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RESEARCH ARTICLE

# Local Electricity Market Design Utilizing Network State Dependent Dynamic Network Usage Tariff

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**ABSTRACT** The new technologies emerging in the energy sector pose new requirements for both the regulation and the operation of the electricity grid. Revised tariff structures and the introduction of local markets are two approaches that could tackle the issues resulting from the increasing number of active end-users. However, a smooth transition from the traditional schemes is critical, thus creating the need for solutions that can be implemented in the current circumstances. This paper proposes a local market concept and a corresponding dynamic tariff system, which can not only be operated parallel to the current retail market, but which also considers possible interactions between the two markets by taking into account the estimated state of the network. The participants of the market can trade energy peer-to-peer via a platform that allocates proper network charges to all transactions. The calculated tariffs consider the physical effect of the transactions on the grid in terms of nodal voltage deviations, branch current flows, and overall system losses. The proposed method is tested and compared to the currently existing local market approach on the IEEE European LV test feeder through market simulations. The results imply that knowledge on network state prior to trades can increase the correctness of network charge allocation. With the proper tuning of DNUT (Dynamic Network Usage Tariff) components, the end-users can even realize larger surplus compared to other local market models, while the security of network operation is also ensured.

**INDEX TERMS** Congestion management, dynamic tariff, energy trading, local market, peer-to-peer, trading platform.

## I. INTRODUCTION

The electric power system is subject to radical changes that are driven by the disruptive advancements in technology, such as household generators, storages or electric vehicles. However, power grids and regulators are slow to respond to these novelties. One issue, in particular, is the state of distribution systems, since most of the new technologies can be tied to the end-users or so-called prosumers. Currently, these participants of the grid are considered as passive actors, but they become more and more active, thus generating a need to rethink traditional retail market structures and accompanying network tariffs, such as volumetric and capacity based measures [1].

The research presented in this paper aims to develop such market solutions that enable innovative grid services to improve the connection of DSOs and prosumers. In other words, the goal of this work is to find a solution in which prosumers can trade energy between each other to gain economic benefits. The constraints posed by the physical network (which may change in a short time) should also be taken into consideration by redefining network usage tariffs. Moreover, transactions that improve grid stability, efficient grid usage and energy quality should be incentivized. Nonetheless, the developed structure should be ready to be implementable in the regulatory environment and operational circumstances present in the European market structure.

In the context of these expectations, three main approaches have been identified in the literature (often present at the same time) that address the aspects above:

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- new tariff structures for retail markets,
- locational marginal pricing for distribution systems,
- creating local markets (or in a special case: peer-to-peer markets), which enable prosumers to trade locally generated energy with each other.

On the traditional European retail market, prosumers pay energy prices to the service provider they are contracted with, and network charges to system operator companies, which are responsible for energy transmission and distribution. The main goal of a redesigned tariff structure is to incentivize consumers to shift their load according to the current state of the network by altering the respective network charges. A considerable amount of papers have addressed this topic, from which two are relevant here: [2] proposes a simple time-of-use (ToU) tariff, named "peak coincidence network charge", while [3] provides a game-theoretic approach to peak reduction by utilizing a flat-rate tariff. Although these tariffs mean an improvement from the operational perspective, the concept of cost-causality and dynamic behavior is missing. This means that tariff design solely cannot address some of the main issues of system operation.

Another approach, in the US, to consider and quantify network use is to handle energy and grid prices jointly. Distribution locational marginal pricing (DLMP) is a method which distinguishes prosumers based on the state of the network, and in which energy and network prices are inseparable. The DLMP can be derived from a standard optimal power flow (OPF) problem [4], a method that is verified to be feasible in electronically controlled distribution systems [5]. In the literature, there are several options to upgrade this method. One direction of development is to ensure that the OPF has a solution. This can be achieved using a quadratic programming model [6], by the introduction of unbalanced AC OPF [7], by the linearization of the OPF problem [8] or by the relaxation of the AC OPF to ensure its convexity [9]. Other directions include utilization of the connection with the wholesale energy market [10], consideration of nodal voltages [11] and reactive power flows [12], or the application of stochastic models for renewable generators [13]. Several LMP methods are compared in [14].

The DLMP is a promising approach for the reinvention of distribution system operation, and can be considered the fundamental basis of our work. However, since the method is based on optimization, active involvement of an operator (e.g. the DSO, i.e. the Distribution System Operator) is needed for the local trading to be successful. Another issue is that the concept of locational marginal pricing is yet to be accepted by EU regulators, thus making the implementation harder.

The concept and main attributes of local markets are summarized in [15] while [16] provides a detailed account of their introduction during the course of a specific project. The main idea is to create the opportunity for prosumers to trade with each other either through a central entity, like in [17], based on optimization, or peer-to-peer (p2p). P2p markets have seen a large interest in research over the years that span across various fields of science [18]. The current focus areas in this topic are identified by [19] as the following: trading platform, blockchain, game theory, simulation, optimization, algorithms. The results in these fields include the incorporation of blockchain technology for increased security (an evaluation scheme for such projects is presented in [20], while [21] provides a state-of-the-art design with enhanced consideration of inter-temporal dependencies), the utilization of game theory to simulate trading [22] or to design market platforms (e.g. combined with motivational psychology [23] or a time-varying priority system [24]), or to create models for prosumer behavior [25]. In most cases, these solutions assume a "copper plate" environment, where no network constraints are used, thus trading is only influenced by energy prices. To be able to manage the condition of the physical network, consideration of the congestions and voltage issues are also important. Authors discuss providing incentives for self-consumption in [26], and the introduction of network constraints in market operation e.g. using line flow restrictions [27] and sensitivity analysis [28]. Different algorithms are developed for matching orders considering network constraints to minimize information exchange [29], even applying graph theory [30] or robust planning [31]. Only loss is considered in [10]. The handling of network constraints is a focus area in the present study, too.

Generally, p2p markets have the tools to incentivize end-users to operate in a market environment through joint energy-network price signals However in the European energy market structure, the energy market is separated from network activities, so the local market should be purely competitive based on energy or opportunity costs while the network constraints should influence the network usage tariff in an incentive way. Studies above are not suitable to fulfil both criteria. Even if using merged price signals, the local p2p market structure is more applicable for demonstration, if it can be operated parallel with an existing retail market providing incentives for the local prosumers to switch to the p2p market.

