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Distribution System Management Model Based on the Cooperative Concept of Unifying the Multi-Owned Networks

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Abstract: The growth of microgrids to fulfil electricity demand could lead to arguments or conflicts between the private microgrid system owners and the existing national distribution authority, especially in overlapping sales areas. The core issue identified in this paper is a distribution system management model based on the cooperative concept of unifying the multi-owned networks as a single system to ensure the natural monopoly function. This model can avoid complex wheeling charges across multi-owned grids within overlapping sales areas, in which all network users pay at the expense of the merged system charge. This paper proposes the model and shows numerical examples using a suitable distribution network pricing model to recover existing costs and plan for future system expansion. The proposed model and charging algorithm were tested on a modified IEEE 13 bus to examine their impacts. The result demonstrates that the model resolves the issues with the overlapping sales area and creates a fair scenario for the network users regarding the usage charges. Thailand is chosen as the primary reference area, as it is a country with an actual sample case for the argument.

Keywords: distribution system; wheeling charges; distribution use-of-system charges; cooperatives; overlapping microgrid

Citation: Chiraprawattrakun, P.; Leeprechanon, N. Distribution System Management Model Based on the Cooperative Concept of Unifying the Multi-Owned Networks. *Energies* **2023**, *16*, 2163. https://doi.org/10.3390/en16052163

Academic Editor: Mohsen Banaei

Received: 22 January 2023
Revised: 10 February 2023
Accepted: 13 February 2023
Published: 23 February 2023

1. Introduction

Though varying from country to country, the emergence of microgrids and distributed energy resources (DERs) worldwide has led to the development of local power markets. In most developing countries, DERs are widely known as small power producers (SPPs). The SPP programme was introduced in 1992 based on elements of the small power programme extracted from the Public Utility Regulatory Policies Act (PURPA 1978) of the United States [1]. When the SPPs are allowed to sell their excess generated capacity directly to consumers, in many cases, they decide to build their distribution systems to expand their customer bases at the retail level and eventually become a utility or a microgrid. There is a possibility that their sales areas will overlap, as mentioned in [2]. The microgrids with overlapping areas can be illustrated as shown in Figure 1.

This area could cause arguments with respect to competition and redundancy investment. For instance, as reported in [3,4], in Thailand, the argument arises from the overlapping areas between SPP networks and the existing state-owned distribution systems—especially in industrial estate areas where the networks are disconnected. It is more likely that similar issues will arise in countries with similar power sector structures to Thailand, such as Cambodia [5] and the Philippines [6]. Therefore, this requires a study of how to manage the microgrids and the state-owned distribution systems in the area to keep them on a level playing field and prevent redundancy investments.

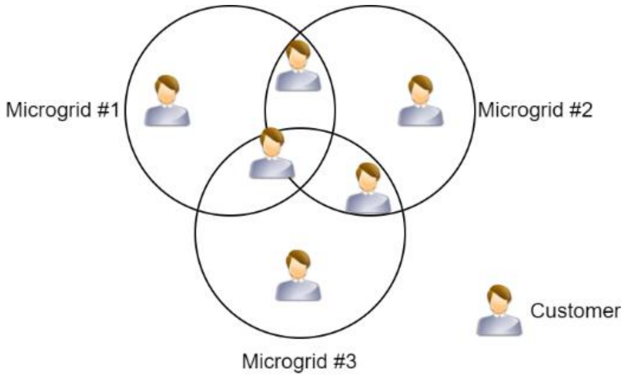

Figure 1. Microgrids with overlapping areas.

For reasons of economic efficiency, in a power market, the separate multi-owned networks should be interconnected to become "a single physical multi-owned system" under natural monopoly conditions. Traditionally, this can compensate for other network usages by employing the power wheeling model. This analogy has been practically applied in the wholesale international electricity markets in Europe and North America. However, the wheeling model may not always facilitate fair competition. For example, one utility can be treated or charged for service differently from another generator or utility—especially from a system operator in its own network [7]. Moreover, some complexities in the wheeling charge calculations can arise in many cases, e.g., the cumulative charges based on the number of networks used, electricity loss compensation, and the generation company's (GenCo's) responsibility to its customers in each network.

