Distribution System Congestion Management Under Various Utility-Aggregator Coordination Architectures

Prudhviraj Dhanapala, *Student Member, IEEE*, Kiran Kumar Challa, *Senior Member, IEEE*, Kumarsinh Jhala, *Senior Member, IEEE.*, and Balasubramaniam Natarajan, *Senior Member, IEEE.*

***Abstract*—The increasing proliferation of distributed generation (DG) and flexible resources in distribution systems has introduced new operational challenges, particularly in managing network congestion and ensuring coordinated interactions between transmission and distribution system operators. This article investigates coordinated operational planning frameworks for congestion management in active distribution networks with high DG penetration. To this end, we develop and analyze two representative distribution system operator (DSO) architectures, the Minimal DSO and the Total DSO, designed to operate within the day-ahead market framework. The proposed architectures differ in their levels of coordination, communication, and control between the Transmission System Operator (TSO), the DSO, and DG aggregators. The Minimal DSO adopts a sequential, validation and mitigation approach for market-cleared DG schedules, whereas the Total DSO performs an integrated optimization that jointly maximizes market revenues and enforces network constraints. A comparative analysis is performed to assess the operational and economic performance of both architectures in terms of congestion mitigation, DG utilization, and system reliability. The developed models are implemented and validated on the IEEE 123-bus test system, incorporating realistic DG profiles and day-ahead market scenarios. The results demonstrate that while both architectures ensure reliable network operation, the Total DSO framework achieves higher DG utilization under network constraints, highlighting its potential as an enabling structure for future active distribution networks. However, this comes at the cost of increased DSO responsibility, data/communication requirements, and computational complexity to support integrated operational planning.**

***Index Terms*—Distribution system operator, TSO-DSO coordination, congestion management, optimal power flow, aggregation**

I. Introduction

Power distribution system is witnessing rapid proliferation of behind-the-meter (BTM) flexible loads, distributed generations (DGs), battery energy storage systems, and demand response resources. These resources, if managed properly, can provide market and grid services to transmission and distribution systems. This transformation is driven by the increasing need for grid flexibility, technological advancements, and evolving regulatory frameworks. In particular, FERC Order No. 2222 [1] allows aggregated resources located in distribution system (DS) with a minimum capacity of 100 kW to participate in wholesale markets [2]. This regulatory development has opened new revenue streams for consumers and aggregators, potentially making energy more affordable. However, while such bulk market participation frameworks enhance system flexibility and efficiency at the transmission level, they may simultaneously introduce operational challenges at the distribution level. One of the most significant challenges is distribution system congestion, which arises from the fact that these resources are dispatched over the DS and causes uncertain bidirectional power flows due to the stochastic nature of DERs. Congestion management for the distribution system involves strategies to balance supply and demand across the network, ensuring that the power flow remains within the physical constraints of the grid.

These operational complexities necessitate new coordination mechanisms between transmission system operators (TSOs), distribution system operators (DSOs), aggregators, and consumers to ensure reliable and efficient operation across grid layers. Consequently, the role of the utilities have become increasingly critical as a network operatorresponsible for congestion management, DER coordination, and seamless TSO–DSO interaction [3]. Effective congestion management in distribution networks requires proactive rather than reactive operational strategies. Day-ahead operational planning plays a pivotal role in anticipating potential network congestion and allocating DERs in a manner that ensures both grid reliability and economic efficiency [4]. Managing network congestion while maximizing aggregator revenues is typically achieved by solving the Optimal Power Flow (OPF) problem, which is inherently challenging due to its nonlinear and nonconvex characteristics [5]. Several approaches, ranging from conventional parametric formulations to modern data-driven methods, have been proposed to address OPF in distribution systems [5]. While OPF itself is a computationally intensive task, incorporating TSO–DSO interactions further increases its complexity. This hierarchical coordination problem is commonly formulated as a bi-level optimization, where the TSO defines a feasible operating region that implicitly constrains the DSO-level OPF. In [6], this complex bi-level problem was addressed using a decomposition-based technique with a convex AC-OPF formulation to guarantee convergence. Similarly, [7], employs the Alternating Direction Method of Multipliers to solve the TSO–DSO coordination problem based on iterative

The submitted manuscript has been created by UChicago Argonne, LLC, Operator of Argonne National Laboratory ("Argonne"). Argonne, a U.S. Department of Energy Office of Science laboratory, is operated under Contract No. DE-AC02-06CH11357. The U.S. Government retains for itself, and others acting on its behalf, a paid-up nonexclusive, irrevocable worldwide license in said article to reproduce, prepare derivative works, distribute copies to the public, and perform publicly and display publicly, by or on behalf of the Government.

