Community-Based Transactive Coordination Mechanism for Enabling Grid-Edge Systems

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***Abstract*—The changing landscape of the electricity industry, characterized by a surge in distributed energy resources (DERs) and proactive customers, necessitates practical solutions for coordinated operation especially at the distribution-level. This paper introduces a community-based transactive coordination mechanism designed to incentivize customers for providing localized and system-level services reflected through real-time prices. The work presents a bidding approach for communities, representing collectives of customers, to formulate their price-responsiveness for retail energy coordination, thereby emphasizing a community-centric model. By sending bidding curves to a third-party, the mechanism enables customers with DER assets to actively participate in localized coordination with the Load Serving Entity (LSE), thereby supplementing each other's and even the utility's needs through a shared energy economy. The proposed transactive mechanism is implemented leveraging a co-simulation framework that integrates a distribution grid simulator with control agents for performance evaluation. Simulation-based evaluation on a real distribution system use-case, in collaboration with a local utility, demonstrate the potential of the mechanism to reduce costs by 12% for communities with DERs like solar photovoltaic (PV) and battery energy storage systems (BESS).**

***Index Terms*—Community-based coordination, grid-edge systems, retail market, shared energy economy, transactive energy.**

I. Introduction

THE electricity industry is undergoing significant changes due to the proliferation of distributed energy resources (DERs), planned roll-out of smart metering, and favorable regulations [1]. These changes are inducing a transformation of a large share of electricity consumers into "prosumers" who can proactively manage their consumption, production, and energy storage [2]. The changing landscape introduces new challenges for utility operations and business models. From an operational perspective, the distribution utility faces a large number of these grid-edge resources for which it currently has limited to no visibility or control [3]. From a business perspective, utilities have to plan for infrastructure to accommodate their variability & unpredictability and devise retail electricity rates to influence customer decisions without directly controlling the resources [3]. However, the enhanced flexibility from DERs, if appropriately controlled, can provide strategic opportunities for customers to actively participate in distribution-level coordination and reform their energy practices towards more consumer-centric economies [4].

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Towards leveraging the flexibility of DERs, utilities are actively reforming existing market structures and tariff-designs to incentive customer participation. Some utilities have introduced mechanisms like demand charges [5] and time-of-use (TOU) price to incentivize customers for shaping their consumption based on historic trends of grid requirements. However, such mechanisms do not reflect the instantaneous system needs which may lead to situations where customers have to pay more than they would under flat tariffs [6]. Transactive energy (TE) is an emerging alternative for coordinated operation of DERs [7]. TE systems present market-based control techniques for coordinating self-interested parties through exchange of information captured in transactions. Historically, TE implementations have mostly been used with centralized price discovery mechanisms, based on the top-down approach of conventional electricity markets [8], [9]. In such architectures, customers behave as passive 'price-takers', using their flexibility for incentives based on the system requirements [10]. However, a localized community-based TE structure can instead allow a bottom-up approach that empowers consumers to proactively trade energy for supplementing each other's and even the Utility's needs through a shared energy economy, thereby actively managing their energy usage.

Some existing studies in the literature have presented the application of TE systems for community-centric coordination [11], [12], and demonstrated the potential of such community-based coordination schemes in enhancing grid efficiency, cost-effectiveness, and community benefits. The study in [11] presents a distributed community-based market structure enabled through a supervisory third-party that simplifies the interface between community members and the system operator. The work in [12] presents TE-based coordination mechanisms for Day-Ahead (DA) and Real-Time (RT) community-based retail markets. Towards the adoption of such coordination schemes, existing studies are somewhat limited in terms of applicability to a diverse set of DERs (like batteries and solar PVs), incorporation of real-life uncertainties (like forecasting errors), and demonstration of their value as compared to existing tariff structures. Battery energy storage systems (BESS) and solar PVs are becoming more popular due to their ability to increase the flexibility of customers and lowering capital costs. Hence, it is imperative to effectively integrate these flexible assets into TE coordination schemes towards reflecting the future of customer-centric grid-edge systems.

Building upon existing concepts, this paper presents a transactive coordination framework for enabling communities to participate in localized energy trading. The framework presents a bidding strategy for communities with DERs like BESS and PVs to represent their price-responsiveness along with a centralized community economic dispatch problem to facilitate real-time market-based coordination between the communities within the Load Serving Entity (LSE). The proposed coordination strategy is implemented using a co-simulation platform, that integrates a distribution grid simulator and Python-based control agents, to provide a practical transactive community market structure that aligns with the evolving needs of the electricity industry. Through simulation results using a real distribution system, the study provides a comparative evaluation of the economic benefits of such community-based coordination with respect to existing tariff and rate structures.

