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Cooperative Game Theory for Grid Service Pricing: A Utility-Centric Approach

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This study presents a novel alternative to traditional Net Energy Metering (NEM) by proposing a set of innovative pricing schemes for solar customers participating in utility-led grid service programs through the aggregation of Distributed Energy Resources (DERs). Grounded in cooperative game theory, the proposed framework facilitates equitable and efficient value allocation among key stakeholders, namely customers, utilities, and aggregators—based on their respective marginal contributions to grid performance and system cost reductions. In contrast to legacy NEM structures, which typically remunerate customers at retail rates and inadequately incentivize storage adoption, load flexibility, or temporal optimization, this approach enables new revenue opportunities by embedding DERs within coordinated grid service portfolios. The pricing mechanisms developed herein are centered on two critical grid services: energy arbitrage and peak load management. These services are provisioned by the excess capacity of customer-owned DERs, particularly rooftop photovoltaic systems and behind-the-meter battery storage. Through the implementation of a Grid Services Set (GSS) and a complementary Grid Services Rider (GSR) tariff structure, participating customers voluntarily permit automated utility coordination of their devices in return for performance-based compensation. An integrated optimization algorithm co-optimizes DER dispatch across both distribution-level operational requirements and real-time wholesale market opportunities, such as those found in the Energy Imbalance Market. This enables strategic charging during periods of surplus or negative pricing and discharging during price peaks. The proposed model contributes to the advancement of Non-Wires Alternatives (NWAs) by reducing reliance on conventional infrastructure upgrades and enhancing grid flexibility and resilience. It also offers a regulatory-aligned pathway for harmonizing DER integration with utility planning objectives, renewable energy targets, and climate adaptation strategies. By fostering a cooperative paradigm between utilities and customers, the framework promotes prosocial grid behavior, scalable DER participation, and innovation in the evolving landscape of decentralized energy systems.

List of Abbreviations:

- DER: Distributed Energy Resource
- GSS: Grid Services Set
- GSR: Grid Services Rider
- ISB: Integrated Service Bundle
- NEM: Net Energy Metering
- MSP: Marginal Supply Price
- AC: Avoided Costs
- CR: Customer Revenue (Compensation Rate)
- EIM: Energy Imbalance Market
- VoLL: Value of Lost Load
- LMP: Locational Marginal Price
- PBR: Performance-Based Regulation

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1. Introduction

The Grid Services Set (GSS) is designed to effectively leverage customer-owned Distributed Energy Resources (DERs) to enhance grid operational efficiency and reduce system-wide costs of service delivery [1]. This framework reimagines the role of customer DERs—such as rooftop solar, battery storage, and smart appliances—not as passive elements, but as dynamic assets that can contribute to real-time grid reliability and resilience [2].

In the proposed approach, residential customers voluntarily opt into an Integrated Service Bundle (ISB) authorizing automated control of their DER assets within a utility-managed framework that ensures consumer protection, incentivizes energy storage adoption, and facilitates scalable energy savings through home energy management systems. By providing a more integrated and dynamic mechanism for DER participation, the ISB approach seeks to address the shortcomings of existing policies, such as net energy metering (NEM). Traditional NEM programs, implemented through net metering tariff riders (NMR), compensate customers at the retail rate for the electricity exported to the grid. This has raised equity concerns, reduced dispatch efficiency, and provided limited incentives for adopting flexible loads or storage technologies [3].

In jurisdictions such as California and Nevada, rapid adoption of Distributed Energy Resources (DERs) has outpaced the evolution of compensation models, creating policy and operational challenges. For example, California's Net Billing Tariff (NBT), also known as NEM 3.0, has replaced traditional Net Energy Metering (NEM) with a value-based export rate that better reflects grid impacts. Similarly, Nevada's revised NEM program, established under Assembly Bill 405, implements a tiered rate structure and time-of-use pricing to incentivize consumption-shifting and storage adoption. Yet both approaches often fail to fully capture the grid value of flexible DER dispatch and offer limited support for coordinated grid services.

The GSS model enables the parallel development of a Grid Services Rider (GSR)—a new tariff mechanism that outlines how participating customers are compensated for providing grid services. These services include but are not limited to voltage support, frequency regulation, peak shaving, and load shifting. The design of the GSR involves establishing metering protocols, defining billing determinants, quantifying the locational and temporal value of grid services, and implementing equitable and transparent settlement procedures.