979-8-3315-8138-1

information exchange between the two entities. In [8], the bi-level optimization is reformulated as a Mathematical Program with Complementarity Constraints and solved using an interior–exterior penalty approach.

As the penetration of DERs continues to rise, solving this hierarchical coordination problem efficiently has motivated the development of both data-driven [9] and analytical [10] methods for OPF. Within the TSO–DSO coordination context, capturing real and reactive power flexibility while achieving economic objectives is critical. For example, [11] quantifies PQV-based distribution system flexibility using a two-stage sampling strategy combining bounding-box projection and Fibonacci direction techniques to characterize the feasible operating region. Other studies have focused on specific coordination goals: [12] models reactive power capabilities as probabilistic capability charts using probabilistic curve representations, while [13] proposes analytical methods to quantify probabilistic line loading, a key metric in volatile market participation.

However, most existing OPF-based coordination frameworks implicitly assume traditional roles and responsibilities for the TSO and DSO. With the rapid growth of DERs and aggregators, new operational challenges have emerged, necessitating redefinition of the DSO construct. The DSO, conceived not merely as an organizational entity but as a functional and market-oriented framework, represents a paradigm shift toward actively managed distribution networks [14]. Modern DSOs are expected to manage bidirectional power flows, integrate distributed flexibility resources, and operate the transmission–distribution (T–D) interface in near real time. By integrating planning, market, and operational functions, DSOs can unlock the value of flexibility services while deferring costly infrastructure upgrades [15]. Therefore, this work analyzes congestion management under various DSO architectures and evaluates their performance in terms of operational cost and DER utilization. Specifically, we model and assess congestion management in two representative DSO architectures—the Minimal DSO and the Total DSO. The key contributions of this work are as follows:

- Development of a comprehensive DSO–DER coordination and control architecture for congestion management under both the minimal DSO and Total DSO operational paradigms. The proposed framework systematically contrasts limited-control environments with fully coordinated architectures, highlighting the structural and informational requirements needed for effective distribution-level decision making.
- Formulation of an optimization-driven congestion management strategy using an OPF framework tailored to both minimal and Total DSO scenarios. The OPF models explicitly incorporate network constraints, DER capabilities, and voltage-sensitivity information, enabling the DSO to perform informed, system-wide curtailment decisions that balance reliability, operational constraints, and renewable utilization.
- Implementation and validation of the proposed architectures on the IEEE 123-bus test system, demonstrating how each DSO model influences DER dispatch efficiency, voltage regulation effectiveness, and overall curtailment requirements. The results quantify the improved DER utilization and operational performance achievable through enhanced coordination in high-DER-penetration distribution networks.

The remainder of the paper is organized as follow; Section II illustrates the minimal and total DSO frameworks. Section III presents the mathematical modeling of both the DSO models. Section IV discuss the siumulation results and Section V concludes.

II. DSO ARCHITECTURES

The Minimal DSO and Total DSO architectures primarily differ in their levels of coordination, communication, and control among the TSO, the distribution utility, and DERs. These differences determine how economic optimization and network feasibility are integrated within the overall operational framework.

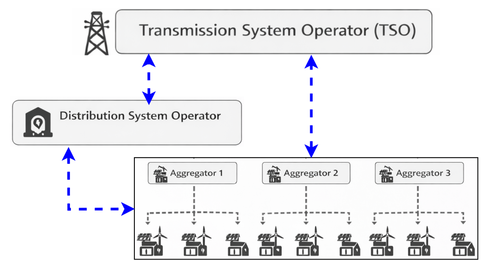

Fig. 1: Minimal DSO Architecture

As shown in 1, the Minimal DSO architecture, communication between the TSO and the DSO/utility is limited and largely unidirectional. The TSO clears the wholesale market based on aggregated DER offers, and the DSO subsequently validates these dispatch results against the physical constraints of the distribution network. Any infeasibilities, such as voltage or thermal limit violations, are handled locally through curtailment or adjustment of DER outputs. Hence, this approach emphasizes simplicity and institutional separation but at the expense of full DER utilization and overall economic efficiency.

