Comparing Electricity Market Configurations: Transmission, Distribution, and Peer-to-Peer

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Abstract—The rise of distributed energy resources (DERs) is transforming the electricity network and corresponding markets beyond the traditional wholesale structure. However, there are few published studies that investigate which administrative structure would be most suitable in different contexts. In this paper, the relative costs of various potential electricity market configurations are investigated, including transmission-level wholesale, distribution-level markets, and peer-to-peer transactions in four combinations. The new proposed formulation minimizes total costs, inclusive of energy costs as well as the overhead administrative costs, thereby providing a more complete and holistic comparison of administrative options. Simulation results show that establishing a new market at the distribution level alongside the existing transmission wholesale market yields the highest economic efficiency at a total cost of $1,587,218, whereas relying exclusively on the traditional wholesale market at the transmission level offers the least cost-effective option at a total cost of $4,205,591 for the sample case study. Also, peer-to-peer is economically advantageous in supporting DER integration and reducing the total costs, although it exhibits slightly higher transactional costs than the distribution-level market. This proposed model provides a scientific, non-partisan, unbiased tool for policymakers and decision-makers in designing efficient administrative structures for electricity.

Keywords—electricity market, market structure, peer-to-peer, wholesale

NOMENCLATURE

A. Indices

g, p, m	Buyer index in TSO, DSO, and P2P markets.
n	Seller index in P2P market.

B. Parameters

N	Number of participants.
G, P, Q	Set of TSO, DSO, and P2P market participants.

C. Variables

$\overline{D}, \underline{D}$	Demand upper and lower limits (MW).
D_{mn}^{P2P}	Electricity purchased by node m from node n (MW).
D_{nm}^{P2P}	Electricity sold from node n to node m (MW).
SF_{Grid}	Service fee.
a, b, c, d, e	Electricity price curve parameters.
J	Total transactions ($).
PG	Power generation (MW).
D	Demand (MW).
λ	Electricity price ($/MW).

I. INTRODUCTION

The landscape of electricity markets is evolving rapidly in response to increasing penetration of distributed energy resources (DER), electrification of transport, and changing consumer behaviors [1]. The utilization of DERs, although beneficial for flexibility, congestion-relief, and decarbonization fronts, poses some challenges to the operation of the traditional distribution electricity network, particularly because they cannot participate in the wholesale market, due to their typically small size and weather-dependent intermittent operation [2]. In the U.S., FERC Order 2222 was introduced in 2020 to allow DERs to participate in the wholesale market through aggregators as price-setters; although, there have been a few challenges affecting the DER integration with the wholesale market, such as market eligibility rules by independent system operators and market-clearing complexities [3]. Therefore, there is a compelling need for a new market structure to accommodate such participants and accompany the existing market. There are various electricity market topologies, each with advantages and limitations regarding scalability, integration of DERs and electric vehicles. In general, electricity markets are categorized into three main levels: the wholesale market at the transmission system operators (TSO), the retail market at the distribution system operators (DSO) and local distribution companies (LDCs), and the peer-to-peer (P2P) market at the consumer level for prosumers and local community transactions [4]. The wholesale market is the industry standard for the electricity sale from generation units to large consumers and LDCs, and is overseen in Ontario by the Independent Electricity System Operator (IESO), which safeguards the electricity network reliability [5]. The retail market comprises LDCs that purchase electricity from the wholesale market (and sometimes directly from generation) to resell to smaller consumers [6]. The P2P markets allow direct transactions among prosumers and community-level trading, thereby enabling increased uptake of local renewables and strengthening demand response potentials. However, P2P designs face some drawbacks, including computational complexity, scalability issues, grid-operability constraints, coordination with upstream markets, and sub-optimal system-level operations [7].