Considering network constraints in p2p market while another standard retailer also supplies consumers on the same network is a great challenge. To our best knowledge, these questions have not been addressed before, although the means of proper incentivization is a key aspect in the successful implementation of a local market framework in practice. As the literature overview in Table 1 illustrates, the proposed local markets that apply both energy and network price components are not capable of parallel operation with existing trading platforms. In essence, they all consider the network with a fixed configuration of power injections that is swiftly eliminated from subsequent calculations by the appropriate reduction of remaining transmission capacities. This thought process leads to a trading platform design that operates on a network model with zero power injections (zero base case – ZBC). In this framework, the physical flows from the transactions of concurrent market platforms (e.g. retail

**TABLE 1.** Literature overview.

| Paper | Market type | Network representation | Price components | Operates parallel with standard market |
|---|---|---|---|---|
| [2] | - | - | network | No |
| [3] | - | - | network | **Yes** |
| [20], [21] | auction | - | energy | No |
| [17], [18] | auction | - | energy | **Yes** |
| [25] | auction | - | network | **Yes** |
| [12] | auction | linearized | joint | No |
| [7], [11] | auction | in details | joint | No |
| [8], [9], [14] | auction | in details | joint | not discussed |
| [13] | auction | in details | **energy + network** | No |
| [27] | auction | line flow | joint | not discussed |
| [22], [26] | **continuous** | - | energy | **Yes** |
| [29], [30], [31] | **continuous** | in details | joint | No |
| [28] | **continuous** | **linearized** | **energy + network** | No |
| [10] | **continuous** | in details | **energy + network** | No |
| *this paper* | **continuous** | **linearized** | **energy + network** | **Yes** |

market) always remain hidden. Therefore, the framework has to be modified to allow parallel operation.

The aim of the present paper is to bridge the aforementioned knowledge gap by the following contributions to local markets and dynamic tariffs:

- A low-voltage (LV) local market platform is introduced, which can be co-operated with the traditional retail market, or even as a standalone system for trading locally. The parallel operation is based on the estimated state of the network for every 15-minute interval.
- A novel dynamic network usage tariff system (DNUT) is built that maps the state of the network to the market platform. This tariff is allocated on prosumers based on the effects of the transaction in terms of nodal voltages, branch currents, and system losses.
- The tariff components can be subjects to change during real-time operation based on the estimated state of the distribution network (if trades imply power flows that represent excessive values to the estimated loads and generations).

The operation of the local market platform and the attributes of the DNUT components are showcased through market simulations, using the IEEE European LV test feeder from [32].

This paper is organized as follows. Section II describes the local market concept and the incorporated calculation methods in detail. The attributes of the proposed market scheme and tariff structure are evaluated through market simulations in Section III. Finally, Section IV concludes this paper and provides insight into the continuation of this research.

## II. MODEL

### A. LOCAL MARKET CONCEPT

The proposed local market has similar attributes to the intraday wholesale electricity market. Trading is continuous to bridge possible liquidity issues. Quarter-hourly (QH) products are used, where a minimum limit for traded energy is 1 Wh.

One key feature of our local market structure is that it can be operated in parallel with the traditional retail market. This means that the participation of prosumers is completely voluntary and is driven by profit-maximizing behavior. However, an accepted or hit order in the local market forms an obligation for both parties in the trade. The settlement is based on measurements in the given QH.

A trading platform is developed to connect all participants of the market, which might include consumers (prosumers), small-scale generators, and storage owners. The platform is responsible for handling order submission and matching as well, while it also performs settlement after physical delivery. Both supply and demand orders are composed of energy price and quantity. Dynamic network usage tariff charges are calculated for every pair of participants considering the actual state of the network. This fee is added to the price of the order and is shown on the market platform.

The DNUT depends on a base case, which is the forecasted power generation and consumption data in the system (which determines the nodal voltages and branch currents) for the actual QH. The corresponding DSO plays a key role in defining the DNUT components so that the resulting charges match the DSO's expectations in terms of how much it wishes to incentivize the grid supporting measures of participants (e.g. voltage regulation, alleviation of congestions).

A more detailed description of operation is given in the following subsections, starting with the calculation methods, developed for the local market.

### B. CALCULATION METHODS

#### 1) SENSITIVITY MATRICES

The DNUT considers the state of the network, which implies a large number of load-flow calculations to be carried out on the platform throughout the intraday operation. Therefore, sensitivity matrices are introduced to place the computational burden of load-flows before the trading period. This is done by examining voltage and current deviations from the aforementioned estimated initial state, as a function of energy exchange between each prosumer and the main grid (i.e. the slack bus). Through fitting a first order polynomial using the least-squares method (linearization) to the results of the load-flow, a voltage and current sensitivity factor (VSF, CSF) can be gained. These factors describe the network response to changes in energy injections and drains at prosumer nodes caused by transactions. Eq. (1) shows the linearization method for a single VSF value (CSFs are determined similarly, using branch currents).

$$i \in \{-\mathrm{res}, -\mathrm{res}+1, -\mathrm{res}+2, \ldots \mathrm{res}-1, \mathrm{res}\}$$
$$\sum_i \left(U_{node,i} - \mathrm{VSF}_{node} \cdot \Delta E \cdot \frac{i}{\mathrm{res}}\right)^2 \rightarrow min \tag{1}$$

where

res – resolution of load-flow output data. Voltages are calculated in $(2 \cdot \mathrm{res} + 1)$ operating points with different power injections;

$\Delta E$ – the maximum of energy injection for which the sensitivities are calculated;

$U_{node,i}$ – voltage phase RMS value of the actual node as result of the load-flow;

$\mathrm{VSF}_{node}$ – the resulting sensitivity value of the phase voltage at the given node.

These factors are ordered to obtain a VSF matrix of size nn×3np (where nn - number of nodes and np - number of prosumers), and a CSF matrix of size nb×3np (where nb – number of branches). The matrices have 3np columns to be able to consider the effect of single-phase prosumers too.

The matrices are used to estimate the current state of the grid relative to the predefined initial state (indexed with *is*) by using the following equations:

$$U_{nodes} = U_{nodes,is} + \mathrm{VSF} \cdot \Delta E_{inj} \tag{2}$$
$$I_{branches} = I_{braches,is} + \mathrm{CSF} \cdot \Delta E_{inj} \tag{3}$$

where

$U_{nodes}$ – voltage phase RMS values on each node (vector of size *nn*);

$I_{branches}$ – current RMS values on each line (vector of size *nb*);

$\Delta E_{inj}$ – injected energy for every prosumer node (vector of size 3np).