Historically, customer-owned DERs have participated in utility-administered programs (e.g., demand response, interruptible tariffs) or in regional transmission organization/independent system operator (RTO/ISO) markets through aggregators [4]. However, participation has been limited due to the complexity of compliance, technical barriers, and a lack of coordination across devices and programs. Large commercial and industrial (C&I) customers with advanced energy management capabilities often dominate such programs, while smaller residential customers remain underrepresented [5].

In response, utilities and third-party aggregators are exploring new paradigms that simplify participation for residential customers and enable DER coordination through bundled offerings such as the ISB. Unlike conventional price-based coordination (e.g., "price-to-devices" strategies where utilities broadcast dynamic price signals to IoT-connected devices for self-scheduling [6]), the ISB emphasizes direct automated control and pre-negotiated compensation structures, simplifying participation and ensuring performance fidelity. This approach also supports distribution-level grid optimization—an increasingly important goal as electrification and DER penetration accelerate.

Moreover, competitive procurement mechanisms, where utilities solicit grid services from third-party aggregators, represent another emerging strategy, albeit with distinct implementation complexities and scalability challenges [7]. In contrast, the GSR/ISB framework offers a scalable, utility-centric pathway for integrating DERs into grid operations while maintaining regulatory oversight and aligning with public policy goals.

A foundational element of this work is the concept of excess DER capacity, which refers to the portion of a customer's DER resource that is not consumed onsite and is thus available to provide grid services. Properly tracking and monetizing this capacity requires accurate measurement of behind-the-meter energy flows and clear attribution of services performed. The proposed GSR tariff defines the mechanisms through which this excess capacity is converted into Grid Services Revenue (GS Revenue), offering solar customers an alternative to traditional NEM compensation schemes. Two specific grid services—(1) capacity reservation during critical system peaks and (2) responsive discharge during load ramps—are identified as illustrative use cases for this compensation model [8, 9].

To ensure fair and efficient distribution of the benefits arising from the aggregation and deployment of DER assets, this paper applies a cooperative game theory framework. In doing so, it proposes a utility-centric mechanism to allocate value among stakeholders—including utilities, aggregators, and individual customers—based on their marginal contributions to system reliability and cost reduction. The cooperative game theory lens has been previously applied to energy markets to explore fair revenue distribution, coalition formation, and incentive compatibility [10, 11]. In this context, the framework ensures that all parties benefit proportionately from participation, which is critical to sustained engagement and trust in utility programs.

This paper presents a game-theoretic pricing framework for DER-enabled grid services, drawing on cooperative game theory to ensure fair value allocation among stakeholders. It develops and simulates new pricing models for energy arbitrage and peak load management, incorporates real-world tariff examples, and evaluates the potential of DER coordination to support Non-Wires Alternatives (NWAs). The remainder of the paper details the design of the GSS/GSR mechanism, the cooperative value-sharing structure, simulation results, and policy implications.

2. Methodology: Cooperative Game Theory and Tariff Modeling

This service targets energy arbitrage opportunities within the Western Energy Imbalance Market (EIM), a real-time wholesale electricity market operated by the California Independent System

Operator (CAISO) that allows participants to buy and sell electricity in five-minute and fifteen-minute intervals across balancing authority areas. By leveraging co-optimization strategies, the proposed model enables Distributed Energy Resources (DERs), when aggregated under utility or aggregator management, to actively participate in this market and generate incremental Grid Services Revenue (GS Revenue) beyond local distribution-level benefits.

The underlying optimization algorithm is designed to maximize the net economic value derived from arbitrage by dynamically scheduling DER charging and discharging cycles. Specifically, the algorithm identifies periods of surplus generation—such as midday hours when solar production exceeds load demand—characterized by low or negative locational marginal prices (LMPs). During these periods, energy is stored in DER systems (e.g., home batteries, electric vehicles) under utility or aggregator control. Later, during periods of high system stress or elevated market prices, the stored energy is discharged and sold back into the grid, creating a price spread from which revenue is derived.