Research on market designs for integrating DERs has focused on three complementary approaches: hierarchical/local distribution markets, distribution-level markets, and P2P trading

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paradigms – each targeting different aspects of DER participation and system-level coordination. Hierarchical and local market structures have gained significant attention as a way to align distribution network operations with the broader goals of the transmission network and wholesale market. Reference [8] proposed a hierarchical local electricity market with nested clearing layers that enforce both economic and physical constraints, demonstrating a reduction in overall costs. In that study, the second layer concentrates on budget, power balance, and flexibility constraints, while the first layer enforces power balance and capacity limits, as well as reducing line losses. Distribution-level markets are mainly used as a flexibility tool, using DERs to relieve network bottlenecks. Reference [9] considered a locational marginal pricing strategy that resulted in increasing the market-clearing price from 19.9% to 38.9% to manage congestion with the utilization of DERs. Reference [10] proposed sequential energy and flexibility markets with consideration of nodal pricing and coordination with the upstream transmission network as a potential reserve capacity buyer. The P2P trading can be categorized based on its operation coordination with other peers into three groups of fully P2P, community-based P2P, or hybrid P2P. Reference [11] provided a comparison of P2P market structures in a test case, where the economic motivations for a fully P2P design and the impact of community in community-based P2P and hybrid P2P markets are shown, where the fully P2P market achieved the best economic solution. In [12], a decentralized agent-based fully P2P market is considered in coordination with the DSO, establishing energy security of network operations. In [13], a platform was developed for local energy market designs with consideration for a centralized dispatch, distribution locational marginal pricing, bilateral fully P2P markets, and flexibility.

As the electrical network architecture transforms to accommodate DERs, changes in the electricity market structure warrant further investigation. At the moment, there is no consensus on the distribution-level electricity market structures or their viability in combination with other electricity markets. Hence, in this study, the energy market configurations are investigated, including the transmission-level wholesale market, distribution-level market, and P2P market, which helps demonstrate the potential and shortcomings of each market. Accordingly, we examine the addition of P2P transactions and a new distribution-level market to the existing wholesale market, and compare their integration with the traditional wholesale market across four scenarios to validate their viability.

II. METHODOLOGY

The cost function is the total transactions, calculated by (1).

$$J^{Total} = J^{TSO} + J^{DSO} + J^{P2P} \tag{1}$$

in which

$$J^{TSO} = \left(\sum_{g\epsilon G} \lambda_g^{TSO} \cdot D_g^{TSO}\right) + \left(N_G^{TSO} \cdot SF_{Grid}^{TSO}\right) \tag{2}$$

$$J^{DSO} = \left(\sum_{p\epsilon P} \lambda_p^{DSO} \cdot D_p^{DSO}\right) + \left(N_P^{DSO} \cdot SF_{Grid}^{DSO}\right) \tag{3}$$

$$J^{P2P} = \left(\sum_{n,m\epsilon Q} \lambda_{nm}^{P2P} \cdot D_{nm}^{P2P}\right) + \left(\sum_{n,m\epsilon Q} SF_{Grid}^{P2P} \cdot D_{nm}^{P2P}\right) \tag{4}$$

where

$$\underline{D^{TSO}} < D_g^{TSO} < \overline{D^{TSO}} \tag{5}$$

$$\underline{D^{DSO}} < D_p^{DSO} < \overline{D^{DSO}} \tag{6}$$

$$\underline{D^{P2P}} < D_{nm}^{P2P} < \overline{D^{P2P}} \tag{7}$$

$$D_{nm}^{P2P} \geq 0 \tag{8}$$

$$D_{mn}^{P2P} \leq 0 \tag{9}$$

$$D_n^{TSO} + D_n^{DSO} + \left(\sum_{m\epsilon Q} D_{nm}^{P2P}\right) = D_n \tag{10}$$

$$\left(\sum_{g\epsilon G} D_g^{TSO}\right) + \left(\sum_{p\epsilon P} D_p^{DSO}\right) + \left(\sum_{n,m\epsilon Q} D_{nm}^{P2P}\right) = D^{Total} \tag{11}$$

$$\sum_{g\epsilon G} PG_g + \sum_{p\epsilon P} PG_p = \left(\sum_{g\epsilon G} D_g^{TSO}\right) + \left(\sum_{p\epsilon P} D_p^{DSO}\right) \tag{12}$$

where J is the total cost of transactions ($), λ is the electricity price ($/MW), D is electricity demand (MW), PG is power generation (MW), N is the number of participants in the market, and SF is the service fee. Also, G, P, and Q are the sets of TSO, DSO, and P2P market participants, respectively. Equations (2)-(4) are the TSO, DSO, and P2P market transactions, sequentially. Market capacity limits are defined in (5)-(7). Equations (8) and (9) are the sale and purchase direction constraints for P2P transactions denoted by D_{nm}^{P2P} and D_{mn}^{P2P}, since every transaction in the P2P market has a corresponding seller and buyer. Equation (10) ensures that each node's demand is supplied by a combination of markets. Also, (11) guarantees that all the demand gets supplied. The demand and supply balance is depicted in (12).