Therefore, Ruff [7] suggests stopping wheeling across the multi-owned transmission system and proposes a combined single transmission operator to manage the use of the system as a natural monopoly. This suggestion is similar to the concept of the national transmission authority proposed in [8]. Although the concepts in [7,8] are for the transmission network, the same scheme can be applied to the distribution system. The combined single transmission operator can refer to a combined single distribution operator in a single physical multi-owned distribution system where a part of the network is owned by a distribution company (DisCo) or SPP. To coordinate all DERs in a single distribution system, Ashok et al. [9] and Mousavi et al. [10] introduced a distribution system operator (DSO) framework to handle this activity. However, they still did not consider the case for multi-owned distribution systems. Thus, there is a need to find an appropriate management model for solving the problem of multi-owned distribution systems in order to reduce the complexity of pricing across the system.

The assumption of the management model is to combine the network owners' assets into a single distribution system. The single distribution operator will rely heavily on the cooperation of the network owners. This paper, therefore, proposes the concept of "the cooperatives" (co-ops). A cooperative is an association of persons united voluntarily to meet their common economic needs [11]. It operates based on three underlying essential principles, i.e., user ownership (the people who use a cooperative own it), user control (a democratic structure), and user benefits (fair and equitable benefit sharing) [12]. Some studies on successful cooperatives, such as [13,14], confirm that they can encourage engagement amongst their members.

One of the distinctive points of co-ops, especially for distribution systems, is the democratic structure that ensures the equitable voting rights of its members, as opposed to a company model where the voting rights depend on the number of shares. Therefore, the network owners can ensure that their ownership persists after integrating their assets into the single system. However, a fair asset assessment to determine the number of shares is still an essential prerequisite before joining a co-op due to the profit-sharing requirements.

From the studies on benefits and motivation for both cooperatives themselves and their members, as mentioned in [15,16], it is evident that the cooperative concept perfectly fits the needs of the proposed model. Therefore, this paper presents a distribution cooperative (DisCo-op) responsible for managing the integrated distribution system cooperatively. The proposed model is discussed in Section 3.

When the separated multi-owned distribution system becomes a combined single system, every network user must be subject to the same pricing methodology in order to ensure fairness and transparency.

Traditionally, a national electricity tariff—known as a uniform tariff (UT)—issued by state-run utilities is used as a benchmark for network usage pricing. Unfortunately, this is often inefficient [17], and the regulated firms tend to be overcapitalised [18]. For example, the embedded demand charge in the national electricity uniform tariff [19] consists of energy costs, transmission and distribution (T and D) systems, and a service charge [20,21]. However, it is calculated based on the postage stamp method to recover the cost of the entire national T and D system, which is the subsidy cost of the asset outside a local area. Therefore, a UT is not suitable for the combined single multi-owned system's usage charge because the demand charge or distribution charge cannot guarantee the cost recovery of the local system.

At present, there are many pricing methodologies to determine the network usage charge, such as the traditional approaches reported in [22] and several pricing approaches developed for deregulated environments in [23]. The study of Thitapars et al. [4] is an example of applying one of these traditional wheeling charge methods to solve the issues in Thailand. Most of the approaches have focused on cost allocation and regulatory provisions for natural monopoly networks. However, some methods still levy unfair cross-subsidisation charges—for example, the postage stamp and contract path methods, because they are designed based on a service-based concept rather than the actual use of the network. Therefore, it is worth applying the studies on power flow tracing and sensitivity analysis [24–27] to measure the actual usage. Yang et al. [28] proposed an approach for allocating transmission costs based on optimal power flow (OPF) for the spot market. Li et al. [29] applied sensitivity analysis for transmission loss pricing; although their study focused only on the price for transmission loss, it showed that a reasonable charge should involve the power flow tracing approach. The methods based on power tracing (e.g., in [24–27]) are fair and transparent ways to recover the actual network usage cost, but they still need to be clarified with respect to the new investment costs—particularly in terms of when and where to reinforce the network.

There are several studies concerning the methodology used to determine a system usage charge. One of the concepts is the distribution use-of-system (DUoS) charge. A similar principle to the DUoS charge design has been reported in [30,31]. According to these studies, the charges should be economically efficient, transparent, and able to recover capital, operational, and administrative costs. Both Yang et al. [32] and Mancera et al. [33] introduced the allocation for operation and maintenance—or transmission costs—of existing networks for both used and unused capacities. Jenkins et al. [34] introduced a DUoS charge for future network reinforcement and a calculation method based on the time of use and the location of users. With this approach, a network user is charged for future investments only when breaching defined critical flows. There are two suggested scenarios to obtain critical flows, i.e., the peak period (maximum demand but minimum generation) and the off-peak period (minimum demand but maximum generation). Time-of-use pricing [35] is an approach based on the elasticity of demand. It aims to signal customers to flatten the load profile, enabling investment decisions to be postponed until the right time. These concepts can be extended to network reinforcement decisions.