II. Transactive Coordination Architecture

Community-based retail market designs aim to provide a structured organization for enabling active customer engagement in localized energy sharing. The coordination architecture comprises the LSE and the communities (referred to here as community districts), which are interfaced through a supervisory entity. This entity enables customers to represent their responsiveness and coordinates dispatch of underlying assets based on market-cleared values. The operational strategies of each layer are discussed in detail in the following subsections.

A. Community Districts

Within the transactive coordination framework, community districts serve as the foundational units of operation. These districts are typically defined by geographic or organizational boundaries and represent the building blocks of the community-centric market structure. Each district may consist of an individual customer (e.g. large commercial & industrial) or group of customers (including an aggregate of residential & small commercial), sharing resources within the district and participating in localized energy trading as a unit. The primary goal of these districts is to foster localized cooperation and harness mutual benefits by facilitating the exchange of surplus energy, thereby enhancing grid efficiency.

The customers within a community district operate a diverse set of DERs, including PVs and BESS. These DERs provide enhanced flexibility with their capacity to generate electricity, store excess energy, and provide power back to the grid. To maximize the value of these resources, communities employ optimization-based scheduling utilizing predictive models to manage their DERs efficiently. By doing so, the flexibility of their resources can be aligned to minimize energy cost of the community and optimize self-consumption based on forecast estimates of both grid and customer's requirements. In order to account for forecasting errors and instantaneous demand of the customers, the scheduling process is supplemented with real-time flexibility estimation. These processes, in a combined way, enable an economically efficient utilization of the flexibility while considering the customer's preferences.

1) Optimization-based Scheduling: Community-specific scheduling strategies take into account a range of variables, such as energy demand patterns, weather forecasts, real-time energy prices forecasts, and availability of assets. An example optimization is shown below in (1a), the objective being to minimize the total cost of energy throughout the horizon (here 24 hours) based on forecasting estimates of energy demand, PV generation, and energy prices. This would facilitate aligning the availability of flexible resources to optimize consumption and minimize costs of operation.

$$\underset{\hat{Q_{c,t}}}{\text{minimize}} \sum_{t=1}^{T} [P_t^{forecast} \times Q_{c,t}] \tag{1a}$$

$$Q_{c,t} = Q_{Load,t}^{forecast} + Q_{PV,t}^{forecast} + Q_{BESS,t} \tag{1b}$$

$$0 \leq Q_{BESS,t}^{+} \leq Q_{BESS,t}^{max,+} \quad \forall t = 1, ..., T \tag{1c}$$

$$0 \leq Q_{BESS,t}^{-} \leq Q_{BESS,t}^{max,-} \quad \forall t = 1, ..., T \tag{1d}$$

$$Q_{BESS,t} = Q_{BESS,t}^{+} - Q_{BESS,t}^{-} \quad \forall t = 1, ..., T \tag{1e}$$

$$q_{batt,t} = \frac{Q_{BESS,t}^{+}}{\eta^{+}} - Q_{BESS,t}^{-}\eta^{-} \quad \forall t = 1, ..., T \tag{1f}$$

$$l_t = l_{t-1} - \frac{1}{E_s} q_{batt,t}; \;\; \underline{L_t} \leq l_t \leq \overline{L_t} \quad \forall t = 1, ..., T \tag{1g}$$

$$l_{desired} \leq l_T \tag{1h}$$

Where, $P_t^{forecast}$ is the energy price forecast and $Q_{c,t}$ is the scheduled power exchange between the community and grid during hour t. In (1b) the community can be represented by the aggregate of forecasting demand, PV, and battery schedules. For the chosen use-case, the proposed formulation models the customer demand as inflexible loads. However, demand flexibility can be simply incorporated through additional temporal constraints. Bounds of the BESS power exchanges with grid are considered in (1c) and (1d) with $Q_{BESS,t}^{+}, Q_{BESS,t}^{-}$ being the power injection/withdrawal into/from grid respectively and $Q_{BESS,t}^{max,+}, Q_{BESS,t}^{max,-}$ being the inverter capacity limits. In addition to expressing power transfer between the BESS and the grid in (1e), (1f) calculates the rate of change of energy in the BESS, with $q_{batt,t}$ being power input to the battery at the end of hour t. Finally, constraints (1g) models the state-of-charge (SOC) within the BESS and (1h) enables the BESS to maintain a desired SOC at end of the scheduling horizon.