Fig. 1 demonstrates the application of VSF and CSF parameters in a small LV network with 4 three-phase symmetrical prosumers. A base case is defined, where the prosumer on node 1 (N1) is a producer, and other participants on the network are consumers. The nodal voltages and branch currents corresponding to the base case are denoted with blue. As mentioned earlier, the VSF and CSF values assume a "transaction" with the main grid. Therefore, the effect of a 0.25 kWh (1 kW for a QH) prosumer-prosumer transaction (red) between N1 and N3 is estimated as the sum of two parts: the producer supplies power to the main grid (yellow) and the consumer procures energy from the main grid (brown).

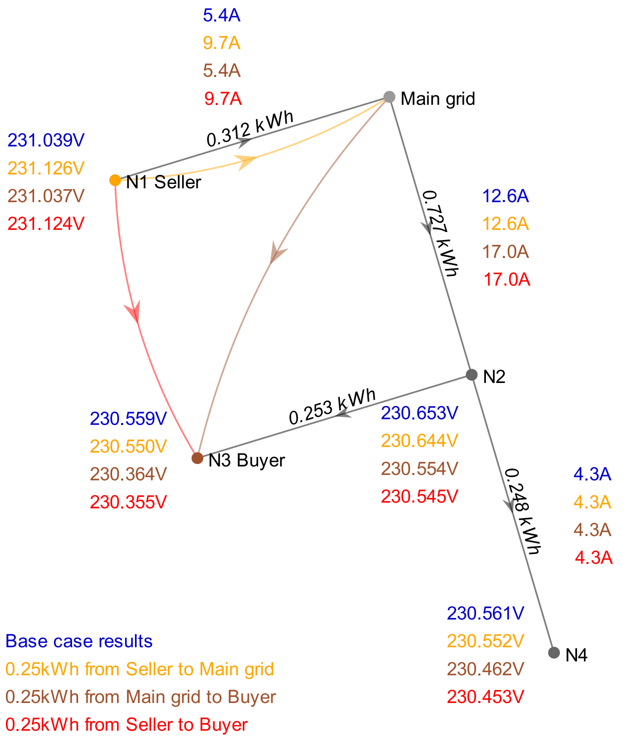

**FIGURE 1.** Demonstration of the use of VSF and CSF matrices in a small network for a 0.25 kWh transaction between two prosumers.

### 2) DYNAMIC NETWORK USAGE TARIFF

A dynamic network usage tariff structure is used to introduce the physical constraints posed by the distribution system to the market platform. When a transaction between participants is considered, the DNUT is also added to (or subtracted from) the energy price, thus representing the effects of the transaction to those responsible. This serves as an incentive to hit orders that are advantageous from the grid perspective, or hinder other orders that would move the network towards a congested state.

For every pair of prosumers (also differentiated by transaction directions) a DNUT value can be derived, thus creating a DNUT matrix with the size of the number of prosumers. The diagonal of this matrix is zero (by definition), which means that transactions between prosumers on the same network node do not use the network.

The designed DNUT is composed of three main components: current charges, voltage charges, and loss charges. A detailed description of each component is given in the following subsections.

#### a: CURRENT CHARGES

For every line in the network, a current cost is calculated, which consists of a constant and a linear part. The constant part is responsible for keeping branch currents under the given rated values.

$$\mathrm{IC}_{limit,l} = \begin{cases} 0, & I_I < I_{I,rated} \\ c_{I,limit}, & I_I \geq I_{I,rated} \end{cases} \tag{4}$$

**TABLE 2.** **The possible values of $\Delta I_l$ in eq. (6).**

| $\Delta I_l$ | | $I_{bt,l}$ | |
|---|---|---|---|
| | | $+$ | $-$ |
| $I_{at,l}$ | $+$ | $I_{at,l} - I_{bt,l}$ | $\lvert I_{at,l}\rvert - \lvert I_{bt,l}\rvert$ |
| | $-$ | $\lvert I_{at,l}\rvert - \lvert I_{bt,l}\rvert$ | $-(I_{at,l} - I_{bt,l})$ |

$$\mathrm{IC}_{limit} = \sum_{l} \mathrm{IC}_{limit,l} \tag{5}$$

where

$I_I$ – current RMS value on the line "$l$" (A)

$\mathrm{IC}_{limit,l}$ – cost of reaching the current limit on the line "$l$" (EUR);

$I_{I,rated}$ – current rating of line "$l$" (A);

$c_{I,limit}$ – limiting current charge (EUR).

Since currents represent the traffic on the electricity grid, the linear part is calculated according to load allocation on the network.

$$\mathrm{IC}_{linear,l} = c_{I,linear} \cdot \Delta I_l \cdot \mathrm{lt}_l \tag{6}$$

$$\mathrm{IC}_{linear} = \sum_{l} \mathrm{IC}_{linear,l} \tag{7}$$

where

$\mathrm{IC}_{linear,l}$ – cost of current deviation on the line "$l$" (EUR);

$\mathrm{lt}_l$ – length of the line "$l$" (m);

$c_{I,linear}$ – linear current charge (EUR/Am).

The substitution for $\Delta I_l$ can be done based on Table 2, where $I_{bt,l}$ and $I_{at,l}$ are the current RMS values before and after the transaction on the line "l", respectively. These values are calculated by using the estimated initial state and the CSF matrix that is described in section II-B1).

### b: VOLTAGE CHARGES

For every node in the network, a voltage related cost is calculated, which consists of a constant and a linear part. The constant part is responsible for keeping nodal voltages in a predefined ±10% interval around the nominal voltage (usually 231 V for LV networks in Europe), to ensure the quality of service.

$$\mathrm{UC}_{limit,n} = \begin{cases} 0, & 0.9U_{n,nom} \le |U_n| \le 1.1U_{n,nom} \\ c_{U,limit}, & else \end{cases} \tag{8}$$

$$\mathrm{UC}_{limit} = \sum_{n} \mathrm{UC}_{limit,n} \tag{9}$$

where

$U_n$ – phase RMS voltage on the node "$n$" (V);

$\mathrm{UC}_{limit,n}$ – cost of reaching the voltage limit on the node "$n$" (EUR);

$U_{n,nom}$ – nominal phase RMS voltage on the node "$n$" (V);

$c_{U,limit}$ – limiting voltage charge (EUR).

