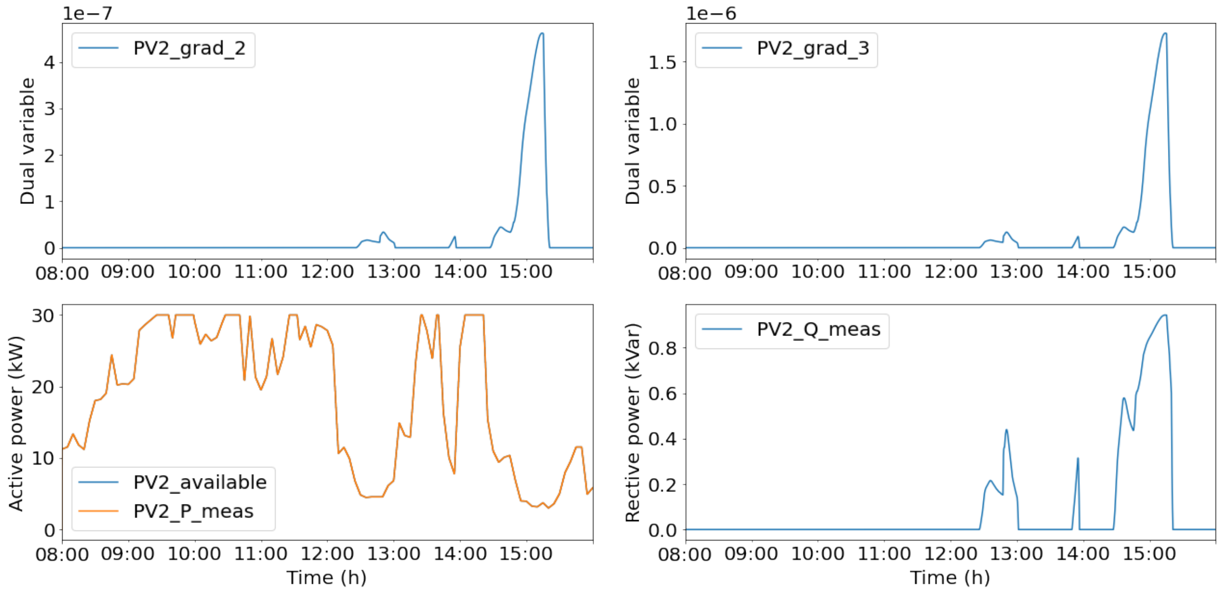


Figure 34. Measurements of the legacy devices of the first HIL simulation: (a) TAP position, (b) voltage reference of the LTC, and (c) status of all the capacitor banks

The same PVs are also selected to showcase the performance of RT-OPF in this test. The results are presented in Figure 35. Both PVs have similar responses. Most of the time, the reactive power outputs of two PVs are zero, as are the dual variables related with under voltage regulation. These two variables are non-zero and very small for multiple time slots when there is very low solar irradiance. Therefore, there is a small amount of reactive power injection during these times and no active power curtailment. The responses of these two selected PVs are similar to the responses of the total PVs. Note that the dual variables of this run are bigger than the ones in previous test and more reactive power is generated to improve the system voltages.



(a)



(b)

Figure 35. Two selected PV outputs: (a) and (b) dual variable related with undervoltage violations, active power, and reactive power

Overall, these two successful tests show the efficacy of the DEHC architecture with the coordinated control of ADMS dispatching the legacy devices and grid-edge ENGOs with slow dynamics and RT-OPF dispatching the distributed PVs with fast dynamics. Since CVR is configured as the control objective of VVO, TAP position is usually kept low and constant. The high voltage issues we have seen from BP2 (objective is customer voltage improvement) do not exist anymore. Instead, low voltages might be an issue. With a tight limit on the lead of the power factor, a very small number of capacitor banks will be open. In this scenario, ENGOs and RT-OPF will contribute and play at local level and low voltages. The selected test scenario (minimal load, high and fluctuated solar irradiance) presents a challenging day for grid operations, thereby highlighting the contribution from RT-OPF and ENGOs.