The supply curves for the DSO and TSO markets are modelled by (13) and (14).

$$\lambda_{(PG)}^{TSO} = a^{TSO} \cdot e^{(b^{TSO} \cdot PG)} + c^{TSO} \cdot e^{(d^{TSO} \cdot PG)} + e^{TSO} \tag{13}$$

$$\lambda_{(PG)}^{DSO} = a^{DSO} \cdot e^{(b^{DSO} \cdot PG)} + c^{DSO} \cdot e^{(d^{DSO} \cdot PG)} + e^{DSO} \tag{14}$$

where a, b, c, d, and e are price curve parameters.

III. CASE STUDY

Four scenarios are defined to assess the market configurations as follows, shown in Fig. 1.

SC #1: All participants use the TSO market (existing wholesale market, and no new market).

SC #2: All participants use the TSO and P2P markets (P2P transactions in addition to the TSO wholesale market).

SC #3: All participants use TSO and DSO markets (a new DSO market in addition to the existing TSO wholesale market).

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SC #4: All participants have access to the TSO, DSO, and P2P markets (P2P transactions in addition to a new DSO market and the existing TSO wholesale market).

A. Data

The simulation is performed using MATLAB for each scenario, as shown in Fig. 1, where the P2P transactions, DSO market, and TSO market are cleared sequentially, reflecting a realistic approach in regards to the hierarchy of the markets. The P2P transactions are inherently decentralized and more private, hence they get cleared first, before the consumers participate in any other market. The DSO market is intended for DERs and falls at a lower network level, compared to the TSO, and it is cleared second, so that the remaining demand gets supplied at the transmission level. Finally, the wholesale market at the TSO level is cleared, as the TSO is responsible for the network reliability. A different market-clearing strategy necessitates alternative market definitions and responsibilities and may result in different outcomes. The market-clearing prices are based on the total demand in DSO and TSO markets; therefore, the DSO market must be cleared first, since the TSO manages the remaining unsatisfied demand carried over from the DSO market. Electricity supply curves are modeled based on the PJM energy market's generation offers using MATLAB Curve Fitting Toolbox, where it is assumed that the DSO market initially offers a higher price in comparison to TSO; However the TSO market surpasses DSO due to transmission and generational limitations, where it is expected that the assistance of distributed generation to be more pronounced with higher demands [14]. The simulation parameter values are shown in Table II. For demand, a total of 1,700 20 MW industrial, as well as 5,000 1 MW commercial, and 12,000 1 MW residential participants are considered, where smaller commercial and residential consumers are aggregated to be larger than 1 MW and partake in the markets, amounting to a total of 18,700 participants and 25,292 MW of demand. Electricity demand is shown in Fig. 2, where each participant is a node. The nodes are industrial, commercial, and residential participants, sequentially. To alleviate any unintended bias in the bids, without loss of generality and for the purpose of demonstrating the market potentials through the case studies, it is considered that the λ_{nm}^{P2P}, $\overline{D^{P2P}}$, $\overline{D^{DSO}}$, and $\overline{D^{TSO}}$ are uniformly distributed with maximums of \$600/MW, 1 MW, 2 MW, and 20 MW, respectively. It is assumed that generation and line capacities to be non-binding constraints, as this study is focused on normal market operation economics rather than market tools for reliability management. It is anticipated that binding constraints, such as congestion, shift the electricity supply towards integration of more expensive units, causing an increase in the electricity prices. Partial bidding is also considered in markets. The grid is assumed to be fully connected in terms of communications. The P2P transactions are random to omit any unintended bias in the P2P private arrangements. For the service fees N_G^{TSO} and N_P^{DSO}, budgets of \$250 M and \$500 M are assumed, based on the operational budget of IESO at the transmission level, and assuming a twofold budget for a new market regulator at the distribution level [15].