2) Real-Time flexibility: To enable localized energy sharing, communities participate in the trading process by providing their price-responsiveness through bid curves that depict their willingness to buy or sell electricity at different price-levels and quantities. These curves reflect customer preferences, allowing them to tailor their participation to meet specific goals, such as cost savings or energy self-sufficiency.

The RT bidding strategy is formulated to represent the community's flexibility considering the uncertainties in price and demand. Figure 1 presents a sample bid curve for a community, where $\hat{Q_{c,t}}$ represents the operational preference of the community scheduled for the price forecast ($P_t^{forecast}$). While accounting for forecasting errors, this is achieved by adjusting the battery schedules with the difference between

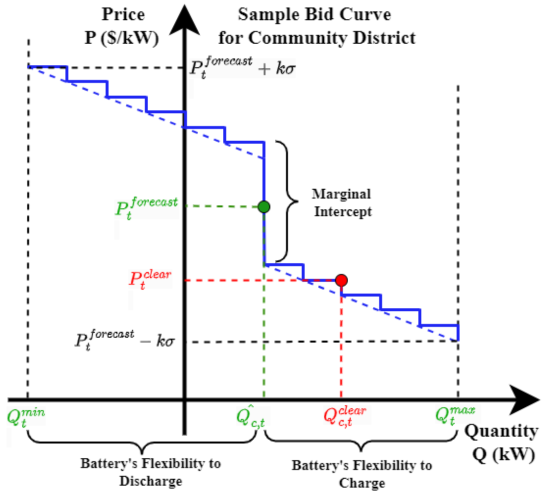

Fig. 1. Sample Bid Curve for a Community District at a RT interval.

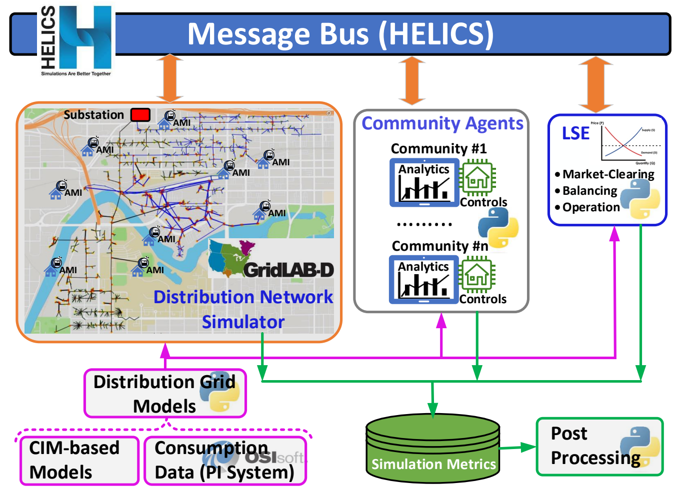

Fig. 2. Overview of the co-simulation platform.

the forecast value and the actual consumption measured during last interval. The flexibility of the district is modeled in terms of the BESS's maximum ($Q_{BESS,t}^{max,+}$) and minimum ($Q_{BESS,t}^{max,-}$) available capacity which provides the operational range of the community district. Motivated from [13], the bid-curve design consists of a marginal intercept (see Fig. 1) that provides some robustness with respect to the small variations of prices. The maximum and minimum values for bid price are determined through using $k * \sigma$, where σ is the standard deviation of the historical prices and k is a slider setting that represents the preferred degree of adjustment with respect to the instantaneous price variation. The range of price and quantity values are mapped in a piece-wise fashion to represent the district's bid curve, for which at any point along this range Q the district will be willing to arbitrage energy at. During each 5 minute interval, the bid curves are submitted to the market coordinator for determining the cleared prices and operation state for each community district.

B. Load Serving Entity (LSE)

Effective integration with the LSE is essential for community-based coordination, as it will not only increase the visibility and control for system operators but will also facilitate the LSE in energy arbitrage at wholesale markets. This is achieved by incorporating the LSE as an active participant in the negotiation process to provide an energy surplus at the RT energy procurement cost. For the chosen use-case, since the utility participates in a wholesale energy imbalance market (EIM) [14], the energy costs are represented through the RT-prices obtained from EIM. During each settlement interval, the LSE bids an energy surplus (capacity-based) at the RT-price to support any additional demand of the communities. This would enable the community-based market design to be effectively integrated with existing market constructs which is expected to facilitate the adoption of such-markets.