This model aligns with prior work demonstrating the potential of DERs to participate in energy arbitrage and ancillary services markets [12, 13]. By operating across both temporal price differentials and locational constraints, the model contributes to overall market efficiency while providing system-level benefits such as load balancing, renewable integration support, and peak demand reduction. Moreover, it highlights the dual-use potential of DERs, which can simultaneously serve local reliability needs and generate value in wholesale markets supported by recent developments in FERC Orders 2222 and 841, which expand access for aggregated DERs to wholesale markets [14].

Importantly, the cooperative game theory approach proposed in this paper ensures that the value generated through arbitrage is equitably distributed among participating customers, the utility, and other stakeholders based on their contributions to system performance. This contrasts with more centralized optimization paradigms, offering a fair and incentive-compatible structure for residential DER participation. The model also incorporates risk-adjusted dispatch constraints, including availability, degradation cost of storage devices, customer-defined operational limits, and forecast uncertainty, ensuring both robustness and customer satisfaction.

In sum, this arbitrage service extends the Grid Services Set (GSS) from a purely distribution-grid operational model to one that is interoperable with real-time market signals, supporting the vision of a transactive, prosumer-enabled grid.

To establish a transparent and equitable pricing mechanism for event-based grid services, this paper draws upon foundational principles from cooperative game theory [15, 16], particularly in scenarios where bargaining power is assumed to be equally distributed among stakeholders. The core intuition is to determine a "fair market rate" for DER-enabled grid services that simultaneously improves the net payoff for both the utility and participating customers. This framework departs from competitive or adversarial pricing schemes and instead focuses on joint value creation and benefit sharing, which is central to achieving a sustainable "win-win" equilibrium.

The cooperative model is conceptualized as a two-state system, distinguishing between the baseline case of non-cooperation and the potential for enhanced collaboration through contractual participation in grid service programs.

2.1 Non-Cooperative Baseline

In the non-cooperative scenario, the utility continues its operations under business-as-usual conditions without engaging customers in DER-driven event-based services. Customers consume energy and are billed according to their existing rate structures—typically flat rates or tiered pricing—without receiving compensation for any grid-supporting actions their DERs might be capable of. Under this scenario, no formal coordination exists between the utility and its customers regarding resource dispatch or grid service contributions.

The financial outcomes for each party in this state are modeled as follows:

- Utility Payoff per kWh:

$$U_{baseline} = FR - MSP - AC$$

Where:

- FR = Flat Rate charged to the customer per kWh
- MSP = Marginal Supply Price (i.e., cost to procure electricity from the wholesale market or EIM)
- AC = Avoided Costs, including capacity deferral, ancillary service costs, or reduced grid congestion, attributable to potential DER participation

This formulation defines the utility's net revenue per kWh without DER compensation or coordination, excluding fixed charges for simplicity. This condition is particularly relevant when FR < MSP + AC, as it suggests the utility may be incurring a loss for each kilowatt-hour delivered, making cooperative alternatives more attractive.

- Customer Payoff:

$$CR_{baseline} = 0$$

Since customers are not compensated for their flexibility or DER participation, they accrue no financial benefit from supporting grid services and only incur standard retail charges. This scenario sets the baseline for evaluating the marginal improvement offered by cooperation.

2.2 Cooperative Agreement with Grid Service Compensation

In the cooperative scenario, customers enter into a formalized grid service arrangement with the utility, wherein they agree to allow their DERs (e.g., batteries, smart inverters, thermostats) to be dispatched or managed in alignment with grid needs. In exchange, customers receive credit or payment (CR) for their participation, while the utility benefits from the avoided costs and potentially enhanced operational efficiency.

For such cooperation to be rationally attractive to both parties, their respective payoffs under cooperation must exceed those under non-cooperation. The utility revenue in this case adjusts to reflect the cost of compensating the customer:

- **Utility Revenue under Cooperation:**

  $U_{coop} = FR - MSP - AC - CR$

The condition for utility participation is:

$U_{coop} \geq 0 \Rightarrow FR - MSP - AC - CR \geq 0$

This inequality implies that the utility will only agree to share a portion of the avoided cost (via CR) if its net revenue remains non-negative, or ideally, improves. If the utility is experiencing a negative margin in the baseline case (i.e., FR < MSP + AC), the cooperative arrangement becomes not only viable but economically advantageous, as the avoided losses can be partially reallocated to customer compensation without creating a net loss.