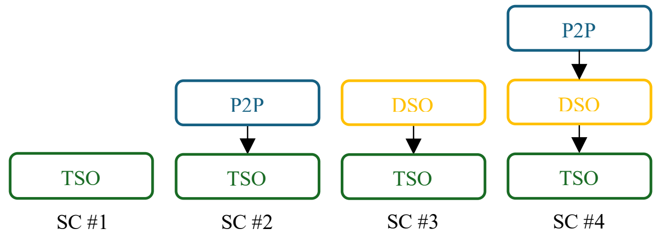

Fig. 1 Scenarios.

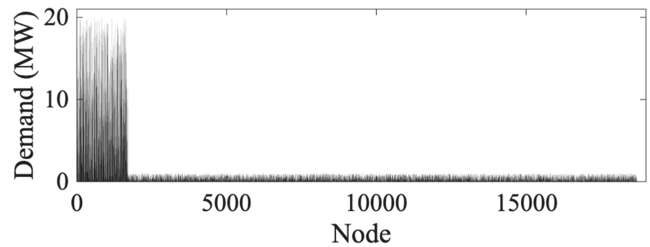

Fig. 2 Electricity Demand.

TABLE I. SIMULATION PARAMETER VALUES.

Parameter	Value	Parameter	Value
N_G^{TSO}	18,700	a^{TSO}	6
N_P^{DSO}	18,700	b^{TSO}	0.000125
SF_{Grid}^{TSO}	\$1.5261	c^{TSO}	8×10^{-12}
SF_{Grid}^{DSO}	\$3.0523	d^{TSO}	0.00106
SF_{Grid}^{P2P}	\$10/MW	e^{TSO}	20
$\underline{D^{TSO}}$	0 MW	a^{DSO}	3
$\overline{D^{TSO}}$	20 MW	b^{DSO}	0.000120
$\underline{D^{DSO}}$	0 MW	c^{DSO}	6×10^{-12}
$\overline{D^{DSO}}$	2 MW	d^{DSO}	0.00102
$\underline{D^{P2P}}$	0 MW	e^{DSO}	35
$\overline{D^{P2P}}$	1 MW		

B. Results

The total transactions and corresponding energy sales in each market for SC#1 to SC#4 are presented in Fig. 3 and Fig. 4, respectively. Also, the market-clearing price for each scenario is shown in Fig. 5, where it is assumed that the market-clearing price of TSO is larger than DSO's for a total demand of larger than 12,000 MW, based on the assumption that distributed generation will be cheaper than centralized generation in the near future due to DER utilization and transmission network congestion.

The SC #1 is the base scenario, assuming that smaller participants are enabled to take part in the wholesale market by aggregators. In this scenario, supplying all the demand solely through the TSO wholesale market has a total cost of \$4,205,591 for 25,292 MW of total demand with a market-clearing price of \$165.16/MW. This scenario represents the centralized generation at the TSO level being the most cost-effective approach. Although in response to the significant increase in demand, due to deep electrification, supplying a demand of 30,000 MW elevates the market-clearing prices exponentially to around \$800/MW. In other words, approximately 18% more demand can cause a 385% increase in the price of electricity, suggesting that centralized generation loses its original intent as the demand grows rapidly.

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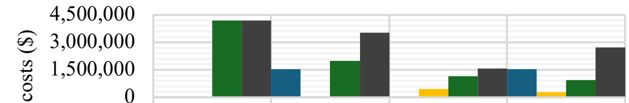
In SC #2, with consideration of P2P transactions in addition to the TSO wholesale market, the TSO and P2P transactions make up 43.77% and 45.23% of the total transactions of $3,515,207, respectively, which is 16.41% more cost-efficient in comparison to SC #1, and has a market-clearing price of $95.94/MW. As more DER is integrated in the distribution network and P2P transactions, the energy sales in the TSO wholesale market decreased. In other words, 19.72% of the total demand is transferred to P2P transactions with an average P2P transaction price of $308.49/MW, where P2P transaction price is expected to be more expensive than wholesale, because P2P transactions do not benefit from less expensive centralized energy production.

