An Introduction to the Federated Architecture for Secure and Transactive Distributed Energy Management Solutions (FAST-DERMS)

Preprint

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An Introduction to the Federated Architecture for Secure and Transactive Distributed Energy Management Solutions (FAST-DERMS)

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***Abstract*—Deployment and capability of distributed energy resources (DER) in power systems is growing rapidly. These resources present an opportunity for low-cost provision of energy and grid services. The Federal Energy Regulatory Commission recently provided rulings to enable market participation of these distribution-connected resources, but the prevailing strategies for their management may not scale well to meet future needs. This paper introduces the Federated Architecture for Secure and Transactive Distributed Energy Management Solutions (FAST-DERMS) which was designed to address this need. In it we describe the architectural features of the approach, and a reference controls implementation employing a hierarchical coordination that includes stochastic optimization, model predictive control, and a simple real-time management scheme. Sample results from simulation show firm transmission-level service provision measured at the distribution substation.**

***Index Terms*—Grid Architecture, Hierarchical Control, T&D Coordination**

I. Introduction

State, National, and International climate goals will see consistent growth in distributed energy resource (DER) deployment. These resources may be harnessed to provide reliability and balancing services to minimizes reliance on centralized generation. In the US, FERC order 2222 has attempted to open up participation in transmission markets for DER. However, the prevailing operational strategies for managing DER for providing grid services are unlikely to scale as we move to systems with very high DER penetration.

The current paradigm for engagement of distributed resources is through aggregation and centralized management by transmission systems operators (TSOs), in which distribution utilities are left entirely out of the loop, termed a "Total TSO" architecture [1]. At high penetrations of DER, dispatches for TSO objectives may create reliability issues, such as overvoltage, in the distribution systems. TSO management of these types of issues isn't feasible, as computation of systems of that regional size and granularity is intractable with available hardware. Further, the communications for this micro-management between each small resource and/or resource aggregator and the managing TSO may overwhelm its energy communication network.

Instead of vastly increasing the complexity of the TSO, an alternative architecture could ask aggregators to inform Distribution System Operators (DSOs) of their market participation, and give the DSOs an opportunity to constrain those transmission level grid service offers. However, as DSOs identify constrained portions of their system caused by resource participation, the process to recursively determine constrained aggregator bids to transmission markets will become ever more challenging as the number of these bids that require vetting grow. There is a need for solutions that can minimize the impacts of these challenges as we achieve scale.

The capacity and capability of DERs have increased rapidly recently. This growth brings both challenges and opportunities and numerous optimization and control strategies have been developed to manage DERs [2]. Hierarchical and distributed control architectures offer promising solutions given the large number of devices, timescales of market interaction, and various local and system objectives and constraints [3]. However, current DER management and control solutions are often still silo-ed by resource type, are largely centralized, and almost none tackle the potential conflicting objectives between TSO and DSO services [4], which will ultimately limit scalability. DER management literature has attempted to tackle some of the challenges such as coordination between DER types with different dynamics [5], distributed control approaches for real-time operations [6], and explicit uncertainty management [7]. The excellent works are focused on specific conditions and challenges, but few works have tried to bring each innovation together, and design a control system capable of heterogenous DER management for both TSO and DSO solutions at scale, and fewer still designed their control explicitly grounded in grid architecture fundamentals [8]. In the Federated Architecture for Secure and Transactive Distributed Energy Management Solutions (FAST-DERMS) project, we develop a flexible approach that distributes computational complexity, minimizes communications, and simplifies TSO/DSO interactions, while

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enabling the provision of reliable, resilient, and secure transmission and distribution energy and grid services through the scalable aggregation and management of utility-scale and small-scale DERs.

The contributions of this work are as follows: (1) a succinct articulation of an architectural vision and its advantages and disadvantages, based on established Grid Architecture principles; (2) A novel hierarchical control approach to managing the stochasticity in distribution feeder power flow using DER that is a key controller in the described architecture; and (3) Simulation results of the control deployed on a standards-based platform successfully providing firm feeder power flow commitments for wholesale electricity markets using heterogenous DER.