**TABLE 3.** **The possible values of $\Delta U_n$ in eq. (10).**

| $\Delta U_n$ | | $U_{bt,n}$ | |
|---|---|---|---|
| | | $\geq U_{n,nom}$ | $< U_{n,nom}$ |
| $U_{at,n}$ | $\geq U_{n,nom}$ | $U_{at,n} - U_{bt,n}$ | $U_{at,n} + U_{bt,n}$<br>$- 2U_{n,nom}$ |
| | $< U_{n,nom}$ | $2U_{n,nom} - U_{at,n}$<br>$- U_{bt,n}$ | $-(U_{at,n} - U_{bt,n})$ |

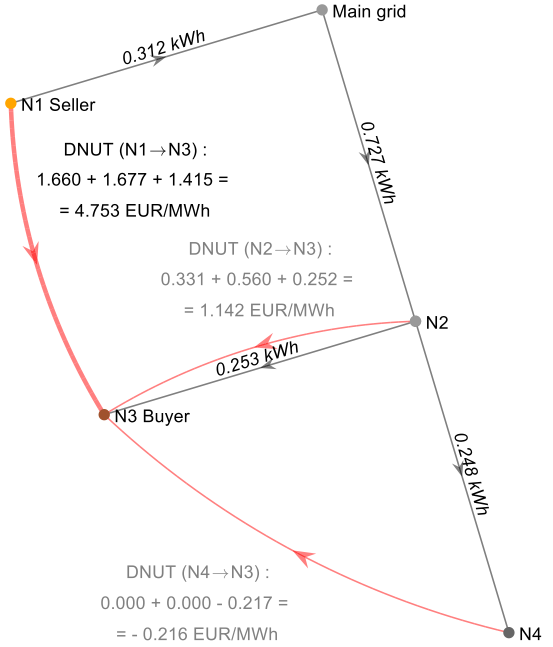

**FIGURE 2.** **Demonstration of the DNUT values for the case when the consumer on node 3 buys 0.25 kWh energy.**

The linear part of the voltage charge is used to incentivize voltage stabilizing trades (i.e. transactions that move the voltage towards the nominal value).

$$\mathrm{UC}_{linear,n} = c_{U,linear} \cdot \Delta U_n \tag{10}$$

$$\mathrm{UC}_{linear} = \sum_{n} \mathrm{UC}_{linear,n} \tag{11}$$

where

$\mathrm{UC}_{linear,n}$ – cost of phase voltage deviation on the node "$n$" (EUR);

$c_{U,linear}$ – linear voltage charge (EUR/V).

The substitution for $\Delta U_n$ can be done based on Table 3, where $U_{bt,n}$ and $U_{at,n}$ are the phase RMS voltages before and after the transaction on the node "$n$", respectively. Similarly to branch currents, these values are calculated by using the estimated initial state and the VSF matrix that is described in Section II-B1).

### c: LOSS CHARGES

In the case of network losses, only a linear charge is applied. The losses are estimated as the sum of branch losses and

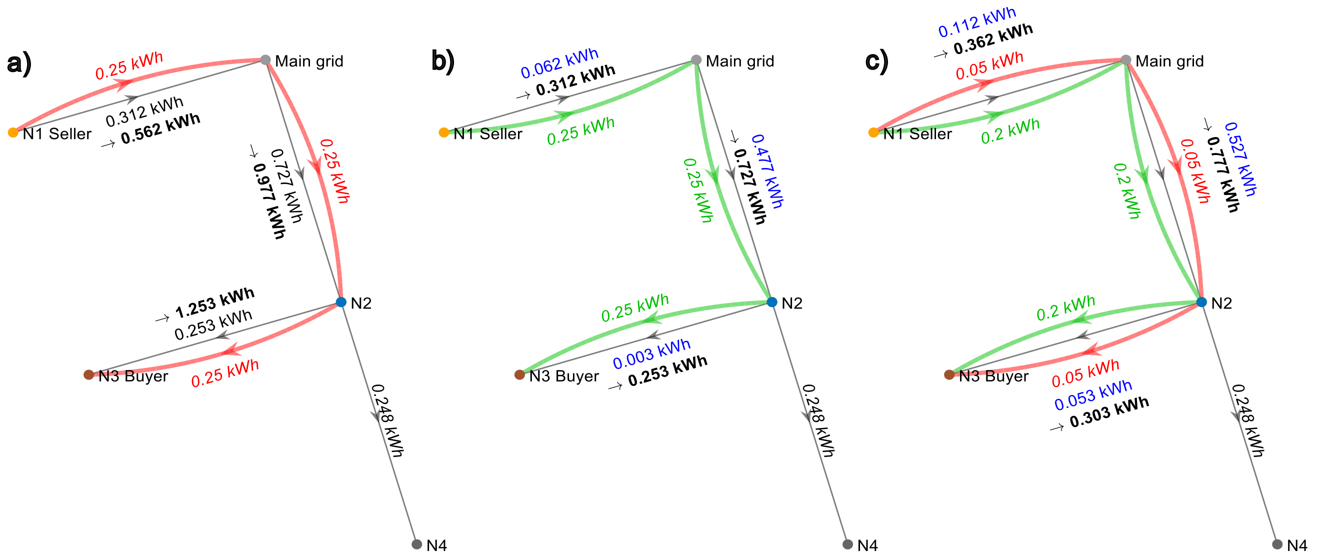

**FIGURE 3.** **Excessive (red), nominated (green), unnominated (blue), and resulting physical (bold) flows in the model.**

earthing losses for a QH in the following form:

$$P_{loss} = \sum_{l} I_l^2 \cdot R_{line,l} + \sum_{n} \frac{U_{neut,n}^2}{R_{earth,n}} \tag{12}$$

$$\text{PC} = c_{loss} \cdot \frac{1}{4} \left(P_{loss,at} - P_{loss,bt}\right) \cdot \frac{1}{1000} \tag{13}$$

where

$R_{line,l}$ – resistance of the line "$l$" ($\Omega$);
$R_{earth,n}$ – earthing resistance on the node "$n$" ($\Omega$);
$U_{neut,n}$ – neutral point RMS voltage on the node "$n$" (V);
$P_{loss,bt}$ – estimated system loss before the transaction (kW);
$P_{loss,at}$ – estimated system loss after the transaction (kW);
$c_{loss}$ – linear loss charge (EUR/MWh);
PC - cost of loss deviation (EUR).

### *d: DNUT MATRICES*

The DNUT value for two participants is constructed as:

$$\text{DNUT}_{s,d} = \frac{\text{IC}_{limit} + \text{IC}_{linear} + \text{UC}_{limit} + \text{UC}_{linear} + \text{PC}}{\Delta E_t} \tag{14}$$

where

$\Delta E_t$ – transacted energy (MWh);
$\text{DNUT}_{s,d}$ - the DNUT value for a transaction between "$s$" supplier and "$d$" consumer (EUR/MWh).

A DNUT matrix with a size of (np × np) can be established by applying (14) to every pair of prosumers. Since all the components are derived from linear equations, the calculation of this matrix is fast.