With the current trend, rather than focusing on the network usage cost, studies now try to focus on finding optimal energy prices or a trading paradigm between prosumers and customers instead. For example, Li et al. [2] introduced an approach based on the Stackelberg game model to find an optimal energy price, focusing on the overlapping sales areas of microgrids. Likewise, the peer-to-peer trading studies [36–40] and the Nash mechanism for distribution marginal pricing described in [41] all aim for similar purposes.

As mentioned earlier, with the increasing number of microgrids—particularly when they overlap—a redundancy of distribution systems could unnecessarily increase the network's cost. Consequently, the electricity price will be higher than it should be, even though it is optimal for prosumers and customers. As long as both prosumers and customers use a distribution network, the network usage cost is unavoidable.

When focusing on the single distributor, it is now a single, physical, multi-owned distribution network. However, as long as the network owners maintain reciprocal charging for network access, the arguments will remain, especially in the overlapping areas. Moreover, the transactions will be more complicated. Therefore, there is a need to find a more straightforward pricing methodology for the use of multi-owned distribution systems. The method must be competitive for GenCos and satisfy the network owners fairly and equitably.

Based on the gaps in the aforementioned studies, the contribution of this paper to the literature is to resolve the following two major problems:

(i) The argument between network owners in overlapping sales areas where there is a redundancy of investment in the distribution system due to the violation of the existing monopoly in power distribution.
(ii) The difficulty in formulating a fair and non-discriminatory tariff for consumers across the distribution network when multiple grid owners are willing to physically combine their grids into a single multi-owned system.

The overview of the literature studies is summarised in Table 1.

Table 1. Literature review summaries.

Literature Group	Ref.	Summary
Transmission and Distribution management model	[7–10]	The primary focus of this group is the transmission and distribution management model. These models are interesting but may need to adapt a bit for overlapping sales areas. Therefore, these concepts have been applied to develop a novel distribution management model in this paper.
Cooperatives model	[11–16]	The primary focus of this group is the concept of cooperatives. Therefore, these papers are used to support the cooperative concept of the proposed model.
Wheeling Charges	[4,22,23]	These methods are traditional methods that are currently used. A method is chosen from this group for comparison in the numerical example.
Power flows analysis and tracing	[24–29]	Some approaches are chosen to be fundamental calculations of the distribution pricing model in this paper.
Distribution Use-of-System charges (DUoS)	[30–35]	Some approaches are chosen to adapt to the distribution pricing model in this paper.
Optimal price for Electricity Trading	[2,36–41]	The primary focus of this group is to review the current trend in energy pricing studies. A gap regarding network usage pricing is identified.

The remainder of this paper is organised as follows: First, Section 2 formulates the problem to introduce a managerial model to help solve the issue of multi-owned distribution systems based on a cooperative concept called "Distribution Cooperative" (DisCo-op) to resolve the first major problem. Then, this model is discussed in detail in Section 3. To resolve the second major problem, Section 4 elaborates on and describes the use of system charges under the proposed DisCo-op model. The approach applies the principles of the concepts described in [24,34] and the qualified literature mentioned earlier. The purpose is to show how a DisCo-op collects revenue from its members to ensure system cost recovery and sufficient investment costs for future network expansion. There is no need to offer a new pricing technique for the unified system. Instead, the practical implementation based on the available pricing scheme has been investigated and only focuses on distribution and usage charges. The numerical example in Section 5 confirms that the proposed DisCo-op model can be implemented without wheeling transactions across network users. Section 6 illustrates the comparison between the DisCo-op model and the traditional wheeling model. Finally, some concluding remarks are given in Section 7.

2. Problem Formulation

As described above, distribution systems are no longer solely owned by major utilities or state-owned utilities. Instead, in developing countries, most parts of the national distribution systems (NDSs) are owned and operated by national distribution authorities (NDAs). The remaining parts of the systems, called private distribution systems (PDSs), are owned by the SPPs.

2.1. Unbundled Distribution System Management

Figure 2 illustrates the initial state of the distribution system management model after the private grid owners have joined the playing field. Every NDS and PDS has its own DSO internally, which acts independently. Without an electrical connection, there is a breach of the natural monopoly concept, causing economic inefficiency, and customers also lose the ability to choose their own suppliers.