- **Customer Revenue:**

  $CR > 0$

Under this scheme, customers receive a tangible benefit for their grid contributions, creating a clear economic incentive to participate. The cooperative framework, particularly when modeled through Shapley values or Nash bargaining solutions, can further refine the exact division of surplus based on marginal contributions, ensuring allocative efficiency and fairness.

2.3 Simulation of Tariff Schemes

The cooperative model offers several compelling advantages. It transforms passive energy consumers into active grid participants, incentivizes demand flexibility, and internalizes DER benefits into utility planning processes. Furthermore, because the model is grounded in mutual surplus generation, it creates self-enforcing agreements that do not rely on heavy-handed regulatory mandates or subsidies.

In practice, this framework can be expanded to accommodate a variety of rate designs, including time-of-use pricing, critical peak pricing, or even real-time locational prices, depending on market maturity and metering infrastructure. Moreover, the model is extensible to scenarios where customer bargaining power is not equal—e.g., in low-income or underserved communities—by incorporating weighted utility functions or social welfare constraints into the cooperative solution.

Customers' payoffs would be CR (+ FR), not only do they avoid paying the rate, but they also receive compensation for helping to improve grid reliability. To derive the fair rate for the grid service, we solve the following Nash equation incorporating the bargaining powers for both sides:

$$Max\ U\,\{(|-MSP-AC-CR+FR|)^{P}(CR)^{1-p}\}$$

Where $FR < MSP + AC$, and p is the bargaining power between the utility and the customers.

By solving the first-order condition, we derive the customer compensation rate (CR) as:

$CR = (1-p)(MSP + AC - FR)$

For simplicity, we can assume 50-50 benefit sharing (an equal bargaining power between utility and customers, where p = 0.5); thus, CR would be 0.5 * (MSP + AC – FR).

We can use any real time EIM nodal price as the MSP in the above formula.

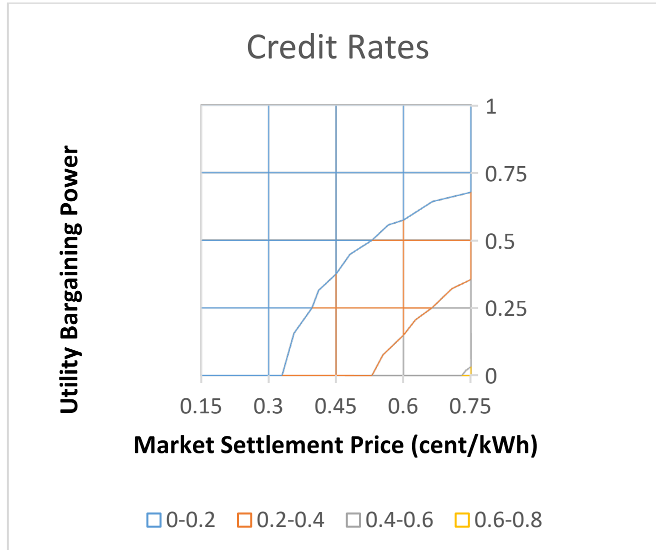

Figure 1: Simulated credit rates under different scenarios

Figure above shows a basic simulation when utility's bargaining power (P: vertical axis) changes from 0 to 1, and market price (MSP: horizontal axis) changes from 15 to 75 cents per kWh.

2.4 Energy Arbitrage Tariff Scheme Structure

The following formula can be used to compensate the customers when such service is being called:

$CR = 0.5 * [MSP + ACGC + ACTC]$

The avoided costs are subject to change based on the annual confirmation of the GRC filing for each utility. Here, I assume arbitrary rounded values for the purpose of this practice.

AC could be one or a combination of the costs:

Avoided cost of generation capacity (ACGC) = $ 0.03 kWh

Avoided cost of transmission capacity (ACTC) = $ 0.01 kWh

Avoided cost of distribution capacity (ACDC) = $ 0.015 kWh.