To provide an introduction to the FAST-DERMS approach and control implementation, the paper is organized as follows: Sec. II highlights the architectural considerations that underpin the FAST-DERMS approach, Sec. III describes the reference controls implementation that is being employed in FAST-DERMS simulation and demonstration, Sec. IV provides some sample results from tests of the reference controls on a small system, and Sec. V concludes, including a short discussion of future work.

II. Architectural Design

Grid architecture is an emerging discipline that aims to synthesize and analyze the structure of operational coordination of grid systems and resources to manage complexity. It draws on fields such as Systems Architecture, Network Engineering, Controls Theory, and Graph Theory to design the structure of interaction. Appropriate structure will simplify decisions and futureproof investments while poor structure can lead to complex and costly integration and stranded assets [8]. Desirable characteristics in a grid architecture include appropriate observability, high scalability, minimizes cybersecurity vulnerability, employs layered optimization in which large optimization problems are decomposed into coordinated sub-problems, avoid tier bypassing in which information or controls communications skip an entity that manages a section of the power network that is impacted by control actions, avoid hidden coupling in which signals to manage DER states can come from two or more control centers with different objectives, and minimize latency cascading by limiting the number of cascading systems through which data must flow serially [1].

The varying structures for DER-DSO-TSO interactions can be described as a spectrum of grid management architectures that look to identify how resources connected through the distribution grid provide grid services relevant to transmission markets [1]. On one end of the spectrum is the ”Total TSO” architecture, described in section I. This is characterized by direct participation of DER and their aggregators in transmission-level energy markets without including distribution system operations in the loop. A ”Total TSO” architecture includes tier bypassing of the DSO, employs very limited layered optimization, has limited observability of the network connecting its resources, and may have scaling issues trying to manage many small resources in large systems.

In the middle of the spectrum are the ”Hybrid DSO” architectures. These architectures allow DER and Aggregators to participate directly in transmission-level markets, but must also interface with the DSO to ensure their system constraints are met. They avoid some tier bypassing, but create opportunities for hidden coupling, and may be limited in their scalability as they can greatly increase complexity as more and more DER and aggregators attempt direct participation in TSO markets. These architectures provide some limited recourse for DSO operators, but may require extensive communications and recursive modeling and bid optimization to generate feasible transmission offers at high DER penetrations.

On the far end of the spectrum is the ”Total DSO” architecture. In this DER and their aggregators contract to provide grid services with the DSO. The DSO can then sell those services in transmission markets and share the profits with their participants. These architectures contain most of the desired characteristics of a grid architecture, though they can result in some latency cascading. The advantages that Total DSO architectures bring to the problem of DER management at scale are:

- Computational tractability - Layered decomposition of the problem of managing DER parallelizes computation across transmission and distribution operation centers, avoiding over burdening TSO market solvers with millions of small resources to be optimized.
- Reduction in communications for each end point - communications to/from aggregators and DER are only made to the DSO, rather than having redundant communications to both operators and recursive bid development to ensure reliable electricity distribution.
- More reliable electricity distribution - With no tier bypassing, DSOs are free to manage DER such that service quality within the distribution can be improved while DER benefit from participating in transmission markets.

FAST-DERMS employs the Total DSO architecture to leverage these advantages. It is designed for scalability and affordability of DER coordination in high DER penetration systems (greater than 50% of load met by DER) [9]. Fig. 1 displays the FAST-DERMS architectural approach in which four federated entity classes act with minimal integration to provide control and aggregation functionality in the provision of transmission system level services from distribution sited DER. At the heart of this approach, and the controls described in later sections, is one of these entities, the Flexible Resource Scheduler (FRS). The approach decomposes the DSO management problem into sub-problems at the distribution substation and feeder level, each handled by their own FRS. The FRS aggregates all DER and DER aggregators within the substation to provide transmission-level services that are regulated and measured at the substation connection to the sub-transmission network. By managing the substation power, the approach has two additional advantages over other Total DSO models: (1)