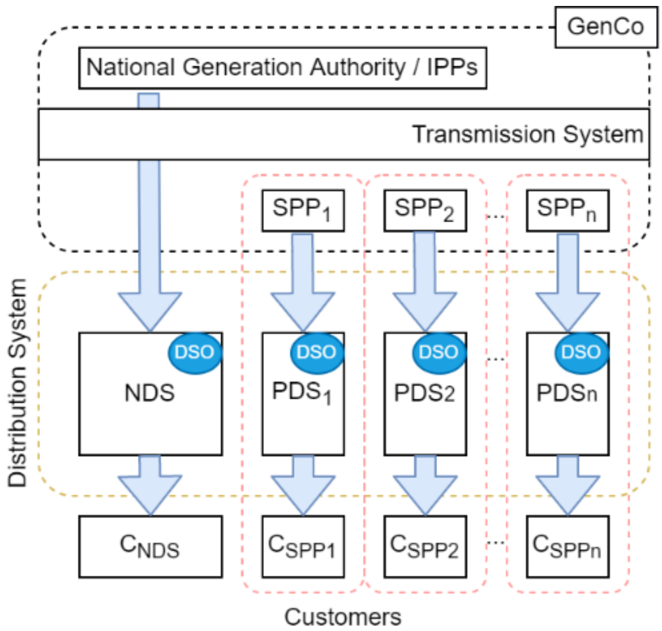

Figure 2. Multi-owned distribution systems when each network is physically separated.

Therefore, it is necessary to integrate the NDS and all PDSs to become a single, physical, multi-owned system, as shown in Figure 3. At this stage, a local power market is formed. Each grid owner can allow others to use its network. However, this requires wheeling charges to compensate the network owners for third-party access transactions.

Regarding the aforementioned difficulty of wheeling charges, a sample scenario is illustrated in Figure 4. Microgrids 1 and 2 are supposed to charge Microgrid 3 for wheeling through their distribution system to deliver the electricity to Customer 1. However, the actual transactions are: (1) Microgrid 1 charges Microgrid 2 and (2) Microgrid 2 charges Microgrid 3. Each charge rate could differ depending on the wheeling charge policy of each microgrid and its network cost. Furthermore, the more microgrids and customers there are, the higher the complexity of the transactions and calculations will be. Thus, the final cost is difficult to understand, especially for end customers.

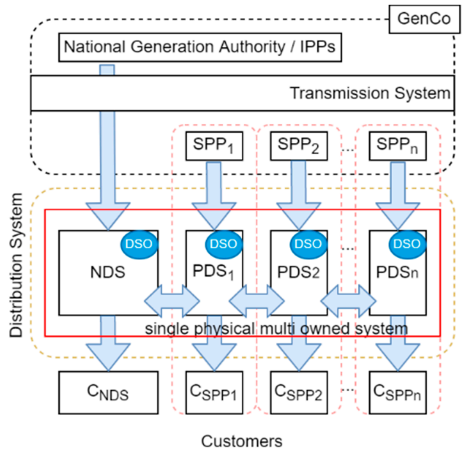

Figure 3. Integrated distribution system with a traditional wheeling model.

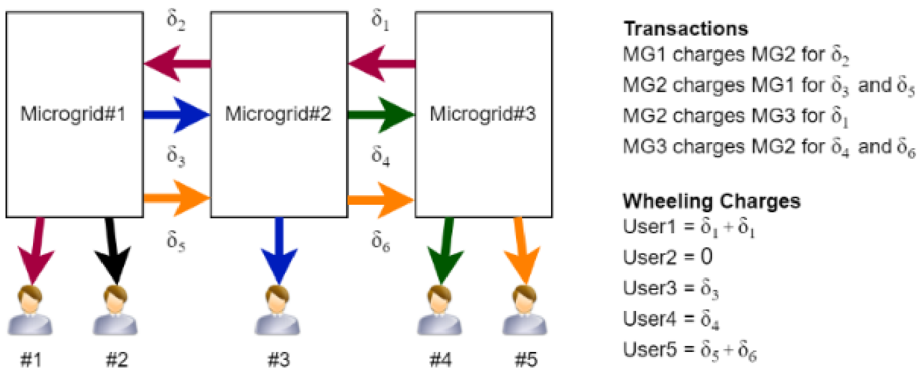

Figure 4. The complexity of wheeling charge transactions.