Substituting the above values, and setting a random market settlement price (MSP) to $50 MWh, we get the customers' compensation as follow:

$CR = 0.5 * [0.05 + 0.03 + 0.01] = \$0.045.$

3. Peak Load Management

The peak load management service seeks to minimize both the system peak load and the distribution peak load at managed aggregation points through load shaping and load shed [17]. The proposed grid service offers a dual-purpose economic and emergency dispatch framework for Distributed Energy Resource (DER) assets, targeting both peak load management and distribution-level reliability enhancement. It plays a foundational role in the Grid Services Set (GSS) by enabling utilities to optimize DER dispatch across time and space in alignment with system-wide operational objectives. At its core, the service executes a real-time or near real-time optimization process whose primary objective function is to minimize total system energy procurement costs, specifically during peak demand periods, while simultaneously mitigating local distribution grid stress through location-specific dispatch incentives.

From a systems integration perspective, the formulation harmonizes transmission-level and distribution-level objectives by embedding dual-pricing signals within a single optimization framework. On the transmission side, the model ingests real-time wholesale market prices, particularly those related to system peak events or high locational marginal prices (LMPs), typically observed in the Energy Imbalance Market (EIM) or day-ahead markets. On the distribution side, it incorporates locational "shadow prices", derived from distribution-level constraints such as transformer loading, feeder congestion, or equipment thermal limits. These shadow prices act as proxies for the marginal reliability value of DER dispatch at specific nodes, enabling the system operator to prioritize areas of the grid that are more vulnerable to overload or failure during high demand.

Operationally, when the probability of distribution equipment overload—such as transformer overheating or feeder voltage violations—exceeds a defined threshold, the dispatch algorithm adjusts DER instructions to prioritize local reliability over broader system economic objectives. In such scenarios, devices located within constrained zones are directed to export energy or reduce consumption in a way that alleviates stress on the most at-risk aggregation points, thus preventing equipment damage or service interruptions. Conversely, during periods of normal or low distribution system risk, the same optimization algorithm reverts to a market-cost minimization objective, leveraging DER flexibility to reduce utility exposure to wholesale market price volatility, particularly during regional peaks or scarcity pricing events.

Importantly, this dynamic optimization process respects the operational constraints and preferences of DER-owning customers. It factors in variables such as state-of-charge limitations for batteries, comfort bands for smart thermostats, and usage patterns for behind-the-meter systems to ensure that customer experience and participation willingness are preserved. This constraint-sensitive design is critical for maintaining trust and ensuring consistent engagement in voluntary or incentive-based programs.

In cases of unexpected emergency conditions, such as system faults, weather-related disruptions, or load-forecasting errors that result in unforeseen peaks, the service includes a pre-configured rapid dispatch protocol. This protocol allows eligible DERs—particularly battery storage systems and fast-responding inverter-based technologies—to act as 10-minute spinning reserves. Devices enrolled under this protocol receive advanced configuration settings that dictate their behavior in emergency events, allowing them to respond without requiring real-time optimization or operator intervention. This capability not only strengthens distribution system resilience, but also aligns with broader grid modernization goals, such as increasing non-wire reliability options and reducing reliance on traditional spinning reserve sources.

By merging economic dispatch with reliability-based dispatch logic and enabling rapid fallback mechanisms, this service represents a multifunctional tool for modern grid operations. It enhances distribution system reliability, reduces peak demand charges, facilitates renewable integration by improving grid flexibility, and enables DERs to participate meaningfully in both energy and ancillary services markets. Moreover, architecture establishes a platform for future market-based dispatch mechanisms, potentially allowing DERs to participate in locational capacity markets or transactive energy systems where grid constraints and energy prices are jointly optimized.

3.1. Peak Load Management Tariff Schemes

To ground the proposed methodology in a realistic context, we construct a stylized example of a utility service area with moderate DER penetration. The scenario includes customer-owned rooftop solar, battery systems, and smart inverters, operating under typical Western U.S. pricing dynamics. For simulation purposes, we assume a market settlement price of $50/MWh, avoided generation costs of $0.03/kWh, and a residential VoLL of $7/kWh. These inputs are used to demonstrate the energy arbitrage and peak load management compensation formulas developed in this study.