Fig. 2 shows an example of the DNUT values in the same environment as in Fig. 1, but from the perspective of the prosumer on N3, who buys energy from the supplier on node 1. The tariff components from left to right are voltage charges, current charges, and loss charges. In this case, the flows resulting from the transaction match the direction of the base case flows, which means an additional burden for the grid (i.e. increased voltage drops, line currents and losses). Therefore, all DNUT components are positive.

If the buyer on N3 had the opportunity to buy energy from N4 (considering the same base case), the active power losses could be lowered on the branch between N2 and N4. This transaction would affect the voltages and currents in a symmetrical way, so that consequent costs cancel out each other. Thus, the result is a negative DNUT.

Note that an important part of the determination of DNUT is the tuning of the defined "c" constants. A similar topic is explored in more details in [14]. However, the method of the calculation of "c" constants is out of the scope of the current paper.

## *C. ORDER MANAGEMENT*

The order book management module is responsible for showing all available orders and corresponding DNUTs to participants. Furthermore, it handles the order list and logs the completed transactions, too. Two orders can be paired if their type (either demand or supply) differs, and the following inequality is fulfilled.

$$p_d \geq p_s + \text{DNUT}_{s,d} \tag{15}$$

where

$p_d$ – price of demand order (EUR/MWh);
$p_s$ – price of supply order (EUR/MWh).

In the model, there are three ways to handle the power flow resulting from a transaction, which are described based on Fig. 3. The applied methods should be selected depending on the activity of prosumers.

In Fig. 3 a) the transaction is treated as an excessive flow (in red), which is added to the forecasted base case. This approach assumes active consumers who react to price signals

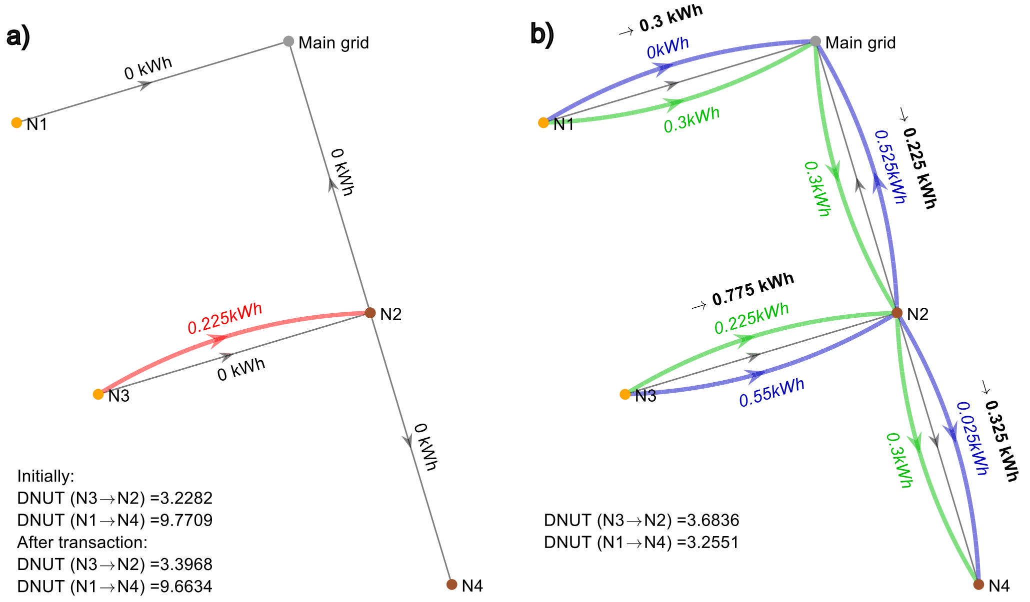

**FIGURE 4.** The comparison of existing and the newly formed local market approaches.

on the platform (e.g. cheap energy generates more demand) resulting in a new energy flow. Each trade creates a new system state, which will be the reference for further transactions. The DNUT matrix must be recalculated accordingly.

The method in Fig. 3 b) considers the transaction flow to be a part of the estimated base case, thus creating a nominated (green), and a remaining, unnominated (blue) flow. In this case, it is assumed that the market participants trade only their forecasted energy consumption/generation on the market platform to gain surplus. Each trade leaves the system state unchanged, and the initial DNUT matrix should not be updated. However, if a transaction exceeds the estimated base case, excessive flows are introduced similarly to Fig. 3 a).

The mixture of these two options is applied in Fig. 3 c), which is assumed to consider prosumer behavior more precisely. The ratio of nominated and excessive flows can be altered through the defined excessive flow ratio (EFR). In this example, the value of EFR is 0.2, which means that 80% of the transaction is nominated from the base case, while the remaining part is added to the network flows.

### *D. COMPARISON TO STATE-OF-THE-ART MARKET MODELS*

To further emphasize the attributes of our model, the ZBC approach (currently used in the local market literature) is compared to this newly formed framework, using the previously presented tools and notations of Section II. The comparison is presented on the same 4 node LV test network, where N1 and N3 are now considered as producers, while the remaining two nodes host consumption.

In this example in both cases, all prosumers submit one order each, which contain a randomly formed price and their whole estimated production or consumption for this given QH as volume. The submissions arrive in the same order. Base case power estimations are assumed to be the resultant physical flows as well.

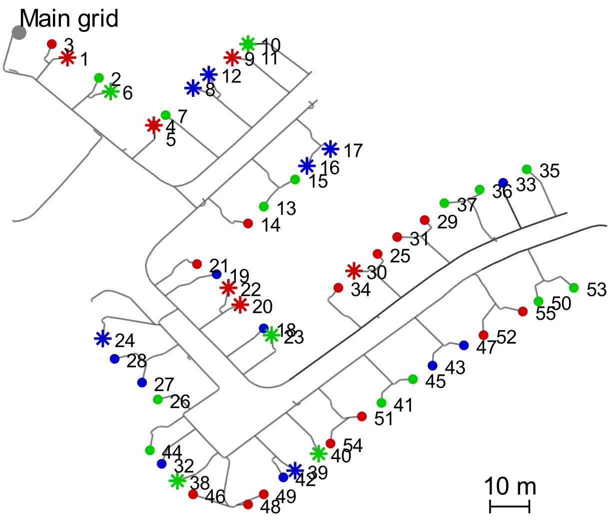

**FIGURE 5.** Network model with single-phase prosumers (red – phase a, green – phase b, blue – phase c, producers are marked by asterisks).