2.11 Task 11: Analyze Value and Benefits on Utility Networks

The following is a summary of all the updates regarding each of the metrics chosen for the techno-economic analysis. The metrics are divided in annual costs and investment costs. The net difference in cost between the two approaches will be calculated using the net present value of all the costs considered for a period of 25 years.

2.11.1 Upgrade Cost

The first metric is to measure the cost differential between traditional upgrades and the DEHC architecture. To estimate the cost of traditional upgrades, our team has been employing a novel tool called Distribution System Cost Upgrades (DISCO). This tool runs a power flow simulation and detects any excursions from acceptable parameters. Such excursions include voltage violations and other deviations from normal operations that may negatively impact the distribution system. DISCO automatically selects low-cost mitigation measures first and iteratively runs power flow simulations, each time selecting more costly mitigation measures until such point when there are no violations of any type present in the system operation.

2.11.2 Upgrade Cost Results

Baseline – Line upgrades comprise the bulk of the upgrade costs for the baseline scenario. As can be seen in the upgrade costs for S1 and S2, traditional upgrades comprise a much smaller percentage of total investment costs than in the baseline scenario. This is because local control (in the case of S1) and ADMS control (in S2) curtail PV to prevent operations outside limits.

Table 11. Upgrade Costs for the Baseline Scenario

Upgrade Costs—Baseline	
Transformers	$75,902.90
Lines	$460,123.65
Setting changes	$500.00
Total	**$536,526.55**

DISCO results for the Baseline scenario require a substation transformer upgrade which would be very costly. However, a deeper analysis reveals thermal loading at that transformer occurs during only one day in the synthetic year (the peak generation day), and the overload is also relatively short.

Figure 36 shows the MVA at the substation transformer for each of the ten representative days in our simulation. The transformer is rated at 30 MVA and the only day that goes over that level is the Peak day and for a period of less than two hours.