Therefore, to resolve these issues, this paper aims to return the multi-owned distribution system to a combined single-ownership system—in other words, a virtual natural monopoly, as suggested in [7–10]. To establish this single owner, firstly, it requires a centralised business unit to act as a juristic person representing the system asset's shareholders. Secondly, a centralised autonomous operator is required to coordinate the operation of each mini-DSO of the NDS and the PDSs.

2.2. Distribution System Management Model with Cooperative Concept

As mentioned in Section 1, the cooperative concept perfectly fits the needs of the proposed model. The juristic person should be an entity that operates under cooperative principles. Every grid owner who shares their assets with the cooperative can be treated as a member. Every member will be under the same regulations, have equal voting rights and be entitled to a dividend based on the proportion of their shared assets. This entity is called a "*Distribution Cooperative*" (DisCo-op).

For the operation unit, the definition is the same as the independent distribution system operator (iDSO). The iDSO will manage all information in integrated systems, monitor network conditions, and record the usage of each network user under a new acceptable grid code. The iDSO is not owned by any GenCo; thus, it can be assumed that there will be no conflict of interest amongst the grid owners who also own power generators. Once unfair advantages are removed, the market will be on a level playing field, minimising barriers to entry and paving the way for new players.

The proposed model for the DisCo-op and the iDSO is illustrated in Figure 5.

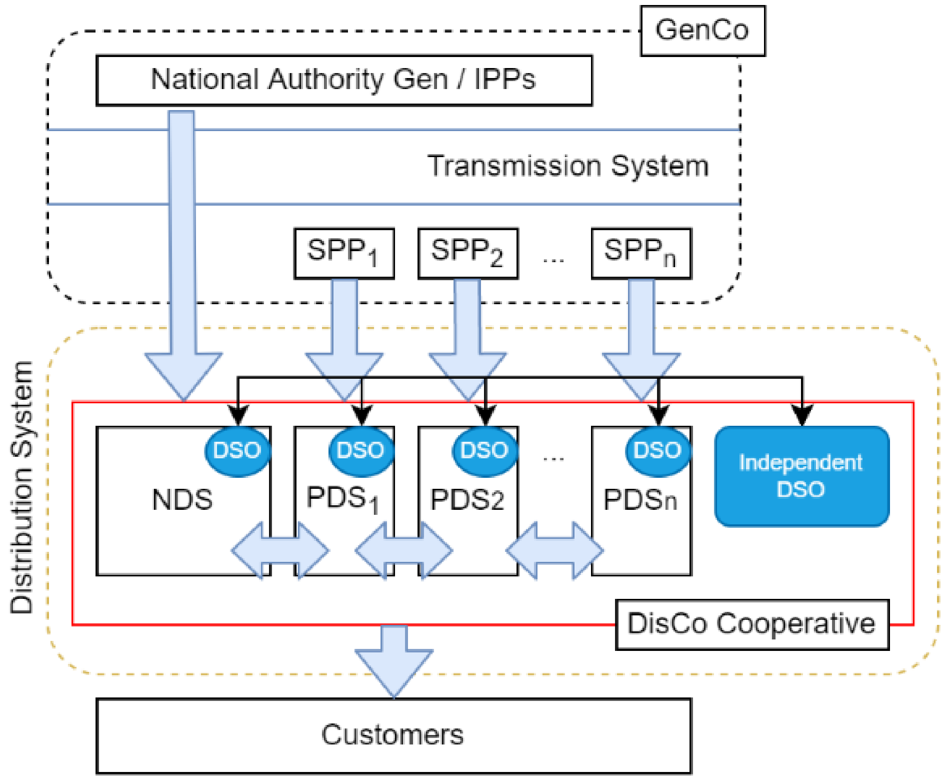

Figure 5. Distribution operation and management structure with the cooperative concept.

3. Distribution Cooperative (DisCo-Op) Model

3.1. Core Principles of Distribution Cooperatives

As outlined in [11], there are seven principles of cooperatives, as follows:

- Voluntary and open membership;
- Democratic member control;
- Member economic participation;
- Autonomy and independence;
- Education, training, and information;
- Cooperation among cooperatives;
- Concern for the community.

The cooperative's organisation is open to every member who is willing to accept the responsibilities of membership without discrimination; it is an independent and self-driven organisation run by its members in a democratic manner to make decisions and educate or help one another. Every member contributes to the organisation's business and receives profits in return in the form of dividends based on the proportion of their contribution. In addition, the organisation can also aim for sustainable community development through its policies. These principles are blended and adapted to make up the fundamentals of the proposed distribution system management model.