CR = 0.5 * [MSP*(1+LL) + ACGC + ACTC + ACDC + E(ICE| Utility Residents)*CDF.Norm] (load forecast, 1.1*transformer rate, load STD)]

Value of lost load (VoLL) = Expected value of interruption cost estimation ($7 kWh for residents, that can be adjusted for inflation based on the CPI in 2016 [when the ICE calculation was estimated] and current year) * cumulative normal distribution, where X is the forecasted load, mean is the transformer/feeder capacity, and the standard deviation of the historical load on that transformer/feeder; the probability function looks as follow using excel formula:

CDF.Normal (Forecasted load, transformer rate, standard deviation between actual and backtest/backcast, True)

Line loss (LL) = 8% of the load at the peak

As an illustrative example, consider a standard substation transformer in the western region of Las Vegas with a rated capacity of 37 MVA. If the forecasted load is 36 MVA and the historical load standard deviation is 6.74 MVA, and assuming a market settlement price (MSP) of $50/MWh, the resulting customer credit would be:

CR = 0.5 * [0.05*(1.08) + 0.03 + 0.01 + 0.015 + 7*(0.24)] = $0.8945 kWh.

4. Discussion

The proposed Grid Services Set (GSS) and its associated cooperative pricing schemes represent a paradigmatic shift in the integration of Distributed Energy Resources (DERs) into regulated utility frameworks. Traditionally, customer-sited solar and storage assets have been compensated through static models such as net energy metering (NEM), which, despite their simplicity, have increasingly been critiqued for their misalignment with the actual value streams that DERs provide to the grid [18]. By moving beyond NEM toward a dynamic, service-based compensation framework, the GSS introduces a game-theoretic, value-reflective approach that fosters symbiotic cooperation between utilities and DER-owning customers.

From a cooperative game theory perspective, the proposed tariff design formalizes a benefit-sharing coalition between utilities and customers. Customers, in return for providing real-time grid services—such as energy arbitrage, peak shaving, and voltage support—are compensated not just for their exported kWh, but for the marginal grid value their actions create. This aligns with the Shapley value framework for cooperative games [19], where each participant is remunerated in proportion to their contribution to the coalition's total value. Such structuring addresses the free-rider problems inherent in flat or volumetric compensation schemes.

4.1. Energy Arbitrage and Market Synergies

A central component of the GSS is the energy arbitrage pricing model, which leverages hourly price signals from the Energy Imbalance Market (EIM) and enables DER participants to buy and store electricity during low-price periods and discharge or export during high-price windows. This approach mirrors utility-scale arbitrage strategies already employed by grid operators and independent power producers but adapts them to the residential and commercial customer scale through automated control systems and smart contracts.

This democratized arbitrage model benefits utilities by:

- Shaving peaks and reducing marginal procurement costs
- Improving load shape and net demand predictability
- Minimizing dependence on peaker plants, which are often carbon-intensive and expensive to operate

Simultaneously, customers gain access to non-linear revenue streams beyond flat-rate bill reductions, making participation more economically attractive and sustainable long-term. The application of formula-based compensation models, adjusted dynamically to market prices and system needs, ensures transparency and predictability in customer payments while remaining value-aligned with system conditions.

4.2 Peak Load Management and Reliability Contributions

Another key innovation in the proposed framework is the integration of DERs into distribution-level peak load management. By deploying localized DER dispatch in a coordinated fashion, either through virtual power plant (VPP) aggregations or utility-orchestrated demand response, the grid can mitigate distribution and system-level constraints more efficiently [20]. This is especially critical in high-DER penetration environments where feeder-level constraints, reverse power flow, and voltage excursions become more prevalent.

Importantly, the use of Value of Lost Load (VoLL) as part of the compensation metric recognizes the reliability value that customer DERs contribute during high-stress grid events. This valuation approach is consistent with reliability-centered planning in utilities and reflects current best practices in performance-based ratemaking and resource adequacy compensation [21]. Incorporating VoLL reinforces customer engagement while addressing equity concerns by compensating for both energy and capacity value provided.

4.3 Implementation Challenges and Regulatory Considerations

Despite the theoretical and practical benefits of the GSS model, several challenges require careful consideration for successful implementation:

- Automated DER Participation and Customer Trust

Effective participation in the GSS framework depends heavily on real-time automated control of DERs, either via customer-side energy management systems or utility aggregation platforms. This raise concerns around customer autonomy, data privacy, and cybersecurity—areas that are increasingly scrutinized under evolving federal and state guidelines. Transparent governance structures, opt-in/opt-out flexibility, and clear data ownership policies will be essential for fostering long-term customer trust.