C. Market Coordination

The market coordination mechanism is responsible for coordinating the interaction between communities & LSE, managing energy transactions and settlements. The market facilitator collects the bid curves from the stakeholders to determine the optimal dispatch of resources based on the following optimization formulation:

$$\underset{Q_{LSE},Q_c^j}{\text{minimize}} \;\; \left(P_t^{actual} * Q_{LSE,t}\right) - \sum_{j=1}^{N} Cost^j(Q_{c,t}^j) \tag{2a}$$

$$\text{Subject To:} \quad Q_{LSE,t} + \sum_{j=1}^{N} Q_{c,t}^j = 0; \tag{2b}$$

$$Q_{LSE,t} \geq 0; \quad Q_{c,t}^{j,min} \leq Q_{c,t}^j \leq Q_{c,t}^{j,max} \tag{2c}$$

Where P_t^{actual} & $Q_{LSE,t}$ represents the LSE's price and quantity, $Cost^j(Q_{c,t}^j)$ represents the cost function, and $Q_{c,t}^{j,min}$ & $Q_{c,t}^{j,max}$ is the operational range of the community j. Please note that the optimization in (2) is a mixed integer problem as $Cost^j$ is piece-wise linear curve. The optimization process results in cleared price & allocation ($P_t^{clear}, Q_{c,t}^{j,clear}$), which are communicated back to communities for dispatch. This transactive coordination approach ensures aligning the preferences of individual community with the collective goals of the community districts and LSE, thereby enhancing cost-effectiveness and the overall efficiency of energy distribution.

III. Modelling & Co-Simulation Platform

A. Distribution Grid Models

To implement the proposed coordination mechanism in a close-to-realistic scenario, the distribution grid models were developed through a model-driven engineering approach utilizing the Common Information Model [15] as the domain information model that standardizes & integrates data extracted from the utility's existing enterprise systems as indicated in Fig. 2. These models were translated into native simulator-compatible models using a conversion toolkit and validated based on actual measurements, further details of which are presented in [16]. The feeder models were supplemented with actual consumption profiles, extracted from meter-data historian [17], and played in during the simulation to emulate realistic operational conditions for the community customers.

B. Co-Simulation Framework

The proposed transactive coordination mechanism is implemented using a co-simulation platform, shown in Fig. 2. The different layers of the platform are discussed here:

a) Community District Agent: This agent coordinates the customer assets in the community (shown in Fig. 2). The agent determines the operational schedule of DERs based on forecasts based on (1), and formulates RT bid-curves which are communicated to the market facilitator. During operation, the community agent receives the cleared allocation and dispatches the underlying DERs.

b) System Operator - LSE: The LSE is implemented as a self-contained agent in Python which provides the energy surplus at the RT energy procurement cost and facilitates emulating the market clearing process, sending market-cleared price and allocation to the community district agents.

c) Distribution System Simulator: The distribution system network is modeled using GridLAB-D™ [18]. BESS operations are incorporated using GridLAB-D's battery and grid-forming inverter models. During operation, the BESS are controlled by the community district agent which sends out target setpoints based on market cleared allocations.

d) Information Exchange: The co-simulation architecture is implemented using Hierarchical Engine for Large-scale Infrastructure Co-Simulation (HELICS) [19] that allows time-synchronized information exchange among the simulator and the agents (shown as the message bus in Fig. 2).

IV. Use-Case Description

The proposed framework is simulated on a real-world distribution system located in the pacific northwest, and operated by Avista Corporation. Fig. 3 shows the footprint of the 13.2-kV distribution feeder with each community district highlighting its service area and their point of common coupling (PCC). The feeder model has been derived and validated from data directly available from the utility enterprise systems [16]. The coordination scheme is implemented among three community districts and the specifications of all district assets are given in Table I. The District 1 represents a pair of commercial customers with an operational Solar PV and BESS connected to their premises. Districts 2 & 3 represents a mix of commercial and residential customers with the DERs assets that were chosen based on potential future deployment scenarios.