3.2. Functions of Distribution Cooperatives

Once the NDAs and the SPPs agree to share their network and form a cooperative body (DisCo-op), the functions of the DisCo-op are as illustrated in Figure 6 and can be described as follows:

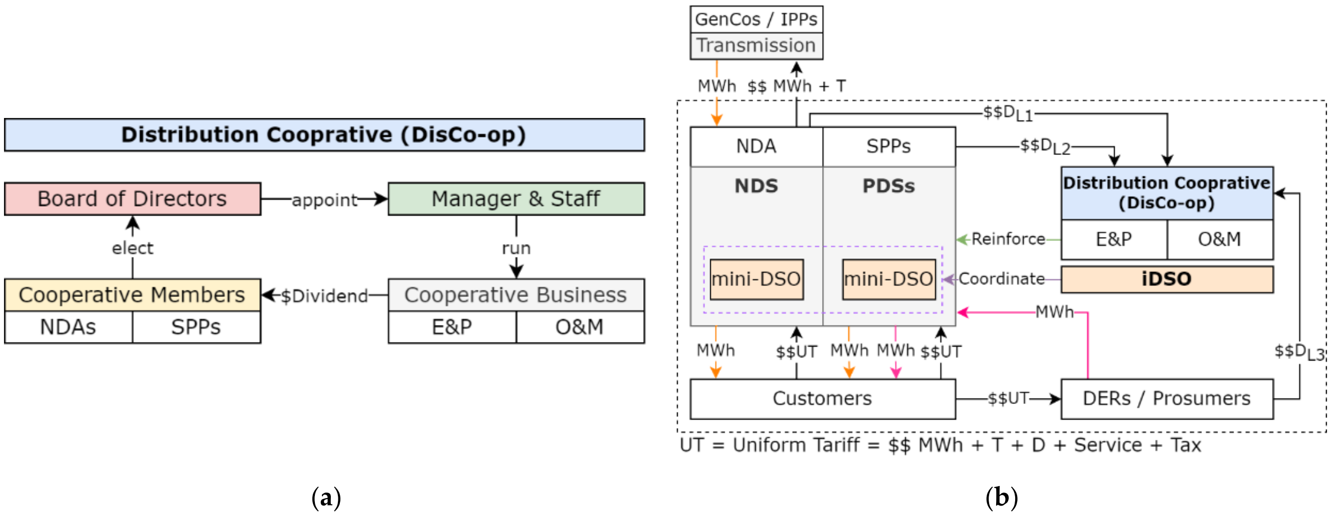

Figure 6. Distribution operation and management structure based on the cooperative concept. (**a**) Ownership function. (**b**) Operational function.

3.2.1. Ownership Function

This function is based on the fundamental cooperative concept. As shown in Figure 6a, a DisCo-op is made up of cooperative members who share their assets for mutual utilisation and mutual benefit. A central office or board of directors, which the members elect, oversees the cooperative business as a juristic person on behalf of the members by appointing managers and staff. Every member is subject to consensus regulations, under which the iDSO regulates the operational function and the DisCo-op regulates the ownership function. All earnings from shared assets are disbursed for expenses such as network operation and maintenance (O and M), administration, insurance, and miscellaneous costs. Then, the remaining capital is reserved for expansion and planning (E&P) investment as a long-term planning fund. Lastly, the net profit is distributed as a dividend. The proportion of the dividend depends on the proportion of the member's shared assets.

3.2.2. Operational Function

As shown in Figure 6b, the operational functions are divided as follows:

The DisCo-op is an entity that takes responsibility as a market facilitator. The DisCo-op can provide services not only for the members, but also for other GenCos, e.g., the DERs and the prosumers. The DisCo-op can be treated as a natural monopoly to facilitate the optimal use of distribution networks.

The E and P and O and M functions perform actions for reinforcement of the integrated network.

The iDSO is an independent entity that performs control actions for the security and reliability of the entire integrated network by working closely and in coordination with the mini-DSOs.

Even though details of how an iDSO coordinates DERs are yet to be considered in this paper, it is worth adopting the framework described in [10] and passing only its functionality of market settlement to the DisCo-op.

Therefore, a DisCo-op, with underlying support from the iDSO, can be considered as a cooperation of the NDS and the PDS owners whose primary business is providing services on the integrated distribution system; it would be a jointly owned and democratically controlled enterprise that aims to meet the owners' common economic, social, and cultural needs in a win–win strategy. With the single distribution system, the DisCo-op member can continue their business as usual without the need for confusing wheeling transactions. Moreover, its unified expansion and planning can reduce the chance of overlapping network construction in the future.