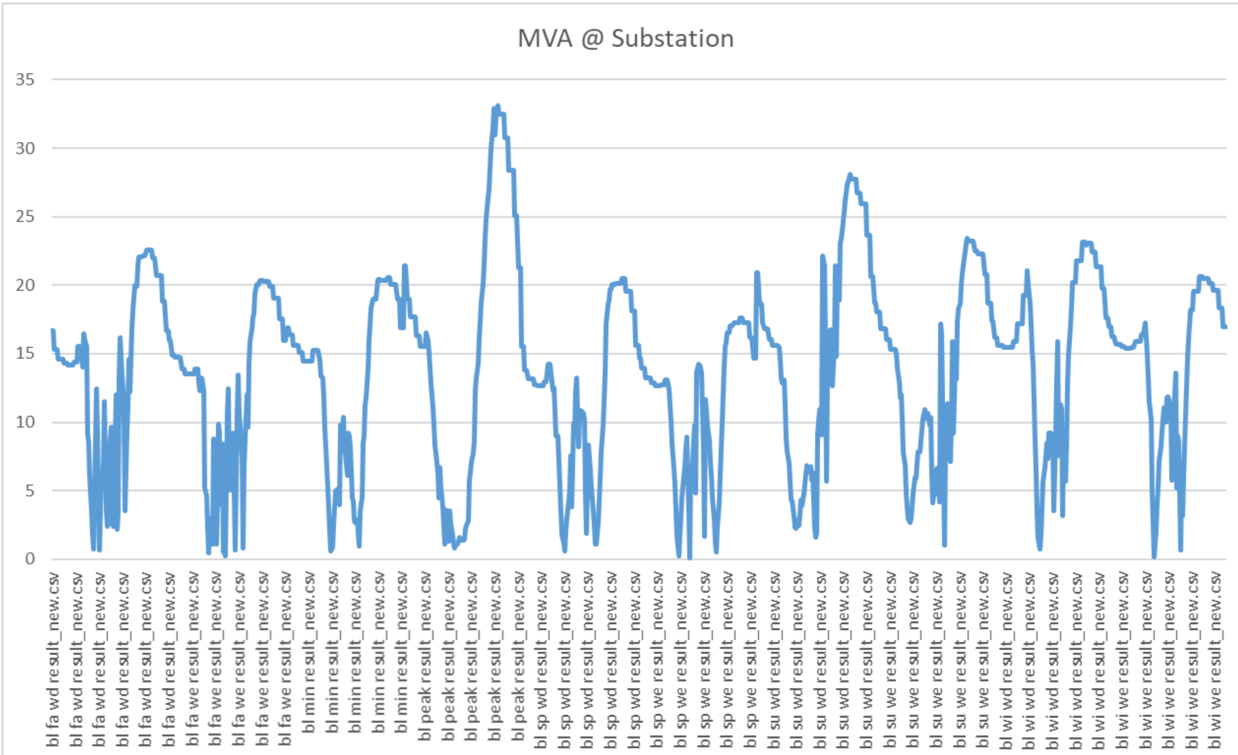


Figure 36. MVA at the substation's transformer for each representative day

Figure 37 shows the number and rating of the equipment identified through DISCO to eliminate voltage and thermal violations in the Baseline scenario.

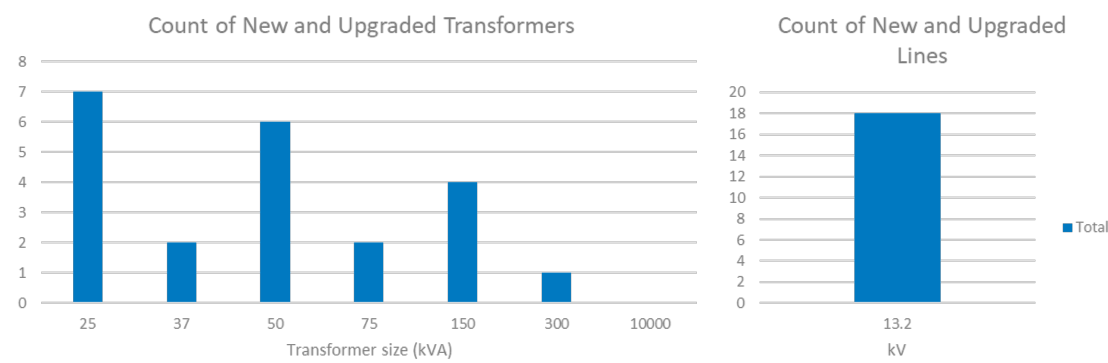


Figure 37. Number and rating of the transformers and lines added to the system to mitigate violations

Figures 38 and 39 show the location of the upgrades in the Englewood feeders.