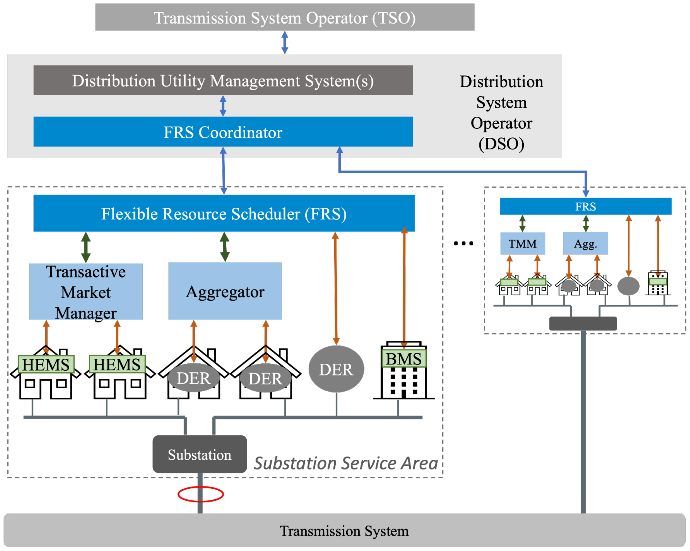

Fig. 1. The FAST-DERMS Architecture Concept

measurement and verification may be cheaper as expensive transmission-grade meters and telemetry will not be required at each DER; (2) The transmission / distribution system interface can be simplified as the TSO no longer need visibilility of the DER, only the points at which their transmission system connect to the distribution system. Another key feature of the federated architecture is that the FRS is designed to simultaneously support aggregator participation, direct DER participation, and transactive DER that prefer to respond to price signals over power dispatches. To manage an entire distribution system, multiple instances of an FRS operate in a distributed fashion to manage separate substations, and are coordinated together in the DSO operations center where the connection to TSO system operators can reside.

More detailed descriptions of the functional components of the FAST-DERMS architecture can be found here [10].

III. Reference Hierarchical Control Framework

The goal of FAST-DERMS is to create a flexible, federated environment for heterogeneous DER to provide grid services that simultaneously support bulk transmission and distribution level objectives. To accomplish this we developed a reference hierarchical control implementation, the FRS, that employs a distributed, hierarchical coordination approach designed based on desirable architectural principles. The implementation of the FRS has three distinct controllers that interact in a temporal hierarchy to manage a single substation's power flow consistent with wholesale market timelines. These controllers comprise only the FRS, shown in Fig. 1, controllers for the FRS Coordinator, Transactive Market Manager, or any aggregators are not detailed in this work. The first controller is a scenario-based stochastic Day-Ahead optimization that determines the offers made to transmission markets. The second controller is a model predictive controller (MPC) that is used to determine the base setpoints of DER and their respective reserve allocations as well as the marginal price for electricity for the substation's load. The final controller is a proportional-integral-derivative (PID) feedback control loop that proportionally dispatches the allocated reserves to manage substation power to the dispatch target. Fig. 2 shows the timeline of interaction for the hierarchical controls, which are based off of the California Independent System Operator's wholesale markets [11]. It displays a two-day operating period, the second of which is the operating day under consideration, visual representations of the horizons of optimizations, and when information is sent and received from DER and aggregators interacting with the controllers. It also depicts gate closure which is the point at which an optimization will need to be completed in order to influence the operating day's or hour's bid in a wholesale market. The reference control software is developed as an application for GridAPPS-D, an open-source platform for the development and deployment of portable applications for advanced distribution management and operations [12].

A. Day-Ahead Stochastic Optimization

The Day-Ahead process determines an optimal scheduled firm substation power and reserve-based ancillary service offer for wholesale markets. It is implemented as a scenario-based stochastic optimization to ensure that the system can provide the firm offer in nearly all possible uncertainty scenarios despite only a fraction of the overall power flow being directly managed. The scenarios used in the optimization are selected via a clustering algorithm from ten thousand scenarios drawn from the distributions of random variables to create a computationally tractable problem. The random variables include the nodal loads in the distribution circuits, the maximum and minimum available DER Power and Energy, the number of vehicles disconnecting in electric vehicles (EV) aggregations, self-discharge and efficiency parameters for demand response (DR) modeled as battery equivalents, wholesale prices for energy and ancillary services, and nodal dispatch inside DER aggregations. The distributions of the random variables are determined by external probabilistic forecasts.