Conversely, the Total DSO architecture in 2 features a more advanced coordination mechanism, characterized by bidirectional communication and integrated decision-making between market and network layers. Here, the DSO directly incorporates both economic objectives (such as revenue maximization) and network constraints (such as voltage stability and line

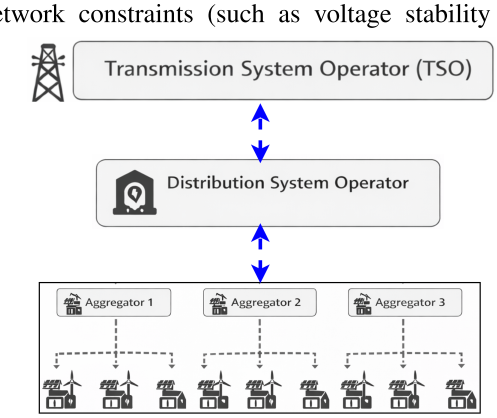

Fig. 2: Total DSO Architecture

979-8-3315-8138-1

loading) into a single optimization framework. This unified control structure enables simultaneous congestion management and optimal DER dispatch, ensuring efficient resource utilization and minimizing post-market interventions.

Despite their structural differences, both architectures share a common goal, to maximize DER participation and economic returns while maintaining secure and reliable network operation. The choice between them depends on the desired level of institutional integration, data exchange, and operational complexity that a utility or regulatory framework can support. In practice, the Minimal DSO represents an incremental step toward active distribution management, while the Total DSO reflects a more comprehensive and future-oriented model aligned with high DER penetration scenarios.

III. Mathematical Modeling

This sections details the optimization formulation for the Minimal and Total DSO architectures. Firstly, various DERs in the system are modeled, later these DER models will be considered as constraints in the OPF formulations. This work considers price response demand response, solar PV, and battery energy storage systems as DERs. The price-responsive demand response loads are modeled as;

$$p^{dr}_{i,\phi} = P^{dr}_{i,\phi} \qquad \text{if } \rho_t \leqslant \rho_{b_1} \tag{1}$$

$$p^{dr}_{i,\phi} = \epsilon^1_{i,\phi} P^{dr}_{i,\phi} \quad \text{if } \rho_{b_1} \leqslant \rho_t \leqslant \rho_{b_2} \tag{2}$$

$$p^{dr}_{i,\phi} = \epsilon^2_{i,\phi} P^{dr}_{i,\phi} \qquad \text{if } \rho_t \geqslant \rho_{b_2} \tag{3}$$

where $P^{dr}_{i,\phi}$ and $p^{dr}_{i,\phi}$ are the demand response load dispatches and flexible load availability at i^{th} node of ϕ^{th} phase. $\epsilon^1_{i,\phi}$ and $\epsilon^2_{i,\phi}$ are the fraction of flexible demand response load possible through the day-ahead optimization. ρ_{b_1} and ρ_{b_2} price bands. Model for the solar PVs with the respective constraints is;

$$0 \leqslant p^s_{i,\phi} \leqslant P^s_{i,\phi} \tag{4}$$

where $p^s_{i,\phi}$ and $P^s_{i,\phi}$ are the possible solar PV dispatch and available capacity of generation at i^{th} node of ϕ^{th} phase. The BESS capacity and charge/discharge constraints are;

$$p^{\text{b}}_{i,\phi} = p^{\text{dis}}_{i,\phi} - p^{\text{cha}}_{i,\phi} \tag{5}$$

$$p^{\text{cha}}_{i,\phi} \leqslant \beta_{i,\phi} P^{\text{cha}}_{i,\phi} \tag{6}$$

$$p^{\text{dis}}_{i,\phi} \leqslant (1-\beta_{i,\phi}) P^{\text{dis}}_{i,\phi} \tag{7}$$

$$SoC_{i,\phi} = SoC^{init}_{i,\phi} + \left(\eta^{\text{cha}} p^{\text{cha}}_{i,\phi} - \frac{p^{\text{dis}}_{i,\phi}}{\eta^{\text{dis}}}\right) \tag{8}$$

$$SoC^{\text{min}}_{i,\phi} \leqslant SoC_{i,\phi} \leqslant SoC^{\text{max}}_{i,\phi} \tag{9}$$