As mentioned earlier, currently existing local market approaches do not consider base case power flows, as pictured in Fig. 4 a) in black. Therefore, during the initial DNUT calculation, zero power injections are assumed. Based on the DNUT calculation methodology, it can be stated that the farther two nodes of the network are located, the bigger the corresponding DNUT value is. This can be seen in the bottom left corner of the figure.

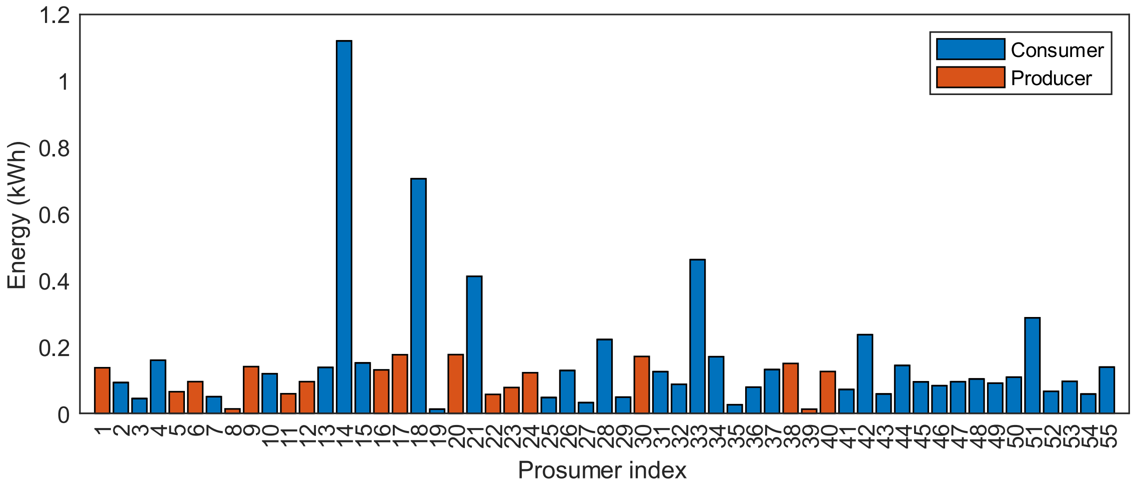

**FIGURE 6.** Base case produced (red) and consumed (blue) energy by prosumers in the given QH.

**TABLE 4.** Tunable parameters and their values in the presented simulation cases.

| Parameter | Case I | Case II |
|---|---|---|
| EFR | 0 | 0.2 |
| PAR | 1 | 1 |
| PPR | 0.6 | $[0.1, 1]$ |
| SR | $[0.1, 0.9]$ | 0.3 |
| $c_{I,limit}$(EUR/branch) | 10 | |
| $c_{I,linear}$(EUR/A) | $2.233e^{-6}$ | |
| $c_{U,limit}$(EUR/node) | 10 | |
| $c_{U,linear}$(EUR/V) | $9.57e^{-5}$ | |
| $c_{loss}$(EUR/MWh) | 122.899 | |

Using the notation in Section II-C, every transaction on the market can be modeled as excessive flow (marked in red). In this case, the DNUT matrix is to be recalculated after every executed transaction (hence the two DNUT values of the figure). Because the tariff between N1 and N4 does not reduce significantly, only one transaction is allowed.

In Fig. 4 b) the estimated base case flows (in black) are also taken into consideration, which result in modified DNUT values. Currently, a large flow (0.525 kWh) in ''N2 → Main grid'' direction is anticipated, thus generation of energy flows in the opposite direction is incentivized. It is represented in the DNUT value between N1 and N4. Due to the lower DNUT from N1 to N4 in the second case, this time a second transaction is also secured. As mentioned earlier, the base case is assumed to be the physical flows of the network, meaning that transactions will only nominate (green) parts of the estimated flows. The unnominated flows are marked in blue.

This example shows that the base case heavily influences the DNUT, which is essential to provide appropriate price signals to participants. In the case of Fig. 4. particularly, more transactions were incentivized based on the estimation (which forecasted a rather large supply). On the other hand, there can be configurations in which transactions are not incentivized due to the congested state of the network in estimation.

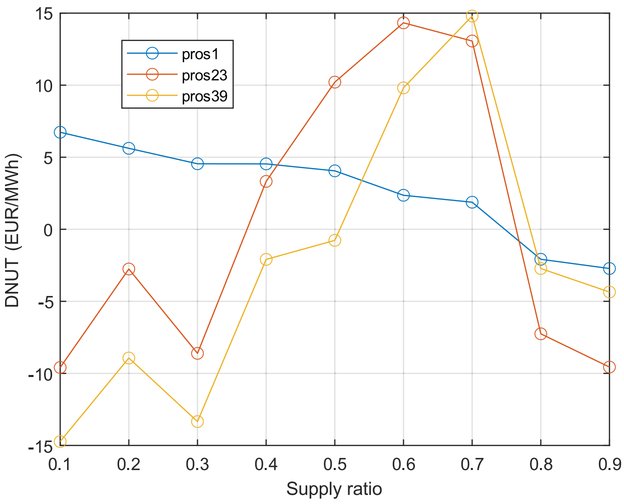

**FIGURE 7.** DNUT values between Consumer 21 (on phase a) and Producers 1, 23, 39 (on phases a, b, c, respectively).

It is also important to note that through an initial state estimation, the effect of non-participating prosumers can also be taken into consideration on the market. This further improves the exactness of incentivization.

## III. RESULTS

The operation of the local market is presented through market simulations for one specific QH. The aim of these simulations is to show the attributes of the local market framework presented in Section II. The ZBC market approach is used as a benchmark to our method similarly to Section II-D (where applicable).

The local market is operated on the IEEE European LV test feeder (Fig. 5), which is a much more complex network model than the small test grid defined for Fig. 1–4, as it contains