The proposed coordination scheme is implemented for community district agents, where they would schedule their underlying DERs based on forecasts based on (1a) and provide their RT bid curves for market-based coordination. In order to comparatively evaluate the economic benefits of such community-based coordination with respect to existing tariff and rate structures, a base-case, where the district assets are not dispatched, is simulated along with a set of additional tariff scenarios that are further discussed below:

1) Schedule 21 Coordination: Without any market-based coordination, the community with DERs would operate under a Schedule-21 [20] and would want to optimize their DERs to minimize their lower operating costs. The Schedule-21 tariff includes a constant energy price and a demand charge based on the peak demand hour each month. Based on the tiered category of the net demand of the communities, the Schedule-21 energy price and demand charge is considered to be \$0.07535/kWHr and \$7/kW respectively. To optimize the operation of the assets under this tariff scenario, the objective function of scheduling problem is modified with an additional term, as given by (3), where $Q_{c,t}^{j,max}$ represents the estimated maximum demand value of the district for the 24h interval.

$$\underset{Q_{c,t}^{j}}{\text{minimize}} \sum_{t=1}^{T} \left(\$0.753 \times Q_{c,t}^{j} + \frac{7}{30} Q_{c,t}^{j,max} \right) \tag{3}$$

Since the scheduling problem is solved over a 24 hour horizon, the monthly demand charge rate is translated to a daily value to simplify the comparative evaluation of benefits with respect to other scenarios. In this case the district's assets will not be able to arbitrate energy, but will be able to schedule themselves to lower their operational costs.

2) Prices-to-Devices Coordination: This scenario aims to model a dynamic pricing scenario, where the communities would be billed based on the RT energy procurement cost of the LSE. Since the Utility partner participates in an wholesale EIM [14], the RT prices chosen for this scenario were based on the average RT locational marginal price (LMP) of the EIM's load aggregation points (ELAP) representing the LSE's localized cost of energy procurement. Although, the prices-to-devices scenario does not allow for energy trading between the

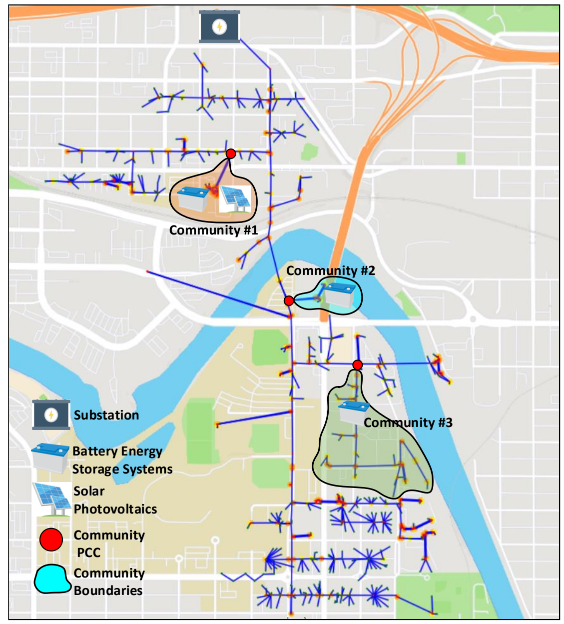

Fig. 3. Schematic of the test system along with the community boundaries.

TABLE I
SPECIFICATIONS OF THE DER ASSETS IN COMMUNITY DISTRICTS

District Area	Asset Type	Asset Capacity	Inverter Efficiency	Inverter rating
District 1	PV	254.35 kW	0.98	254.35 kW
District 1	Battery	1320 kWHr	0.95	660.00 kW
District 2	Battery	334.8 kWHr	0.95	168.15 kW
District 3	Battery	334.8 kWHr	0.95	168.15 kW

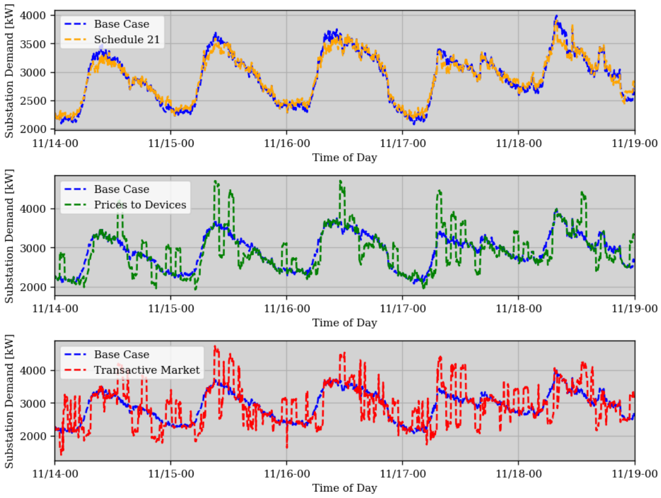

Fig. 4. Feeder Demand Reflecting Battery Optimization for Each Case.

community districts and LSE, the dynamic pricing enables the communities to schedule their DERs and utilize their flexibility based on grid requirement in lieu of economic-benefits.