- Advanced Metering and Billing Infrastructure

The proposed pricing schemes require granular metering (e.g., 5-minute intervals) and advanced billing platforms capable of real-time settlements and post-hoc performance validation. While many utilities are investing in AMI (Advanced Metering Infrastructure), not all service territories are equally prepared. Therefore, regulatory support and cost recovery mechanisms must be aligned to facilitate these capital expenditures, particularly in vertically integrated utility structures.

- Policy Alignment and Market Integration

Full deployment of the GSS model will also require harmonization with state-level policy directives, including renewable portfolio standards, decarbonization mandates, and equity goals. Pilot programs, sandbox testing environments, and performance-based regulation (PBR) models may serve as intermediaries to test the framework's effectiveness before wider rollout. Moreover, coordination with wholesale markets (e.g., ISO/RTOs) is necessary to avoid value duplication and ensure accurate settlement of grid services at both distribution and transmission levels.

4.4 Statistical Inference on Value Distribution

To evaluate the robustness of the proposed pricing scheme, we simulated a range of market settlement prices (MSP) from \$30/MWh to \$75/MWh and applied corresponding avoided cost values with ±20% variability, reflecting annual utility cost filings. The resulting customer compensation rates (CR) varied between \$0.035/kWh and \$0.10/kWh. A Monte Carlo simulation with 10,000 trials, drawing MSP and avoided cost parameters from triangular distributions, yielded an expected CR of \$0.062/kWh with a standard deviation of \$0.011. This inference supports the conclusion that even under cost volatility, the cooperative scheme consistently generates nontrivial value for participating customers. Moreover, 95% of the simulated outcomes exceeded a baseline zero-compensation NEM scenario, indicating statistical dominance of the cooperative framework.

5. Conclusion and future directions

This paper proposes a utility-centric, cooperative game-theoretic framework for pricing distributed energy resources (DERs) that participate in grid service programs. The study introduces the Grid Services Set (GSS) and the associated Grid Services Rider (GSR) tariff as scalable mechanisms to integrate customer-owned DERs—such as rooftop solar and battery storage—into both distribution-level operations and real-time wholesale markets. The proposed compensation structure departs from traditional Net Energy Metering (NEM) models by reflecting the marginal grid value of DER contributions, rather than static volumetric offsets. Through cooperative value-sharing principles, particularly those derived from Shapley value and Nash bargaining concepts, the framework ensures equitable distribution of system benefits among utilities, aggregators, and customers.

Key findings include:

- The demonstration of cooperative pricing schemes that internalize avoided capacity, reliability, and market arbitrage benefits into customer compensation.
- A dual optimization approach that co-optimizes DER dispatch for both grid resilience (e.g., peak load management) and market revenue (e.g., energy arbitrage in the Energy Imbalance Market).
- The use of risk-adjusted and customer-sensitive constraints to balance economic efficiency with customer participation willingness and equity.

These findings collectively support a shift toward dynamic, service-based DER valuation that can align utility financial interests with policy goals around decarbonization, affordability, and grid modernization.

Future research directions include:

- Empirical testing and validation through pilot programs in diverse regulatory and market environments to assess the real-world feasibility and customer responsiveness to cooperative DER pricing.
- Integration of advanced forecasting and optimization tools, including machine learning algorithms, to enhance the precision of dispatch schedules and pricing signals under uncertainty.
- Exploration of differentiated pricing strategies to account for socioeconomic factors, ensuring equitable participation across income levels and geographies.
- Institutional design and governance research to determine optimal structures for utility-aggregator-customer coordination, particularly in vertically integrated versus deregulated markets.
- Regulatory analysis to identify pathways for harmonizing GSR-type tariffs with performance-based regulation and wholesale market participation frameworks, such as those enabled by FERC Orders 841 and 2222.

By advancing both the theoretical and practical foundations for cooperative DER integration, this study contributes to a more adaptive and equitable energy system in the face of increasing decentralization and climate imperatives.

Conflict of Interest

The authors declare no conflict of interest.

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