$$\beta_{i,\phi} \in [0,1] \tag{10}$$

Here, $p^b_{i,\phi}$ is the BESS dispatch. $p^{dis}_{i,\phi}$ and $p^{cha}_{i,\phi}$ are the charging and discharging schedules; $\beta_{i,\phi}$ is a binary variable decides either to charge or discharge of BESS at i^{th} node of ϕ^{th} phase; $P^{dis}_{i,\phi}$ and $P^{cha}_{i,\phi}$ are the maximum discharging and charging capabilities of respective BESS; following their respective charge discharge efficienciesη^{cha} and η^{dis}; State of charge $SoC_{i,\phi}$ follows the respective $SoC^{min}_{i,\phi}$ and $SoC^{max}_{i,\phi}$ constraints.

OPF Formulation:

$$\underset{P^{DER}}{\text{argmin}} \sum_{i=1}^{N} \sum_{\phi=1}^{\Psi} \Big(\rho(p^g_\phi)\Big) \tag{11}$$

subject to

$$p^g_{i,\phi} + \sum_{i=1}^{N} p^b_{i,\phi} + \sum_{i=1}^{N} p^s_{i,\phi} = \sum_{i=1}^{N} p^l_{i,\phi} + \sum_{i=1}^{N}\sum_{j=1}^{N} p_{i,j,\phi} \quad \forall \quad t \tag{12}$$

$$p^l_{i,\phi} = p^{fix}_{i,\phi} + p^{dr}_{i,\phi} \tag{13}$$

$$p^g_{i,\phi} + p^b_{i,\phi} + p^s_{i,\phi} = p^l_{i,\phi} + \sum_{j=1}^{N} p_{i,j,\phi} \tag{14}$$

$$P_{i,\phi} = V_{i,\phi} \sum_{j=1}^{N} V_{j,\phi} Y_{i,j,\phi} \cos(-\theta_{i,j,\phi} + \delta_{i,\phi} - \delta_{j,\phi}) \tag{15}$$

$$Q_{i,\phi} = V_{i,\phi} \sum_{j=1}^{N} V_{j,\phi} Y_{i,j,\phi} \sin(-\theta_{i,j,\phi} + \delta_{i,\phi} - \delta_{j,\phi}) \tag{16}$$

$$P_{i,\phi} = p^g_{i,\phi} + p^b_{i,\phi} + p^s_{i,\phi} - p^l_{i,\phi} \tag{17}$$

$$p_{i,j,\phi} = V_{i,\phi} V_{j,\phi} Y_{i,j,\phi} \cos(-\theta_{i,j,\phi} + \delta_{i,\phi} - \delta_{j,\phi}) \tag{18}$$

$$V_{min} \leqslant V_{i,\phi} \leqslant V_{max} \tag{19}$$

Here, the objective (10) is to maximize the utility revenue by maximizing the utilization of DERs. ρ is the market price that decides the power derived from the grid $p^g_{i,\phi}$ for all the nodes $i \in N$ and phases $\phi \in \Psi$. $P^{DER} \in p^{dr}, p^b, p^s$ are the DER outcomes. The Constraints (11)-(18) ensure the network constraints, such as power balance, power flows, and voltage limits; $P_{i,\phi}, Q_{i,\phi}$ are the active and reactive power injections at i^{th} node of ϕ^{th} phase. $V_{i,\phi}$ is the voltage magnitude of i^{th} node of ϕ^{th} phase. The above optimization formulation is NP hard, and it is computationally intensive. In this work, the DSO models follow different approaches to solve the OPF based on the architecture limitations

A. *Minimal DSO*

In the Minimal DSO architecture, the distribution utility primarily functions as a network validator, ensuring that the operation of DERs does not compromise local network reliability. In this configuration, DERs or their aggregators directly participate in the wholesale market operated by the TSO/ISO, submitting bids and dispatch quantities based on market clearing results. The DSO subsequently receives the aggregated DER schedules or outputs and validates them against the distribution network constraints, such as voltage limits, thermal ratings, and power flow feasibility.

If the validated dispatch results in network congestion, typically observed as voltage violations or line overloads, the DSO communicates the curtailed DER outputs back to the TSO/ISO. This feedback ensures that system reliability is maintained, albeit at the cost of reduced DER utilization. The congestion mitigation process in this architecture is often governed by rule-based or heuristic curtailment strategies, applied locally by the utility without co-optimization of market and network objectives.