The general form of the stochastic optimization is:

$$\min_{u(t)} E\big[\text{Total Cost}\big]$$

subject to: $\forall s \in N_{scenarios}$

$$\big[\text{DER Power (P \& Q) and Energy Constraints}\big]_s$$
$$\big[\text{Price-Responsive Load Equations}\big]_s$$
$$\big[\text{Linearized AC Power Flow}\big]_d$$
$$\big[\text{Power System Constraints (Voltage and Thermal)}\big]_s$$
$$\big[\text{Consistent Substation Energy and Reserve Offers}\big]_s$$

where: $\forall g \in N_{DER}; \forall t \in T$

$$u(t) = [P_{g,t}, Q_{g,t}, \rho_{up,g,t}, \rho_{dn,g,t}, \Pi_{dist,t}]_s$$

The problem is formulated as a quadratic program with a 24-hour horizon optimization and 1-hour granularity. The objective is formulated as an expected cost for serving the load in the network across all scenarios. The decision variables,

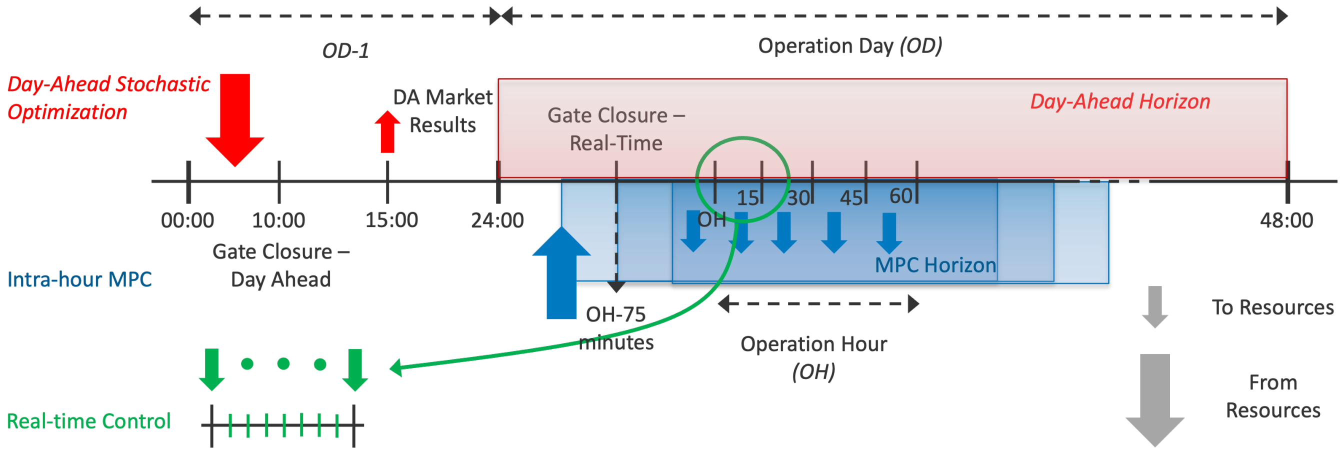

Fig. 2. Operational Timeline for FAST-DERMS Controls

$u(t)$ are the real power P, reactive power Q, up reserve ρ_{up}, and down reserve ρ_{dn} for each DER or aggregation as well as the electricity price, Π_{dist}, in the distribution network. There are power and energy constraints for aggregations of DER such as batteries, photovoltaics (PV), EVs, DR, and piece-wise linear expressions relating price to responsive demand. The optimization is network aware using a three-phased variant [13] of the linearized branch flow equations in [14]. Line losses are included in the objective, but are ignored in the power flow equations. Power flow is constrained by ANSI voltage limits and steady-state thermal line limits. Power flow is computed both with and without the reserves from DER actuated to ensure that deploying the reserves will not result in violations. The final set of constraints are critically important to ensure service offers to the transmission system are firm. They are formulated as soft constraints of the power flow through the substation and the total reserve offers such that they are equal across all N_{scen} scenarios.