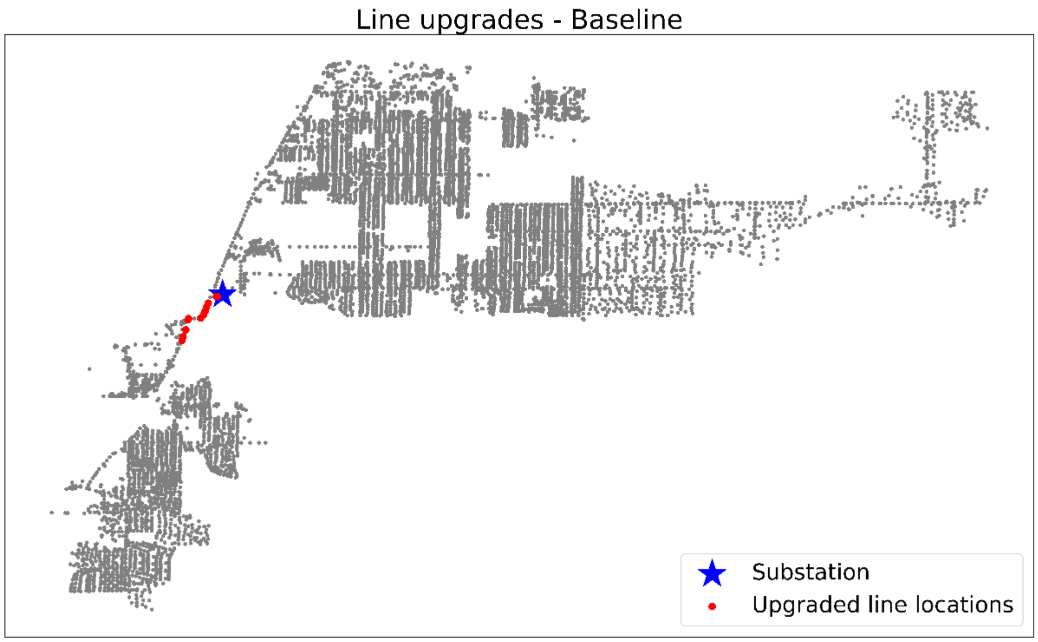


Figure 38. Location of the lines upgraded in the baseline scenario

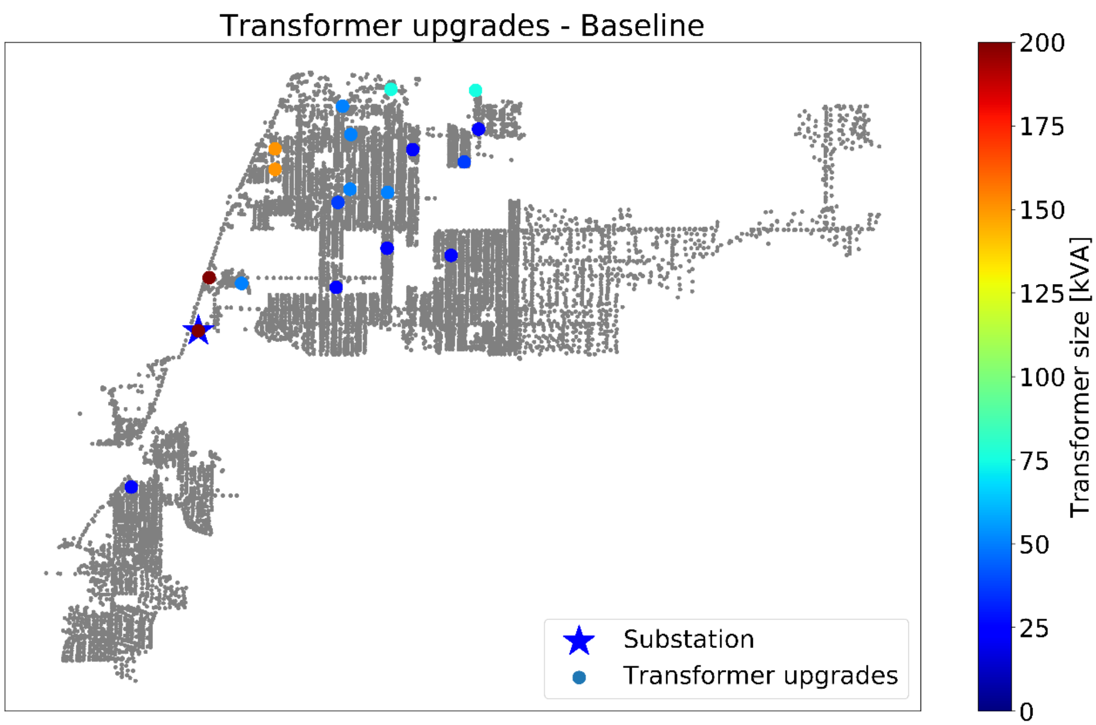


Figure 39. Location of the transformers upgraded in the baseline scenario

Most of the one-time costs for S1 and S2 come from the investment in 144 ENGO devices, which cost $504K in total as shown in tables 12 and 13. Varentec has used the experience gained in this project to optimize the quantity and location of the ENGO devices deployed in the

Englewood feeders and believe that 87 ENGO devices would be enough to provide the same services at the same quality level which would reduce their cost by approximately 40%.

Table 12. Upgrade and ADMS Costs for Scenario 1

Scenario 1 Costs	
Upgrade costs—Scenario 1	
Transformers	$80,659.20
Lines	$0
Setting changes	$0
Total upgrade costs	$80,659.20
Prorated ADMS+GEMS cost	$79,644
144 ENGOs @ $3,5000 each	$504,000
Total	**$664,303.20**

Table 13. Upgrade and ADMS Costs for Scenario 2

Scenario 2 Costs	
Upgrade costs—S2	
Transformers	$39,953.00
Lines	$0
Setting changes	$0
Total upgrade costs	$39,953.00
Prorated ADMS+GEMS cost	$79,644
144 ENGOs @ $3,5000 each	$504,000
Total	**$623,597.00**

2.11.3 S1 and S2 Control Investment Costs

The upgrade costs for the DEHC architecture include the prorated cost of the ADMS and the installed cost of the ENGO devices in addition to the upgrade costs reported above. The cost of the ADMS and GEMS (Varentec's system for controlling ENGO devices) is prorated to account for the fact that the cost of ADMS and other equipment reported to the Colorado Public Utilities Commission applies to the entirety of Xcel Energy's territory in Colorado.[6] Additionally, a utilization factor (UF) of 30% was applied exclusively to ADMS costs to account for the fact that ADMS has uses beyond PV integration.