Because the revenue optimization (performed by the market operator) and network validation (performed by the DSO) are decoupled, the overall decision-making process follows a sequential or decoupled OPF framework. While this approach simplifies coordination and preserves the autonomy of both entities, it leads to suboptimal economic outcomes and under-utilization of DER flexibility. As a result, the Minimal DSO architecture represents a pragmatic but limited coordination model, suitable for systems with moderate DER penetration where real-time congestion is infrequent. However, as DER proliferation increases, its limitations in achieving system-

979-8-3315-8138-1

wide efficiency and flexibility utilization become more pronounced.

B. Total DSO

In the Total DSO architecture, the distribution utility assumes an integrated operational and market coordination role, performing both revenue maximization and network validation within a unified optimization framework. Unlike the Minimal DSO, where economic and physical feasibility analyses are performed sequentially and independently, the Total DSO model formulates a co-optimized problem that simultaneously considers market clearing objectives and distribution network constraints. This integrated approach ensures that DER dispatch decisions are both economically optimal and electrically feasible, thereby eliminating the need for post-market curtailment or rule-based adjustments.

By jointly optimizing DER participation and network operation, the Total DSO architecture enables efficient utilization of distributed flexibility resources, including generation, storage, and demand response. This results in improved system-wide efficiency, reduced congestion, and enhanced reliability across the distribution network. Moreover, since the DSO manages both the technical and economic dimensions of DER coordination, it can implement fair and transparent allocation mechanisms, ensuring equal opportunity for all participating DERs. Such mechanisms promote equitable access to market revenues while maintaining adherence to local operational limits.

Additionally, the Total DSO model enhances the coordination between transmission and distribution systems by providing aggregated, network-aware flexibility offers to the TSO/ISO. This facilitates a more accurate representation of the distribution network's operational capabilities in the wholesale market. Through this holistic framework, the Total DSO architecture not only improves DER owners' satisfaction and market participation equity, but also contributes to the broader objectives of system reliability, economic efficiency, and sustainable grid operation.

IV. Test System and Results

The proposed DSO–DER coordination architectures are evaluated on the IEEE 123-bus test system for both the minimal DSO and Total DSO configurations. In the minimal DSO architecture, operational limitations restrict the controller's ability to perform location-specific actions; consequently, the utility relies on a uniform DER-curtailment scheme to preserve network reliability under varying DER operating conditions. Under normal, uncongested conditions, no DER curtailment is necessary. A congested operating scenario is identified by simulating the system over a range of day-ahead loading conditions and DER dispatch levels. During peak DER production, particularly around 2 PM in the day-ahead schedule, nodal voltages exceed the acceptable operating band of 0.95–1.05 p.u. Although some utilities permit a wider voltage margin (0.9–1.1 p.u.), the simulation results demonstrate that under high DER penetration, node voltages can surpass even the 1.1 p.u. upper bound, as illustrated in Fig. 3. This highlights the increasing need for coordinated DER management in distribution networks with high renewable adoption.

In the minimal DSO architecture, acceptable voltage levels are traditionally restored by uniformly curtailing DER outputs across the network. However, when the spatial distribution of DERs is known, voltage-sensitivity information can be leveraged to identify the most influential DER locations for targeted curtailment. The latter strategy is adopted in this work to avoid overly conservative system-wide DER reductions. Using the voltage-sensitivity–based approach, nodal voltage magnitudes are brought back to within the acceptable range ($\leqslant$ 1.05 p.u.) by proportionally reducing DER outputs at nodes exhibiting higher voltage impacts. The resulting nodal voltages and DER curtailment profiles are illustrated in Fig. 3. As shown, DERs located near nodes with voltages exceeding 1.05 p.u. experience greater curtailment, while DERs at non-critical nodes remain largely unaffected. Following the targeted curtailment, all nodal voltages are successfully regulated to $\leqslant$ 1.05 p.u., confirming the effectiveness of the proposed approach.