B. Model Predictive Controller

The goal of the MPC is to determine initial power setpoints and reserve allocations for each DER that will be used in the real-time controller to meet market obligations. The MPC has a very similar mathematical structure to the Day-Ahead problem, but with a few small adjustments. First, the MPC is run as a deterministic problem to meet computational time requirements of the application, which we have assigned as an execution time less than 5 minutes. Changing the optimization from stochastic to deterministic is accomplished by adding an additional balancing reserve requirement that is computed based on the uncertainty in the forecast of load and PV. Next, the soft constraints on substation power and wholesale reserve commitment across the scenarios in the day-ahead process are modified such that they are constraining the MPC to the IS0 market awarded substation power and reserves. The error in these soft constraints become the primary objective to be minimized in the MPC. Last, it initializes the resource states with telemetry coming from the DER/Aggregators, and when that is not available it uses the best modeled information from previous optimization runs. The MPC is then run every 15 minutes, providing its guidance to the real-time controller for the actual dispatch.

C. Real-Time Controller

The design ethos behind the real-time controller (RTC) was to keep it as simple as possible so that it might be sped up to respond to a 4-second frequency regulation signal in future applications. To that end, a simple PID is applied to minimize the error between an ISO dispatch signal and the measured substation power flow to the sub-transmission network. This simplifies communications, as the real-time controller does not rely on feedback from all of the DER, only from the substation meter. The output signal of the PID is then disaggregated as a proportional change to the existing setpoints for each DER based on the reserve allocation that they received from the MPC. If the new setpoint assigned to the DER would be outside the range indicated by the sum of their MPC setpoint and reserve quantities, then they are sent a setpoint that is at that saturated maximum or minimum power, and the remainder is then allocated among the unsaturated DER. The interval at which setpoints are calculated and dispatched to the resources is a configurable parameter, and for testing in simulation it has been set to one minute.

IV. Sample Results and Discussion

The present section discusses sample results from a small test system to highlight features of the approach. Note that the key to scalability of the proposed architecture is decomposition of the distribution management problem into more tractable sub-problems at distribution substations. While this test system is small, the approach has scaled well into larger, realistic distribution feeders and the decomposition will allow for easy scaling to larger regions.

A. Simulation Setup

Simulations were performed on the IEEE 13-bus reference feeder [15], the network is shown in Fig. 3 which depicts

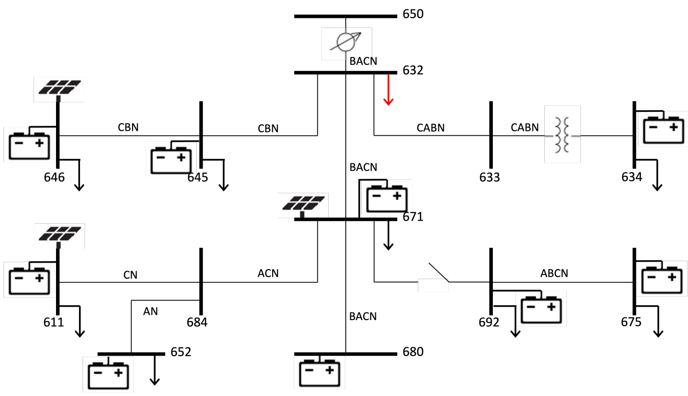

Fig. 3. The IEEE 13 test feeder indicating bus locations of DER.

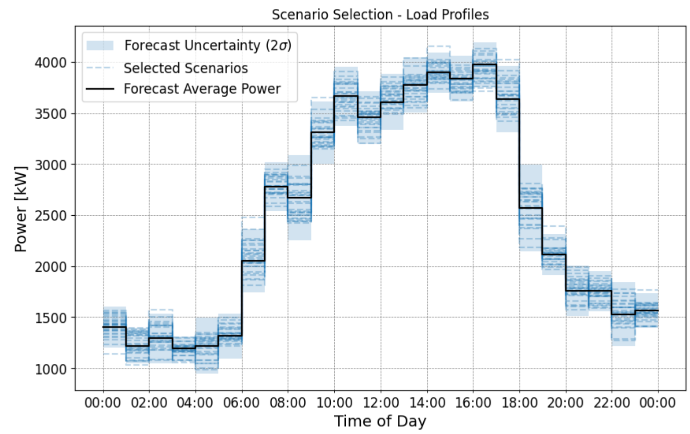

Fig. 4. Day-ahead probabilistic load forecast including the scenarios selected for stochastic optimization.