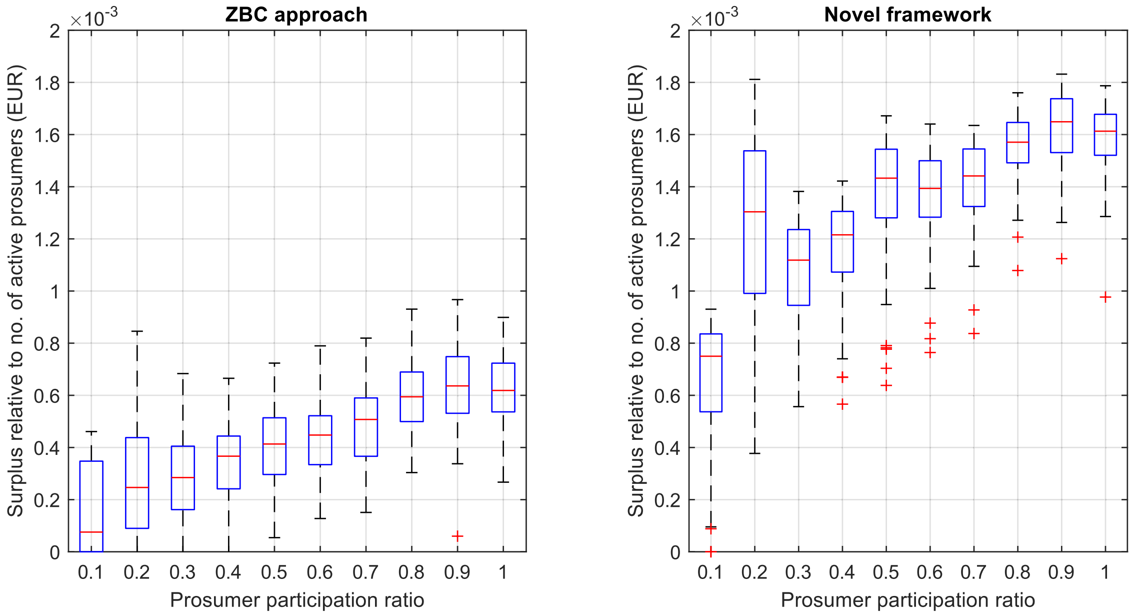

**FIGURE 8.** The change of surplus in the system as a result of increasing PPR in Monte Carlo simulation.

the neutral line. 55 loads are present in the system, each of them connecting to one of the three phases, which introduces asymmetry in the simulations. An earthing resistance of 30 Ω is considered at prosumers.

### A. GENERAL PROCESS AND SIMULATION PARAMETERS

The consumers are chosen according to a supply ratio (SR) to be switched to single-phase producers (their consumption volumes are now considered as generation). This enables trades on the local market, since without suppliers present in the system, only demand bids can be submitted.

In the market simulation, orders of the participants are created and matched automatically according to the following process:

1) A supply ratio (SR) is chosen from the [0, 1] interval, which determines the number of producers on the network. The defined generators in the case of SR $= 0.3$ (17 in total) are marked in Fig. 5.
2) A prosumer participation ratio (PPR) is defined, which determines how many prosumers (out of 55) place orders. To ensure that supply-side orders are present, one producer is always selected to take part in the market. For example, a PPR of 10% means that 5 consumers and 1 producer are active on the market.
3) A prosumer activity ratio (PAR) is applied, which determines how much energy these prosumers take to the local market platform (through orders) relative to their base case power injections.
4) The prosumers are chosen in random order to place their order.
5) The order price is adjusted to the Hungarian retail price (approximately the same for every household consumer). This consists of a 39.03 EUR/MWh energy price that is also used as feed-in tariff for small generators, and 45.43 EUR/MWh distribution network usage tariff. It is assumed that every generator can sell energy for 39.03 EUR/MWh and every consumer can buy energy for 84.46 EUR/MWh in the retail market. Therefore, to make room for more profit, prices for all orders are generated randomly from the [39.03 84.46] EUR/MWh interval.
6) One step in the simulation implies the placement of exactly one order. This new order is either added to the order book or matched if there is a suitable order in the book (that fulfills eq. (15)).

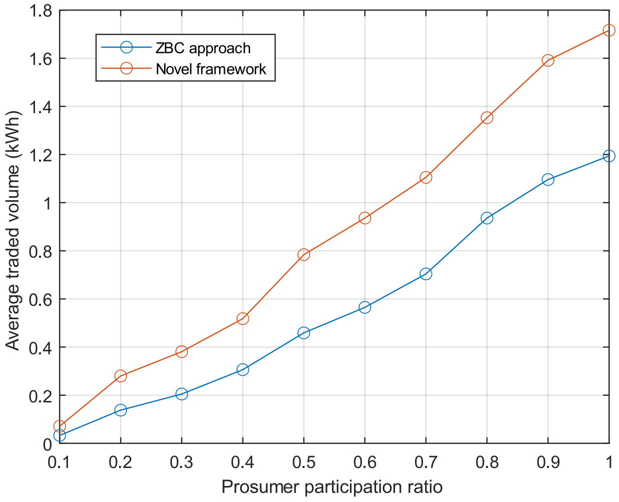

**FIGURE 9.** Mean sum traded volumes considering the two market approaches.

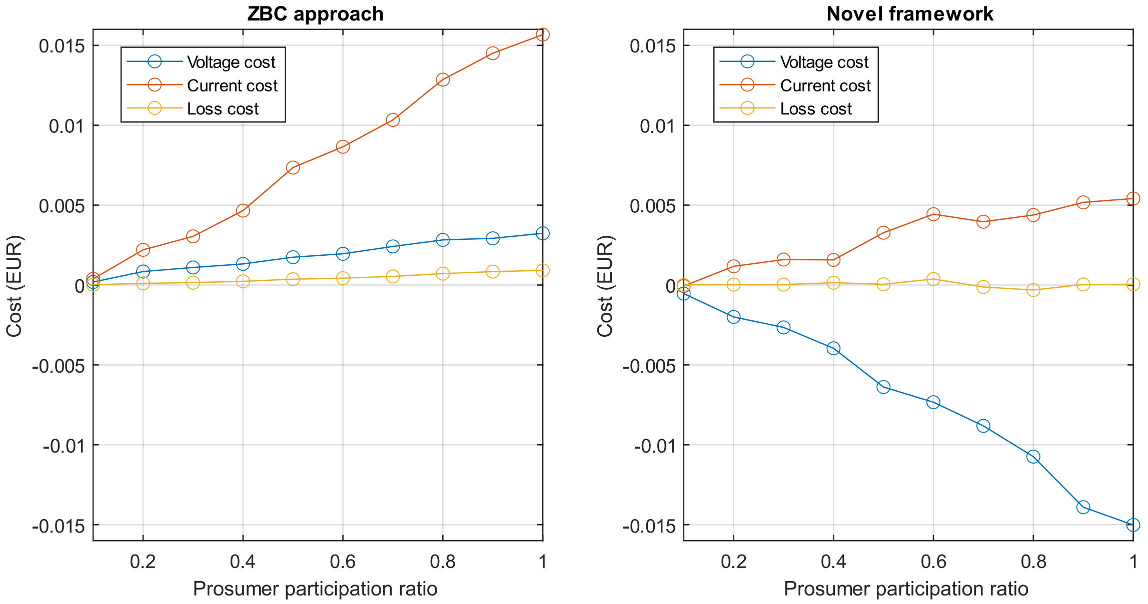

**FIGURE 10.** The mean of sum DNUT costs decomposed by physical measures as a result of increasing PPR in Monte Carlo simulation.