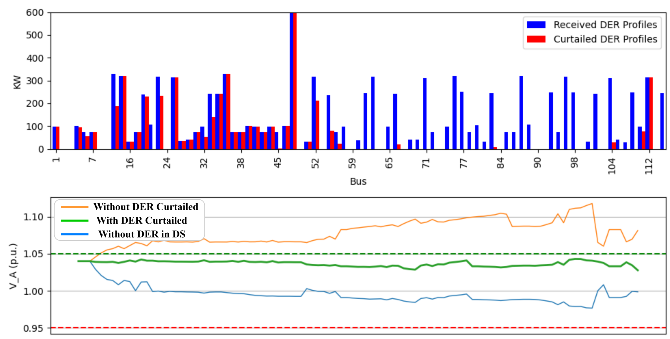

Fig. 3: Generator power and nodal voltages for Minimal DSO

In the total DSO architecture, the utility solves the optimal power flows (OPF) to maximize DER utilization and revenue. OPF for total DSO the proposed studies is formulated using current-voltage (IV) formulation, which enables a robust representation of voltage and current variables suitable for unbalanced distribution networks. The OPF is implemented using the PowerModelsDistribution package, an open-source Julia-based framework for scalable distribution-system optimization [16]. The proposed modeling framework enables flexible experimentation with various DSO architectures and DER coordination strategies within unbalanced distribution networks. In the Total DSO architecture, the operator leverages detailed network information, DER capacities, and voltage-sensitivity relationships to maintain nodal voltages within the acceptable operating band of 0.95–1.05 p.u. while minimizing total DER curtailment. This enhanced flexibility allows the DSO to distribute the required curtailment optimally across multiple DERs, thereby reducing the overall curtailment burden compared to rigid or location-specific methods. Unlike the minimal DSO architecture—where curtailment is applied only to DERs located at nodes exhibiting overvoltage conditions—the Total DSO strategy coordinates DER outputs system-wide to achieve voltage regulation with significantly lower aggregate curtailment. As a result, the system attains improved voltage compliance and higher renewable utilization.

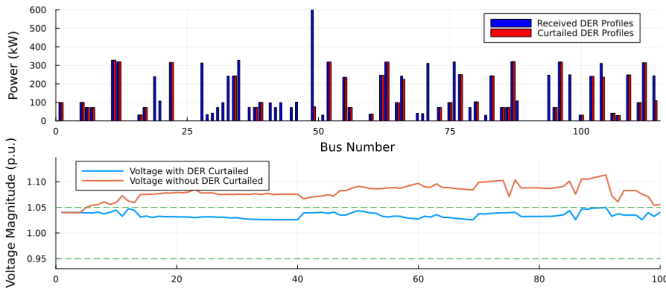

Fig. 4: Generator power and nodal voltages for Total DSO

A comparison of the total DG real-power output and the corresponding curtailment percentages for both architectures is provided in Table I. Prior to any congestion management, the aggregate available DG capacity in the system is 10,749 kW. After applying the respective congestion-management strategies, the minimal DSO architecture yields a total DG output of 4,625 kW, whereas the Total DSO architecture delivers a substantially higher output of 6,425 kW. These results clearly demonstrate the advantages of the increased operational flexibility offered by the Total DSO approach. Specifically, by coordinating curtailment decisions across the entire network, rather than targeting only DGs located at overvoltage nodes, the Total DSO achieves nearly double the usable DG real-power contribution compared to the minimal DSO. This improvement reflects a more efficient utilization of DGs and highlights the importance of system-wide optimization in high-DG-penetrated distribution networks.

TABLE I: Comparison of Min DSO and Total DSO

	Total P	**% Curtailment**
Min DSO	4,625.08	56.97
Total DSO	6,425	39.68

These results demonstrate that the enhanced flexibility of the Total DSO architecture enables significantly more efficient DER coordination compared to the minimal DSO approach. By leveraging detailed network models, voltage sensitivities, and system-wide optimization, the Total DSO maintains all nodal voltages within acceptable limits while minimizing overall curtailment. Consequently, the usable DER real-power output nearly doubles relative to the minimal DSO, highlighting the critical value of coordinated, distribution-level optimization in high-DER environments.

V. Conclusion

This work develops a coordinated DSO–DER control architecture for congestion management under both minimal and Total DSO frameworks. An OPF-based congestion management formulation is proposed, incorporating network constraints, DER capabilities, and voltage sensitivities to guide optimal curtailment decisions. In the minimal DSO architecture, utilities preserve network reliability by applying rule-based curtailment to DERs after the economic optimization step, often resulting in conservative operation and reduced DER participation. In contrast, the Total DSO architecture enforces reliability through a fully integrated techno-economic optimization, enabling coordinated DER dispatch that simultaneously satisfies system constraints and maximizes economic value. The proposed architectures are implemented on the IEEE 123-bus system, demonstrating how increased coordination significantly improves voltage regulation and DER utilization in high-penetration distribution networks. Future work will extend this framework to a multi-period optimization setting to capture the temporal flexibility of DERs and energy storage systems. Additionally, a detailed phase-level investigation will be conducted to better understand the impacts of three-phase unbalance and further enhance the practical applicability of the proposed coordination architectures.