In SC #3, the DSO market is accompanying the TSO wholesale market, where the DSO and TSO markets account for 27.48% and 72.52% of total market sales of $1,587,218, respectively, which is 62.26% less expensive than that of SC #1. The market-clearing prices in the TSO and DSO markets are $43.53/MW and $67.69/MW, respectively. The DSO market hosts 34.43% of the total demand, which helps pull back on reaching the exponential rising section of the "Hockey Stick" shaped electricity production curve of the TSO market.

In SC #4, with consideration of all markets together, the P2P, DSO, and TSO transactions form 56.16%, 9.72%, and 34.12% of total transactions of $2,740,105, respectively, which is 34.84% cheaper in comparison with the base scenario of supplying electricity merely through the wholesale market at the TSO level. In comparison to SC #1, 19.72% and 59.89% of the total demand shifted from the TSO market to P2P and DSO markets. The market-clearing prices for the TSO and DSO markets are $59.85 and $40.57, respectively. For comparison purposes, the P2P transactions are considered the same as in SC #2.

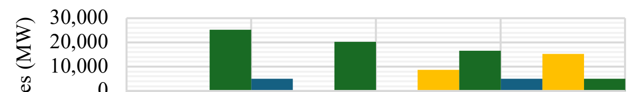
It is also important to note that the market-clearing prices of TSO and DSO markets are based on their corresponding supply and demand. With the addition of new markets that partially supply the demand, the market-clearing price of the TSO wholesale market continuously decreases, as shown in Fig. 5. In the joint operation of TSO and DSO markets (SC #3 and SC #4), shifts away from the market-clearing price of SC #1 and close to the intersection of their supply curves, which demonstrates how a new market helps settling the electricity price, supplying the demand at a lower cost, and avoiding the exponential increase of the electricity price.

In order to demonstrate how the total demand level and DSO service fee impact the results, sensitivity analyses have been performed for the best scenario (SC #3), as shown in Figs. 6-8, where growth in total demand causes an exponential increase in total costs and sales, although changing the service fee has a minute impact on the DSO total costs. Doubling the total demand increases total costs in the DSO and TSO markets by about 2.5 and 439.2 times, respectively, while total sales are doubled in both markets, indicating a very high sensitivity of the TSO market to total demand. Conversely, multiplying the DSO service fee from 0.2 to 2 times alters DSO costs and total market costs by approximately 10-13% and 3%, respectively.



	SC #1: TSO	SC #2: TSO + P2P	SC #3: TSO + DSO	SC #4: TSO + DSO + P2P
P2P	0	1,538,762	0	1,538,762
DSO	0	0	436,162	266,292
TSO	4,205,591	1,976,445	1,151,056	935,051
Total	4,205,591	3,515,207	1,587,218	2,740,105

Fig. 3 Total costs in each market and for each scenario.



	SC #1: TSO	SC #2: TSO + P2P	SC #3: TSO + DSO	SC #4: TSO + DSO + P2P
P2P	0	4,988	0	4,988
DSO	0	0	8,709	15,147
TSO	25,292	20,304	16,583	5,157

Fig. 4 Total quantities of electricity in each market for each scenario.

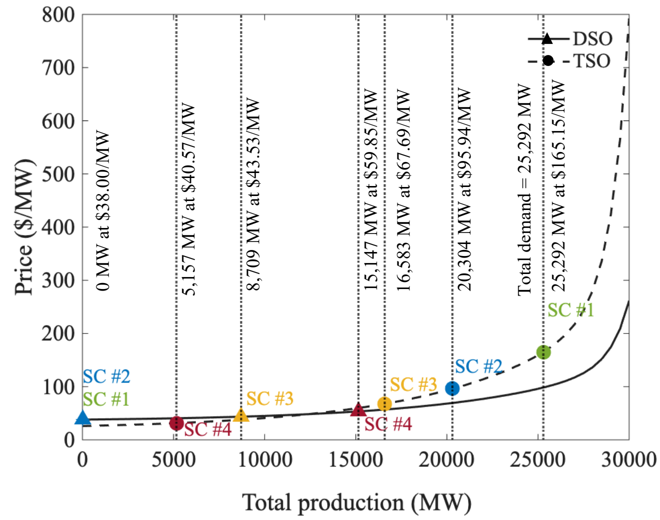


Fig. 5 Market-clearing price for DSO and TSO for each scenario.