As mentioned earlier, the tuning of network charges is a complex problem. In this paper the costs are defined using the following method:

1) The initial DNUT matrix in the ZBC network is calculated and decomposed into three parts: current, voltage, and loss tariff matrices.
2) The standard deviations of these component matrices are normalized to 1.
3) Subsequently, the mean of these parameters can be adjusted to reach a given sum of network usage tariff. In our examples, the sum of mean DNUT values is set to 45.43 EUR/MWh, which is the distribution network usage tariff in the retail market. The fine-tuning of network charges is assumed to be the task of the corresponding DSO and is not discussed further.

The tunable parameters and their current values for the market simulations are summed in Table 4, while the base case energy injections are shown in Fig. 6.

The local market structure is tested along two dimensions, by changing SR and PPR. During these studies, other parameters from Table 4 are held constant. It is assumed that the prosumers submit their full estimated energy consumption/ generation to the local market, thus PAR = 1. In Case I, PPR is chosen to be 0.6 based on the results of a Norwegian local market case study [33].

### B. CASE I: THE EFFECT OF CHANGING SUPPLY SIDE ON THE DNUT

Through the course of this simulation, the value of SR is changed from 0.1 to 0.9 by 0.1 steps, meaning that with every iteration, additional 6 consumers are changed to be producers. Consequently, the initial state, and thus the sensitivity matrices and the elements of the DNUT matrix are reevaluated in each step.

Fig. 7 shows the DNUT values from the perspective of Consumer 21 (connecting to phase "a") to 3 suppliers (each of them connecting to different phases), respectively.

On phase "a" (between Consumer 21 and Producer 1), the DNUT value is monotonically decreasing. Considering the topology in Fig. 5, as more and more suppliers appear on phase "a", and the direction of the power flows turns towards the main grid node. The transaction between these two prosumers results in a power flow pointing away from the main grid, which is punished less and less.

The two ends of Fig. 7 can be explained similarly in case of phase "b" and "c" generators. When the number of generators is low, the direction of network flows in all three phases points away from the main grid towards consumers. The opposite is true in the case of a high supply ratio. In both scenarios, trades that alleviate the most congestions are incentivized the most. For example, at SR = 0.9 the transaction between Consumer 21 and Producer 23 causes less burdening flow between 23 and the main grid, than the relieving flow between the main grid and 21.

The simulation results for middle points (around SR = 0.5) depend on the process of simulation itself, i.e. the order, in which the consumers are switched to producers.

### C. CASE II: EFFECTS OF MARKET ACTIVITY

At this stage of the study, the effect of growing PPR (from 0.1 to 1 by 0.1 steps) is evaluated through a Monte Carlo simulation for both the ZBC approach and the local market framework, presented in this paper. A single market simulation is carried out 100 times, using a different set of orders. The participating prosumers submit exactly one order in each iteration. The change of the surplus relative to the number of participating prosumers over the course of the simulation is depicted in Fig. 8.

In general, the surplus increases with growing participation ratio, which translates into increasing relative surplus curves in both cases. The rate at which the relative surplus is growing is not constant due to several factors that are altered randomly during the simulations. This rate is influenced by the ever-changing ratio of active producers to active consumers, and the order in which trade orders are submitted and thus matched.

From Fig. 8 it can be concluded that the base case scenario is similar to the one in Section II-D. Because of the good (estimated) state of the network (considering all prosumers), on average a 2.6 times higher relative social welfare value can be reached through considering the base case energy injections compared to the ZBC approach. This is also shown in Fig. 9, where the average of the sum traded volumes on the markets are depicted.

Fig. 10 shows the mean of the DNUT costs for all transactions in the actual QH, decomposed into voltage related, current related, and loss related parts.

The network is dominated by consumption, for which the energy mainly comes from the main grid. Because of that, local trading is incentivized throughout the simulation, resulting in negative DNUT costs (i.e. participants are paid to use the local market platform). However, not all parts of the DNUT cost remain in the negative territory. The asymmetric topology of the network causes energy trades to use a big part of the grid (formerly discussed in section B); and therefore, current costs are raised for active prosumers.

As for the ZBC market, the network tariffs cannot turn negative, because relieving flows can only appear if burdening flows are caused by transactions first. The latter implies a rather large value of the DNUT to be paid, thus keeping the sum charges positive.

## IV. CONCLUSION

In this paper, a local market concept is proposed in which prosumers can trade peer-to-peer, aided by a market platform. To assess the physical effects of trades, the nodal voltages and the branch currents as a function of injected energy have been linearized, thus introducing sensitivity factors. Based on this computational method, a dynamic network tariff structure has been developed and incorporated in the prices of orders. Furthermore, the local market framework considers the estimated state of the network in order to assess transaction fees more precisely. To compare this novel approach to the models existing in the literature, market simulations were carried out. These show that the DNUTs influence the market transactions in such a way that is beneficial from the network perspective, while local generation (in a consumption-heavy area) has been incentivized. It has also been shown that the initial state of the system has a vast influence on DNUTs, and thus local trades.

Regarding the novelty of this research, results proved the ability and viability of the proposed market structure to fulfill the targeted contributions:

- The LV market platform is proved to be operable parallel to a working traditional retail system.
- The proposed DNUT structure fully considers the network state and energy flows resulting from the transactions on the local market and the estimated base case of the retail market. Furthermore, through DNUTs the platform is able to handle potential changes in the behavior of prosumers (e.g. transitioning a part of their power consumption from retail to the local market platform).
- Instead of blocking unfavorable transactions or punishing participants for burdening trades during the settlement process, the platform incentivizes participants before entering the transaction. The market is not only competitive per se, but the DNUTs also promote network-friendly transactions for a prosumer by being lower for bids placed at favorable (e.g. neighboring) nodes.

The Dynamic Network Usage Tariff based local market framework has been successfully demonstrated in the INTERRFACE project, through which the market structure was tested in three different LV sites. After thorough examination of the test results, the unknown attributes and potential barriers to the system. are expected to be uncovered.

In our future work, the limitations of the proposed local market scheme need to be alleviated. First, a precise method should be determined for base case prediction to reach appropriate incentivization. Second, as mentioned but not elaborated in this work, the tuning tariff components need to be developed to better reflect the state of the network and the needs of the DSO. Finally, the calculation of sensitivity factors is planned to be expedited by implementing a load-flow algorithm that is more suitable considering the radial nature of distribution systems.

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