3.3. Recovery Return Concept

A DisCo-op is an organisation that must do business and distribute profit to its members. This section illustrates the big picture of the recovery return concept, which is discussed in more detail in Section 4.

With respect to the electricity trading depicted in Figure 6b, Equations (1) and (2) illustrates the operational functions as follows:

$$UT = MWh + T + D + Service + Tax \tag{1}$$

$$D - \sum_i D_{Li} \geq 0 \tag{2}$$

A customer will still pay a uniform tariff (UT) to the utilities, i.e., NDAs or SPPs, depending on the service area. Usually, from Equation (1), the UT consists of an energy charge (MWh), transmission usage charge (T), distribution usage charge (D)—also known as a "peak demand charge"—service charges (S), and tax. The NDA passes the charges for MWh and T to GenCos/IPPs, because the NDA itself is only the distribution owner and does not have a generator. For the part of distribution networks that are now taken care of by the DisCo-op, a new distribution usage charge for the local system (D_L) is calculated and charged to every network user *i*. The cost component of D_L typically consists of operation and maintenance (O&M), expenses of the DisCo-op and iDSO, and a reserve for expansion and planning (E&P) or future network reinforcement. From the customer's point of view, there are no changes because the D_L is already bundled in the UT as a part of D. In addition, with Equation (2), the D is always greater than or equal to the total D_L, because the UT rate is calculated from the whole distribution system under the NDA in the country—not just from the local system. The utilities can deduct the D_L from each customer's UT payment and then pass it on to the DisCo-op. On the other hand, from the perspective of the utilities that also own a network, rather than paying the O&M and E&P to reinforce their network, they can switch to paying only the D_L to the DisCo-op instead. The utilities that have no network can still charge for the UT from the customers, but they no longer need to pay for wheeling to the network owners. They can switch to paying the D_L to the DisCo-op.

3.4. Cooperative Members

Regarding the principles of cooperatives described in [11] and the "user benefit, user owner, and user control" concepts discussed in [12], the distribution owners—i.e., the NDAs and the PDS owners—are automatically entitled to be members of the DisCo-op. However, not every network user can be a cooperative member. The eligible cooperative members must do the same business and supply their products for mutual benefit, e.g., distribution systems.

The shareholding percentage of the owners is based on a benchmark cost of their network in the integrated system. This percentage is essential in distributing the profits back to the members as dividends at the end of the period, as shown in Equations (3) and (4).

$$Surplus = \sum_i D_{Li} - E\&P - O\&M + NRI \tag{3}$$

$$Dividend_i = Surplus \times Shares_i \tag{4}$$

It should be noted that the shareholding percentage is used only for profit-sharing and withdrawal of membership prerequisites. The voting rights are equitable amongst the cooperative members regardless of shares.

Table 2 illustrates the concept of UT payment and dividends as described in Equations (1)–(4). This assumes a 10,000 GBP net return from investment (NRI), and the NDA and the SPPs hold 47.10% and 52.90% of the shares, respectively. D in the UT is assumed to be 76 GBP per kWh per year. It is noted that the total D in UT is higher than the total D_L. However, the D_L rate for an individual user is not necessarily lower than the UT, depending on the cost and usage of each user.

Table 2. Distribution usage charge and dividend for each member.

Network Users	D_L (GBP)	E&P (GBP)	O&M (GBP)	D (GBP)
A	31.5622			58.3014
B	113.9299			108.2740
C	148.2242			466.4110
D	34.2901			77.0411
Total—NDA	328.0064	5.1000	322.9064	710.0275
E	194.2448			322.7397
F	170.0302			209.8953
G	33.0661			40.4049
H	115.1716			82.0384
Total—SPP	512.5127	0.0000	512.5127	655.0783
NRI (GBP)	10,000.0000		**Surplus (GBP)**	10,000.0000
	Shares (%)			**Dividend (GBP)**
NDA	47.10			4710.0000
SPP	52.90			5290.0000

3.5. Boundaries of the Proposed Solution

In some countries, the NDS and the NDA are required by law for social equity, including rural electrification. Therefore, the proposed model can be applied only in specific areas, such as industrial estates, where a part of the NDS can be integrated with the PDS or the area has no NDS.

In addition, the NDA may have authority by law to either stimulate the distribution system or obtain rebates from the system even though it has already become a cooperative member. Therefore, the NDA might not be able to become a cooperative member unless accepted by every member. In Section 4, an approach that can support both cases is proposed, regardless of whether or not the NDA is a member of the cooperative.