References

[1] Federal Energy Regulatory Commission, “FERC Order No. 2222: Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs.” FERC Order, Sept. 2020. Accessed: 2024-01-20.

[2] F. E. R. Commission *et al.*, “Participation of distributed energy resource aggregations in markets operated by regional transmission organizations and independent system operators,” *Docket No. RM18-9-000*, pp. 2020–09, 2020.

[3] P. De Martini, L. Kristov, and L. Schwartz, “Distribution systems in a high distributed energy resources future: planning, market design, operation and oversight,” *Future Electric Utility Regulation series. Lawrence Berkeley National Laboratory*, 2015.

[4] D. Prudhviraj, P. B. S. Kiran, and N. M. Pindoriya, “Day-ahead energy management of a microgrid with battery energy storage integration,” in *2018 IEEE Innovative Smart Grid Technologies - Asia (ISGT Asia)*, pp. 822–827, 2018.

[5] A. Babiker, S. S. Ahmad, I. Ahmed, M. Khalid, M. A. Abido, and F. S. Al-Ismail, “Optimal power flow: A review of state-of-the-art techniques and future perspectives,” *IEEE Access*, 2025.

[6] Z. Yuan and M. R. Hesamzadeh, “Hierarchical coordination of tso-dso economic dispatch considering large-scale integration of distributed energy resources,” *Applied energy*, vol. 195, pp. 600–615, 2017.

[7] L. Marques, A. Sanjab, Y. Mou, H. Le Cadre, and K. Kessels, “Grid impact aware tso-dso market models for flexibility procurement: Coordination, pricing efficiency, and information sharing,” *IEEE Transactions on Power Systems*, vol. 38, no. 2, pp. 1920–1933, 2022.

[8] P. A. Sharma, A. Mohapatra, and A. Sharma, “A novel interior-exterior approach for the tso-dso based bilevel optimal power flow,” *IEEE Transactions on Power Systems*, vol. 39, no. 2, pp. 3471–3484, 2023.

[9] Z. Yan and Y. Xu, “Real-time optimal power flow with linguistic stipulations: Integrating gpt-agent and deep reinforcement learning,” *IEEE Transactions on Power Systems*, vol. 39, no. 2, pp. 4747–4750, 2023.

[10] Y. Che, X. Wang, X. Lv, and Y. Hu, “Probabilistic load flow using improved three point estimate method,” *International Journal of Electrical Power & Energy Systems*, vol. 117, p. 105618, 2020.

[11] B. Dindar, C. B. Saner, H. K. Çakmak, and V. Hagenmeyer, “A tso-dso coordination framework via analytical representation and monetization of pqv-based distribution system flexibility,” *arXiv preprint arXiv:2510.01854*, 2025.

[12] S. Stanković and L. Söder, “Probabilistic reactive power capability charts at dso/tso interface,” *IEEE Transactions on Smart Grid*, vol. 11, no. 5, pp. 3860–3870, 2020.

[13] K. Jhala, Z. Zhou, and J. Kwon, “Techno-economic analysis on the dual-use of pumped storage hydro as transmission service provider and market participant,” in *2023 IEEE Power & Energy Society General Meeting (PESGM)*, pp. 1–5, IEEE, 2023.

[14] A. Anisie, F. Boshell, and E. Ocenic, “Future role of distribution system operators: Innovation landscape brief,” *The International Renewable Energy Agency (IRENA), Abu Dhabi, United Arab Emirates*, 2019.

[15] B. Uzum, Y. Yoldas, S. Bahceci, and A. Onen, “Comprehensive review of transmission system operators–distribution system operators collaboration for flexible grid operations,” *Electric Power Systems Research*, vol. 227, p. 109976, 2024.

[16] D. M. Fobes, H. Hasanbeig, A. Khodayar, T. Kuruganti, and L. Tesfatsion, “Powermodelsdistribution.jl: An open-source framework for unbalanced distribution network optimization,” *Electric Power Systems Research*, vol. 211, p. 108445, 2022.

979-8-3315-8138-1