3) Transactive Community-based Coordination: This scenario implements the proposed transactive community-based coordination mechanism. The communities would communicate their RT flexibility curves and the LSE would provide an energy surplus based on the RT-LMPs from the EIM (as discussed above) to participate in the energy trading process. Finally, the communities would dispatch their DERs based on the optimal allocation and price determined through market-based coordination between the districts and the LSE.

V. Results & Evaluation

The proposed use-case is evaluated for the different tariff-based coordination scenarios over a duration period of 5 days in November 2022. Figure 4 presents the impact for each of the coordination scenarios on the net feeder demand with respect to the base case. The Schedule-21 scenario enables the communities to operate their BESS to optimally reduce their demand charge and therefore operational cost. The prices-to-devices and transactive cases impose dynamic pricing on the communities, enabling them to utilize their flexibility based on the instantaneous system needs reflected through RT-LMPs. This yields certain intervals of higher demand when the RT prices are relatively low along intervals of lower demand when the prices are high.

To further illustrate the energy trading events for the community-based coordination mechanism, Fig. 5 presents the transactive interaction between districts. Since the districts are restricted to export energy back to the LSE, the negative demand in District 1 during certain intervals signifies energy trading among the districts, with District 1 providing energy to other districts due to the larger availability of BESS, thereby locally balancing each other's needs. In contrast, the prices-to-devices scenario does not allow localized energy sharing, hence the coordination aims at scheduling the resources with the varying LMPs such that the aggregated demand of the districts is close to zero during high price intervals (see Fig. 5).

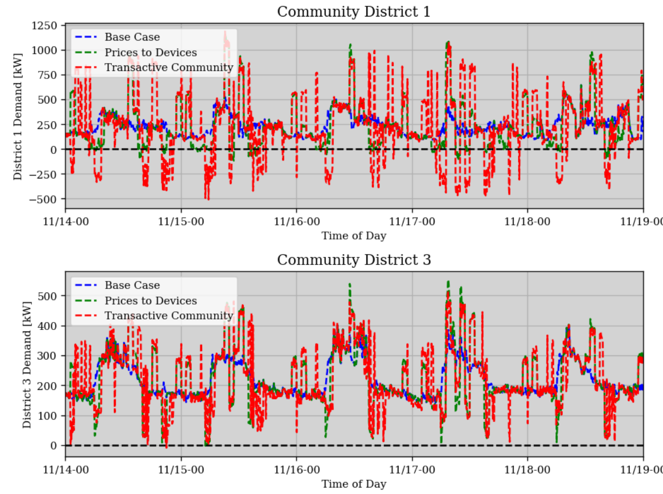

Fig. 5. Net demand of District 1 & 3 measured at PCC over 5-day simulation.

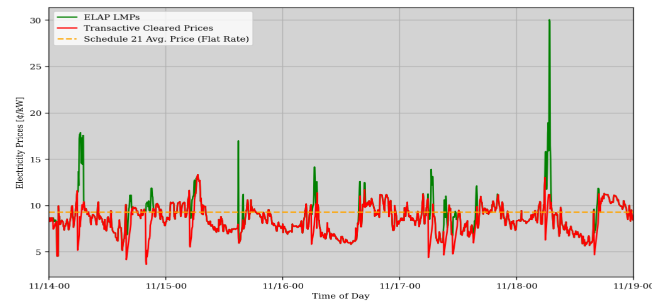

Fig. 6. RT LMPs and market-cleared prices over the 5-day simulation.

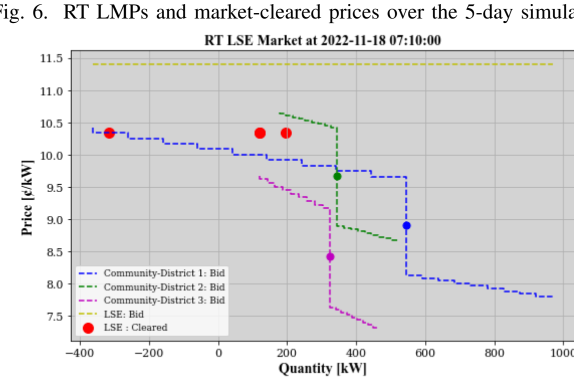

Fig. 7. Bid curves from Communities & LSE for a sample market interval.