[6] https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates & Regulations/19AL-XXXXE_Nickell Direct Testimony_FINAL.pdf

The cost stated by Xcel for the ADMS system for the distribution system was $20.3 million.[7] Xcel and NREL selected a 30% UF estimate to reflect the other uses of the ADMS system in Xcel's grid. The ADMS cost after the UF was added to the cost of Varentec's GEMS system. These were costs for the state-wide deployment of both systems. A prorate factor of 0.56% was used to estimate the cost applicable to just the feeders analyzed in the present study. Such factor was determined by dividing the annual energy consumption in the Englewood feeders (as obtained from our OpenDSS simulations) over the total energy consumed in Xcel's territory in 2018. The prorated sum was then added to the cost of the 144 ENGO devices installed in the feeders for a total of $584 thousand as shown on Table 14.

Table 14. Calculation of the Prorated Costs of the ADMS and GEMS Systems and ENGO Devices

ADMS distribution cost	$20.30	Million
ADMS utilization factor	30%	
(1) ADMS cost after utilization factor	$6.09	Million
(2) IVVO cost (GEMS)	$8.20	million
Prorate factor	0.56%	
(3) Prorated (1)+(2)	$79,644	
(4) 144 ENGOs @ $3,500 each	$504,000	
Total (3)+(4)	$583,644	

2.11.4 PV Curtailment

We have successfully run the representative day simulations for the Baseline, S1 and S2 scenarios. We compared the total PV production for commercial and residential systems between those two scenarios to calculate total annual curtailment. There is no curtailment in the Baseline scenario because in that scenario there is no capability to do so. The curtailment in the S1 scenario was very limited: 371 MWh (0.53% of the total annual PV production) for S1 and 57.5 MWh (0.32%).

Using an average rate of $0.0916/kWh for commercial customers and a rate of $0.0916/kWh for residential customers, we found that the total dollar value of PV curtailment is $44.7K per year for the selected feeders in S1 and $26.2 thousand for S1. This is a lost opportunity cost borne by the customers. This dollar value represents annual electricity bill savings lost by the customers who own PV systems.

2.11.5 Power and Energy Drawn at the Substation Level

The power drawn from the substation is equal to the load minus PV generation plus energy losses (see figure 40 below).

[7] https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates & Regulations/19AL-XXXXE_Nickell Direct Testimony_FINAL.pdf