the phases present on each line and the location of the loads and other devices. Two types of DER are deployed across the feeder, PV and Batteries. There are three PV resources totalling 850kW of capacity, three battery aggregators managing batteries across 11 network locations with a total capacity of 560 kW, and two utility managed batteries totalling 840 kW. The probabilistic hourly forecasts of PV availability and nodal load were obtained based on smart meter data from an Iowa Utility and scaled such that the 75th percentile was equivalent to the point loading in the IEEE 13 reference case, a total of 3,466 kW. The load forecast is shown in Fig. 4, which includes an hourly average value in black and a light blue region around each average representing the gaussian forecast uncertainty (2σ). The same 5-minute data source was sampled to generate load and PV profiles that then underwent the same scaling as the forecast data. Weather and solar insolation data used for the forecast and sampling for the simulation was from April first, a weekday. To get the reactive power load time series, the nodal ratio between real and reactive power was held constant from the reference case. As the simulator requires a single load profile that is applied to all buses and phases, the nodal load had the same proportional shape across the feeder.

The native GridLAB-D simulation available in GridAPPS-D was used to simulate a 4-hour window in which the MPC and real-time controller were operating with a battery aggregator, directly managed PV and utility scale batteries, and a mock ISO dispatch agent. The Day-Ahead stochastic optimization was run offline, and the market awards were assumed to be equivalent to the schedule generated by the Day-Ahead process. While the mock ISO sent dispatches every five minutes, they followed the hourly schedule from the Day-Ahead award. Batteries were initialized in the simulation with energy states equal to the modeled energy states in the day ahead process.

B. Sample Results

The day-ahead stochastic scenario-based optimization determines the substation power and reserve offers to wholesale markets. In order to make a firm commitment of the energy and reserve offers, the scenarios selected need to adequately represent the range of values that uncertain variables can take. The more scenarios that are selected by the clustering algorithm, the higher likelihood that the the values are representative. Fig. 5 shows the impact of increasing the the number of scenarios from the single deterministic expected value case up to 50 representative scenarios on the optimal objective value and computation time. A deterministic optimization will have a lower objective value than a stochastic optimization averaging the cost of its multiple co-optimized scenarios. However, the deterministic solution is likely to be infeasible in real-time do to forecast errors. As such, we can consider the rate of change of the objective value as scenarios are added to be a measure of the improvement in the likely feasibility of the results. If adding more scenarios is not impacting the objective value, then the scenarios must adequately represent the uncertain problem space and the additional complexity is not needed. These results show that the objective value of the optimization increases sharply up to 10 scenarios, and then increases more gradually as more scenarios are added. Further, the graph shows a roughly linear trend in the computation time over this number of scenarios. This suggests clearly that 10 or greater scenarios should be used.

As the slope never drops to zero, we can look at how the profile of substation power changes as we add more scenarios, in Fig. 6, to get a better understanding of how this key result is impacted. The graph shows profiles darken in color as they increase the number of scenarios. We can see that the largest changes from the 50 scenario case occur in very lightly shaded profiles, and so there may not be a big impact in the offer at each hour as we increase the number of scenarios. This gives us confidence that at a relatively low number of scenarios, we can still be near enough to a feasible optimal result to expect the recourse in the MPC and real time controller to make up the difference and our overall offer will remain a firm commitment to wholesale markets.

We test this in simulation with 30 scenarios for the DA optimization problem. Fig. 7 shows the output of a four

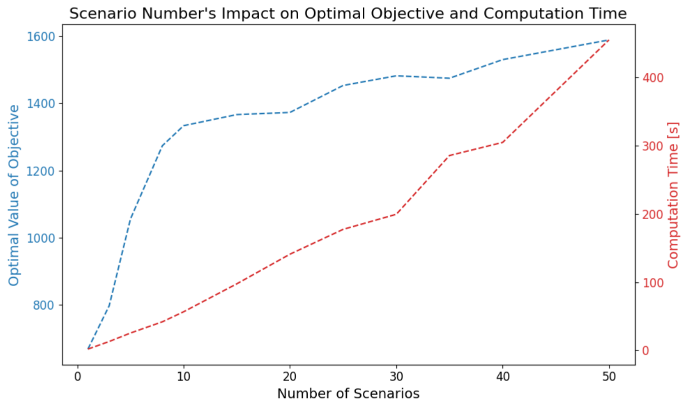

Fig. 5. The impact of the number of scenarios selected on the objective value and computation time.