Figure 6 provides a visual representation of the RT LMPs along with the community-based market-cleared prices. The cleared prices for the community-based transactive case indicate that for certain intervals the community-based market cleared prices are lower than the RT-LMPs. These are intervals when the LSE price (RT-LMPs from EIM) were relatively higher (either from the foretasted value or the local market cap) and the coordination mechanism would facilitate energy trading between the districts. During such intervals, the community districts would coordinate with each other for localized energy sharing, i.e. a district utilizes their bid flexibility to serve the energy needs of the nearby districts at a lower cleared price. Figure 7 presents the bid curves for a sample market interval where the LSE price was relatively higher and District 1 was able to supply the energy needs for Districts 2 & 3 with a net-zero import from the LSE, enabling them

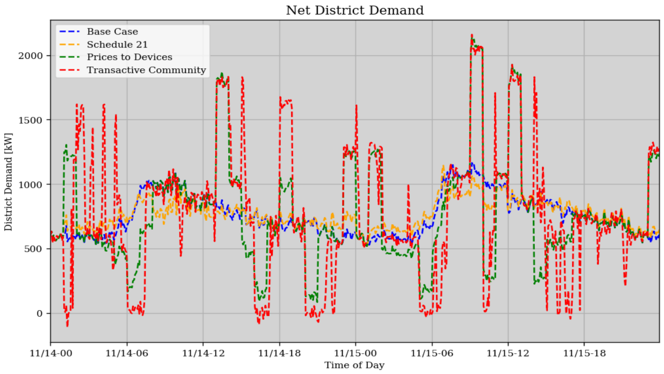

Fig. 8. Aggregated consumption of the three districts over 2 sample days.

TABLE II
OPTIMIZED DISTRICT CONSUMPTION COSTS OVER 5-DAY PERIOD

	Price Scenario	District 1	District 2	District 3	Total Cost
Base Case	Schedule 21	$2,802.38	$3,397.43	$2,447.91	$8,647.72
Case 1	Schedule 21	$2,679.96	$3,415.35	$2,437.17	$8,532.48
Case 2	Prices-to-Devices	$2,314.59	$3,357.54	$2,2547.28	$7,919.41
Case 3	Transactive	$2,277.54	$3,238.39	$2,161.48	$7,677.41

to operate at a relatively lower price. Figure 8 shows the net demand over a 2-day period with respect to each price scenario. The time intervals where the net district demand is close to zero indicate where there is no energy needed from the utility company, enabling communities to collaboratively and effectively operate as grid-edge systems.

To demonstrate the economic benefits of community-based coordination, Table II provides a detailed breakdown of costs for each community district under the different price scenarios. Results show that all the three cases demonstrate a reduction in the communities' net operational cost as compared to base-case, indicating the economic benefits of utilizing DER flexibility. The transactive case leads to a 12% reduction in the net operating cost for the communities as compared to 8.5% for the prices-to-devices cases thereby indicating the economic-benefits of community-based coordination mechanism.

VI. CONCLUSIONS

Towards enabling localized coordination through a shared energy economy, this work presents a community-based transactive coordination framework. The framework presents a scheduling and bidding strategy for communities with DERs like BESS to facilitate RT market-based coordination between the communities and LSE. Partnering with the local utility, the effectiveness of the mechanism is evaluated for a real-life use-case implemented using a co-simulation platform. The evaluation of transactive coordination demonstrated its impact on reducing overall energy costs for each of the community districts, showcasing the benefits of coordinated energy trading among districts. Simulation results demonstrate the effectiveness of community-based markets in coordinating the flexibility of grid-edge systems and reducing the operational cost compared to existing pricing structures.

Future work includes extending the framework to incorporate the flexibility of the thermal storage-based resource and deploying the mechanism for field-testing. While this work demonstrates the use-case of arbitrage as a service, changes to agent objective functions can be extended to include other ancillary services (such as Volt-VAR support, spinning reserve, etc.). Incorporating the recovery of fixed costs for energy delivery presents another avenue for future research.

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