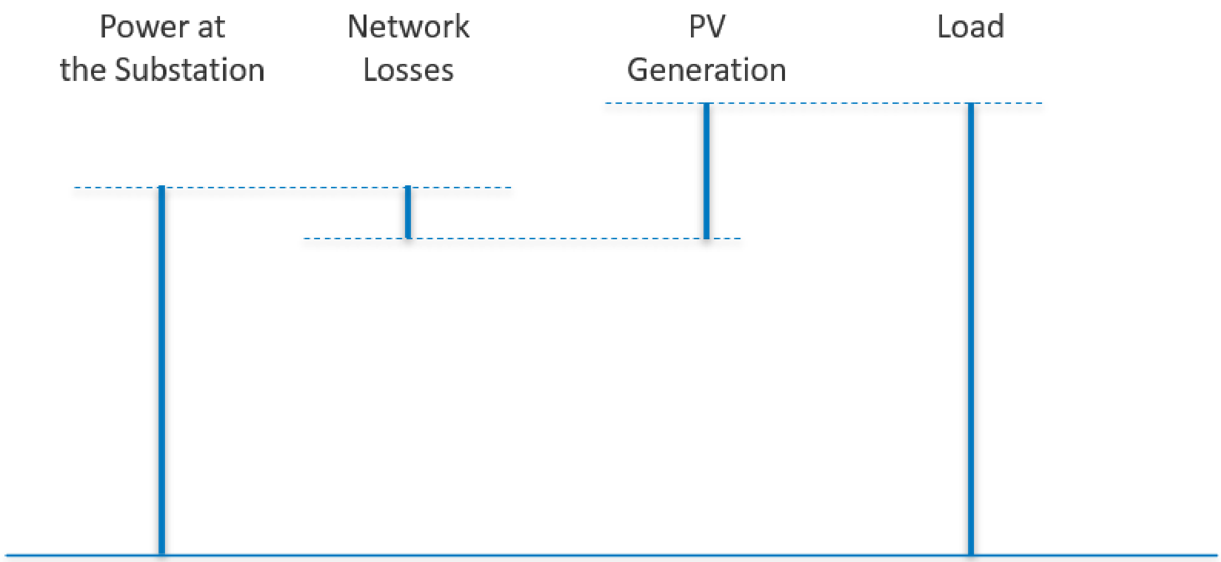


Figure 40. Simplified representation of the factors that contribute to the load experienced at the substation

In the simulation results, S1 shows a decrease of 2 GWh/yr in energy drawn from the substation with an annual value of $138K, while an estimated avoided cost rate is used for Xcel of $66.67/MWh (annual average supplied by Xcel). For S2, the energy decrease was 2.7 GWh/yr, with a dollar value of $177.4 thousand.

Table 15. Annual Energy Changes at the Substation

	Substation Demand and Avoided Capacity	S1 - Baseline	S2 - Baseline
Annual	Load increase (MWh/yr)	(2,834)	(3,642)
	Network losses increase (MWh/yr)	691	759
	Energy substation increase (MWh/yr)	(2,066)	(2,662)
	Energy differencial dollar value ($/yr)	$ 137,761	$ 177,470

Curtailment in both scenarios was less than 1%, as shown in Table 15. Curtailment reduces the ability of utility customers to reduce their energy use and, consequently, their bills. The dollar value of the curtailment in Table 16 represents the savings loss to the utility customers. Xcel Energy in Colorado provides net metering to its customers; therefore, each kWh curtailed is a kWh that the customer needs to consume from the grid at its full rate. In Colorado, net metering credits roll-over month by month.

Table 16. Annual Curtailment in MWh and Dollar Value

Curtailment - Annual Values	S1 - Baseline	S2 - Baseline
Increase in PV generation (MWh)	(76)	(57.53)
Total curtailment %	0.11%	0.32%
Curtailment $ value (negative = cost)	(9,163.00)	(26,226.54)

2.12 Task 12: Disseminate Results and Transfer Technology

The project team hosted two virtual workshops which were held on November 9th and 10th, 2020. The title of the event was *Advanced Distribution Management System Test Bed and Architectures for Grid-Edge Management Workshops*. The event brought over 70 external participants from 45 organizations. This was the most attended ADMS workshop to date. ECO-IDEA presented its latest accomplishments and shared a virtual demonstration of ECO-IDEA's most recent work, which was followed by breakout sessions with industry, utility and research organizations. A summary of the workshop breakout discussions and survey responses were completed and shared with DOE. Project updates were also presented to the IAB on quarterly basis using the webinar format.

3 Significant Accomplishments and Conclusions

3.1 Significant Accomplishments

The following are the significant accomplishments from the project:

- Developed and validated novel hybrid control architecture
- Demonstrated reliable and secure grid operation for high PV grids
- Developed and tested interoperable interfaces for integration of system-level controls on the Utility Enterprise Bus
- Performed laboratory and field validation of the hierarchical controls
- Developed and performed a techno-economic analysis to comprehensively quantify cost-benefits for different scenarios
- Engaged with over 40 industry members through regular Industry Advisory Board (IAB) meetings and industry-wide annual workshops

3.2 Technical Outcomes

The following are the key technical outcomes from the project:

- The simulations demonstrate the effectiveness of DEHC architecture for voltage regulation
- The local volt/var control of PV smart inverters alone cannot resolve the voltage issues, even with ADMS control of legacy devices
- ADMS control of legacy devices coupled with fast regulation of PV smart inverters using RTOPF showed improved voltage regulation
- Coordination with PV inverters is important for system-level services like CVR, voltage regulation

3.3 Conclusion

This project developed and demonstrated data-enhanced hierarchical control (DEHC) architecture that enables integration of high levels of solar generation into the distribution grids and existing utility systems. The DEHC architecture enables a hybrid control approach where a centralized control layer is complemented by distributed control algorithms for PV inverters and autonomous control of grid edge devices. Schneider Electric's advanced distribution management system (ADMS) is used to manage the legacy devices such as load tap changer and capacitor banks to perform Volt-VAR optimization (VVO). The PV smart inverters are dispatched by the distributed control algorithm based on real-time optimal power flow to support the VVO. The grid edge devices support the VVO and offer additional benefits in the form of conservation voltage reduction (CVR). The ADMS synergistically coordinates the operation of legacy assets, grid edge devices, and PV smart inverters. This report includes the case studies on Xcel Energy's distribution system that assess the impacts of high PV penetration levels on the voltage regulation and CVR in the absence of the DEHC and when the DEHC is deployed. The DEHC architecture is evaluated using numerical simulations and hardware-in-the-loop simulations. The results from the field deployment are also documented in this report.

The key findings of this project are:

1. The load tap changer (LTC) has significant influence on the distribution network voltages. By changing the LTC tap position, the ADMS is able to regulate the rising bus voltages in the presence of excessive PV generation. However, the LTC alone is not sufficient to ensure the voltage regulation across the feeder.
2. The reactive power support from the PV smart inverters and grid edge devices further improved the voltage regulation by ensuring that all the bus voltages are within the acceptable limits. The distributed control of the PV smart inverters resulted in minimal active power curtailment (less than 1%).
3. The ADMS and grid edge device field deployment results indicate that when the grid edge devices are in service, they provided an extra voltage margin of up to 2.05 V so that the ADMS VVO can further reduce the bus voltages through CVR. As such, the grid edge devices help obtaining additional energy savings when ADMS is exercising CVR.
4. In the laboratory simulations, the DEHC architecture resulted in CVR savings in the range of 3% to 5% compared to the baseline while ensuring voltage regulation in the presence of high PV penetration.
5. The techno-economic analysis results indicate that there are higher initial investment costs to deploy the ADMS and grid edge devices in the studied distribution system ($623,597) compared to the traditional network upgrades required in the baseline ($536,526). However, there are cost savings in the order of $177,470 per year in the form of energy savings obtained through CVR when the ADMS and grid edge devices are deployed. Additionally, the ADMS and grid edge devices also improve the distribution network voltage profile.

4 List of Publications from the Project

Papers

1. H. Padullaparti, J. Wang, S. Veda, M. Baggu, and A. Golnas, "Evaluation of Data-Enhanced Hierarchical Control for Distribution Feeders with High PV Penetration," accepted to IEEE Access, 2022.
2. J. Wang, H. Padullaparti, S. Veda, I. Mendoza, S. Tiwari, and M. Baggu, "Performance Evaluation of Data-Enhanced Hierarchical Control for Grid Operations," IEEE Power & Energy Society General Meeting (PESGM), Montreal, QC, Canada, 2020, pp. 1-5.
3. F. Ding, H. V. Padullaparti, M. Baggu, S. Veda and S. M. Danial, "Data-Enhanced Hierarchical Control to Improve Distribution Voltage with Extremely High PV Penetration," in IEEE Power & Energy Society General Meeting (PESGM), Atlanta, GA, USA, 2019, pp. 1-5.

Presentations

1. Murali Baggu, Emiliano Dall'Anese, Rohit Moghe, Brian Amundson, Scott Koehler, Kevin Schneider, *Evaluation of Advance Distribution System Applications Using DMS Centric Approaches*, IEEE Power & Energy Society, Transmission & Distribution Conference 2018, Denver, CO, April 19, 2018.
2. Harsha Padullaparti, *ADMS-Centric Operation for High-PV Distribution Grids*, Xcel Energy's Electric Distribution Engineering Conference, Aurora, CO, February 27, 2020.