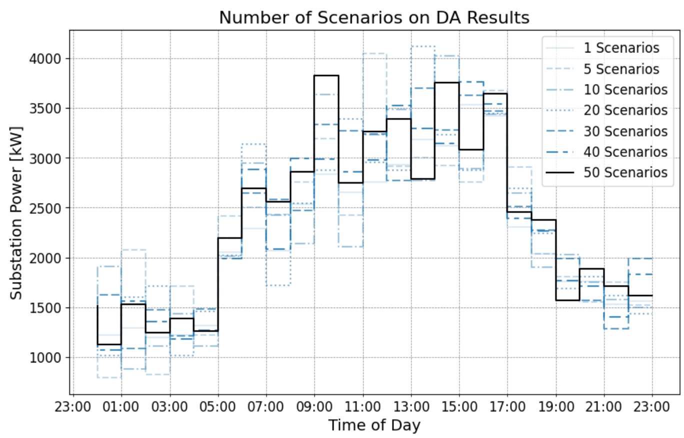

Fig. 6. The impact of the number of scenarios selected on the substation power profile in the day-ahead optimization.

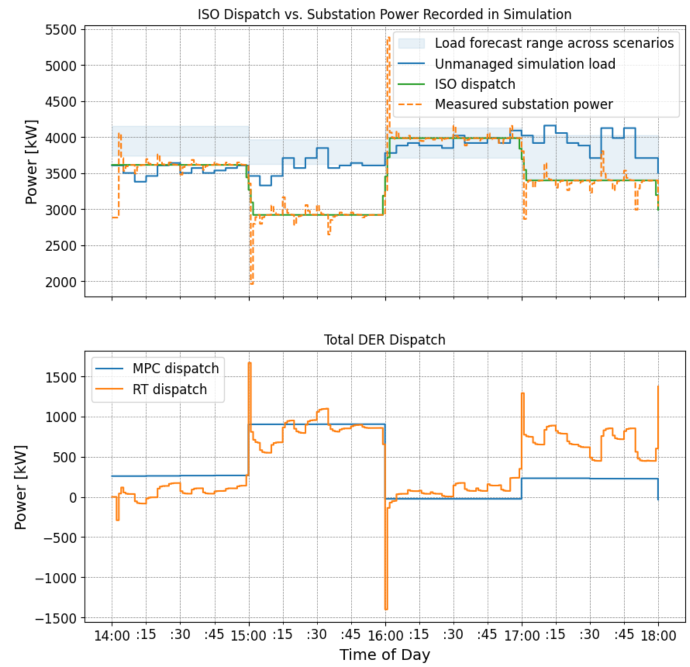

Fig. 7. Feeder power, ISO dispatch, and actual and forecast system load (top), and total DER setpoints (bottom) in simulation results of the FAST-DERMS controls.

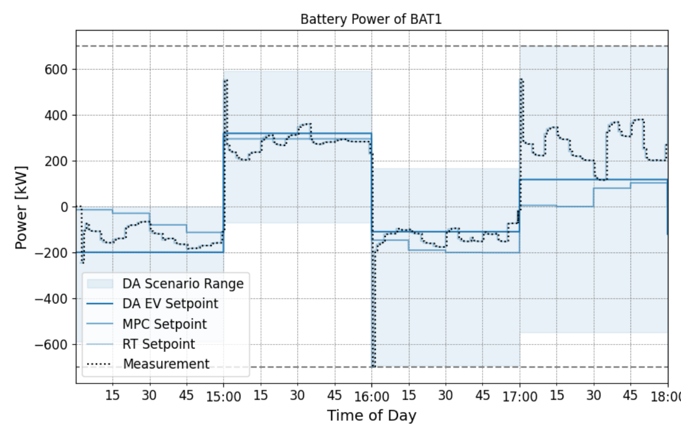

Fig. 8. Setpoints to the largest battery in the simulation from all levels of the FRS controls hierarchy.

hour simulation. In the upper graph, the orange line displays the substation power (in load convention) measured in the simulation against the green ISO dispatch. Additionally, the graph also shows the range of the load scenarios used in the stochastic optimization and the actual load profile used in simulation. The lower graph indicates the total of the DER power setpoints dispatched by the MPC as well as the aggregated dispatch that was sent to the DER by the real time controller, both in generator convention.