IV. Discussion

Relying solely on the TSO as we do today, prices are expected to escalate exponentially (SC #1). The introduction of DSO and P2P markets helps moderate costs by decentralizing and diversifying the supply, where the combination of TSO and DSO markets yields the lowest total cost among the four scenarios, as shown in SC #3. The proposed model demonstrates when DSO and P2P are advantageous and proves their value.

P2P transactions need to be treated carefully. In the scenarios above, P2P performed well compared to TSO because P2P was able to displace more expensive generation units that would have otherwise been dispatched in their absence. However, the P2P market did not perform as well as the DSO because its costs could not compete at a larger scale. Therefore, the value of P2P

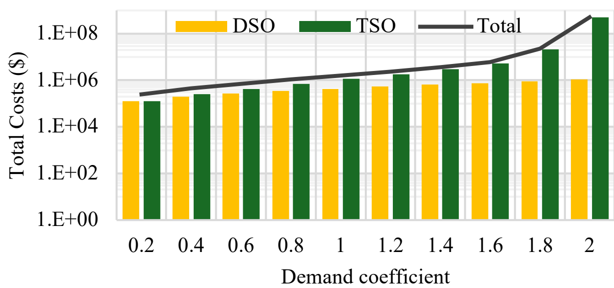


Fig. 6 Total costs in each market with respect to Demand in SC#3.

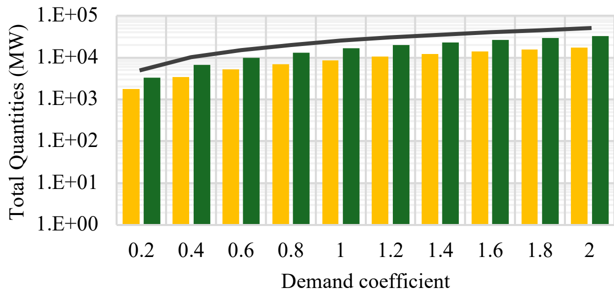


Fig. 7 Total quantities of electricity in each market with respect to Demand in SC#3.

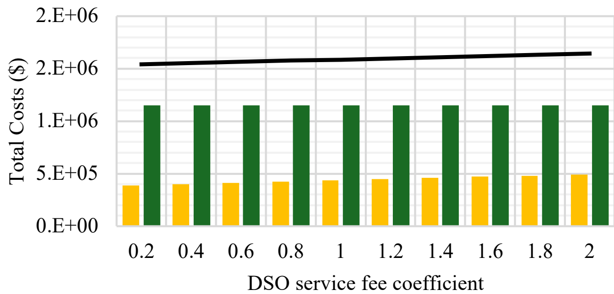


Fig. 8 Total costs in each market with respect to DSO service fee in SC#3.

is highly sensitive to the specific situation, and its use should be deployed with care.

V. Conclusions

In this study, the optimal electricity market configuration is investigated considering the integration of DERs. The simulation results show that the introduction of a market at the DSO level alongside the existing wholesale market yields the most economic option. In contrast, relying exclusively on the traditional wholesale market at the TSO level represents the least economic approach. Although the P2P market is comparatively more expensive than the DSO market approach, it is beneficial in supporting DER integration and reducing the overall costs of supplying the load by complementing the conventional wholesale market.

The proposed model and developed framework of this study serve as a tool for policymakers, regulators, and system operators to evaluate and identify the most suitable market structure. The model can be adapted to different regional electricity market conditions, and allows for comparison between various combinations of localized trading (P2P), distribution-level flexibility (DSO), and wholesale balancing (TSO).

Future work should focus on effective coordination between TSO, DSO, and P2P markets, which is crucial to harnessing DER integration.

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