Overall, the tracking across the four hour simulation is good. We are able to obtain an average absolute error of less than 2% of the dispatch target. There is a sizeable difference between the RT controller and the MPC results. This is unsurprising given the large error in the forecast, however there are enough reserves available to compensate for it. While the overall tracking is good, there are still some areas for improvement in the results.

At each step change in dispatch, the real-time controller has a large overshoot that is quickly damped. As the dispatch only changes significantly on an hourly basis, this isn't a large issue for these results, but if the dispatch was changing on a 5-minute basis or faster this overshoot could have a larger impact on the error. We also see that the remainder of the tracking error is due to the 5-minute changes in the simulated load, which are quickly managed. Additionally, the formulation doesn't prevent curtailment of PV resources, which can be high as 50%. Curtailment should be treated as a last resort, but as the PV availability is a random variable, the optimal outcome may rely on curtailment to ensure firm service provision across all possible PV scenarios. Additional disincentives for curtailment, such as the payment of an opportunity cost to the generator owner, in the objective may be necessary to minimize it in the results.

Fig. 8 highlights some additional features of the temporal hierarchical control. It shows a single resource's (a large battery's) power setpoints recorded in each layer of control. In the day-ahead process, each scenario in the optimization is free to dispatch the DER differently, so the light blue shaded area represents the range of those setpoints. Their range is large as the optimization is relying on the battery resources to manage the problem's uncertainty. The graph also shows the day-ahead setpoint selected for a scenario composed of only mean forecast values, the setpoint selected by the MPC, the real-time controller setpoints, and the resource's output as recorded in simulation. The day-ahead dispatches the individual resources with a wide range, which is inclusive of the MPC's dispatch. The real-time control often deviates substantially from the MPC results due to forecast error. We also see that MPC results tend to change every 15 minute inside the hour even though the network dispatch has remained the same. This is partially due to the unplanned changes to battery state of charge caused by the real-time control. This simulation highlights the ability of each layer of FRS's temporal hierarchy to provide an opportunity for recourse to manage forecast error.

V. Concluding Remarks

The work presented here describes a possible solution for scalable management of high penetrations of DER to provide simultaneous distribution and transmission level services, called the Federated Architecture for Secure and Transactive Distributed Energy Management Solutions (FAST-DERMS). The approach employs a "Total DSO" architectural methodology to manage the complexity of computation for centralized system operators, reduce the communications frequency and volume, and avoid reliability risks caused by tier bypass. The FAST-DERMS architecture also reduces the cost of monitoring and measurement for grid service provision and simplifies the transmission / distribution interface by defining and measuring transmission grid services at the distribution substation. A reference controls implementation is described that is composed of three hierarchical layers of control and optimization. First, there is a day-ahead, scenario-based stochastic optimization used to make market commitments. Second, there is a model predictive controller that determines the base setpoints and balances reserve allocations for DER. Lastly, there is a simple PID-based real time controller that regulates substation power to the dispatch level sent by the transmission system operator.

Sample results in a small test feeder are presented to showcase the control's capability. We present results to provide insight into the firm day-ahead service offers of energy and reserves at a distribution substation, and show that despite unanticipated forecast errors the hierarchical approach provides enough recourse to make up for those errors. Over a four hour simulation, the average absolute error is maintained below 5% of the dispatch value at the substation.

FAST-DERMS is an ongoing project with planned future work, including: documentation of the control performance on full-utility scale feeder models; improvements to the real-time dispatch algorithms and optimization formulations to reduce PV curtailment; demonstration in a laboratory environment interacting with an enterprise advanced distribution management system (ADMS); and extension of the architecture and controls approaches to support direct access for aggregators to transmission markets, bypassing direct management from distribution system operators.

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