The cooperative is an autonomous organisation through which the network is operated and managed by the members, such as a holding company. Nevertheless, the cooperation between members would not be sustainable without regulations upon which every member consensually agrees. Moreover, the cooperative should still be under-regulated by a national authority organisation so that the development of the network progresses in the same direction as national regulations and the national development plan. The cooperative's regulations are essential and require a thoughtful design because the cooperative's identity and members' engagement should persist after applying the regulations. The authors assume that every member agrees on the fundamental cooperative regulations and agrees to accept the NDA as a member of the cooperative. Any additional regulations are yet to be considered in this study.

4. Distribution Use of Sharing System (DUoSS) Charges

In Section 3, the operational function of the DisCo-op and recovery return concept has been discussed. This functionality can be illustrated in Figure 6b. In this section, the recovery return concept is expanded to ensure that the DisCo-op can do distribution system business and return net investment gains to the members.

Focusing on the distribution usage charge for the local system (D_L) for DisCo-op, it must be practical for every network user and able to resolve the second problem mentioned in Section 1. In this case, the NDAs can be considered network users but hold different functionality from the SPPs and the customers. The NDAs, by law, can either be charged for network patronage or receive a rebate from the system. The rebate can be for any purpose, but there are two main reasons. The first is to compensate for support from the main grid if the electricity in the local network has a shortage or exceeds demand. Secondly, because of the exclusion of the distribution usage component in the national UT, the NDA might set up a scheme to compensate the social equity factor in the national UT from the local system with an appropriate rate instead. These charges or rebates are also considered as a requirement for the network access charge.

4.1. Distribution Use-of-Sharing-System (DUoSS)

There are three significant features to consider for the network access charge: Firstly, it should support network growth. Secondly, it should continuously maintain network reliability and recover all operating costs. Both should be calculated based on each user's contribution to a sharing system. Finally, it should compromise with the NDA in terms of its role and responsibilities. Therefore, this paper applies the concept of DUoS to come up with a novel distribution usage charge for the multi-owned distribution system, called the distribution use-of-sharing-system (DUoSS) charge, which can be expressed as follows:

$$\mathrm{DUoSS} = \sum\nolimits_t (FInvC_t + OMC_t) \tag{5}$$

The future network reinforcement cost ($FInvC_t$) is the construction cost for new lines to enhance the distribution network's capability and the efficiency of period t. This cost can be expressed as the rate per the maximum capability of the network after enhancement, in GBP/kW. Therefore, this rate is estimated based on the future value (FV) of the construction cost. In an integrated network, the cost of each circuit could differ depending on its original book cost. It is assumed that a benchmark rate is already available for each circuit, and does not focus on an approach to determine the rate in this study. A user could be charged for DUoSS according to the accumulation of the benchmark cost on each circuit used for power flow. In other words, DUoSS charges will depend on the number of circuits or the line distance.

The O&M cost (OMC_t) is calculated from the recurring costs in network operations during period t, i.e., wages, administration, network maintenance, and other miscellaneous costs (for example, see [3]). Typically, the recurring period in the calculation is annual and, thus, the cost is known as the equivalent annual cost (EAC). Nevertheless, in the proposed approach, the calculation can be performed for any period. Therefore, the term equivalent periodic cost (EPC) is used instead. Normally, the EAC can be determined by applying an annuity calculation method. However, when transforming into EPC, it should still guarantee that all of the O&M costs are recovered for that period. It should be noted that approaches to determining the EAC or EPC are not investigated in this study.

Using Equation (5), the DUoSS charge can be cumulatively calculated as a number for the defined calculation period t, and then the network users can be billed only once. The details of the calculation algorithm for each period are explained in Section 4.4.

4.2. Future Network Reinforcement Cost (FinvC)

Based on Jenkin et al.'s approach in [34], it is a general objective to recover the future network reinforcement cost. This paper magnifies this approach into DUoSS to consider the role and responsibility of the NDA, which is not a network user. This means that every party in the local network is now able to participate in the network reinforcement. The participation of each network user and the NDA can be defined as follows:

$$FInvC_{adjusted} = FInvC + Eq \tag{6}$$

$$FInvC = FInvC_p + FInvC_c + FInvC_a \tag{7}$$

$$FInvC_p = \sum(-PG_{i,p}^{off-peak} \times Y_i - RW_{i,p}) \tag{8}$$

$$FInvC_c = \sum(PD_{i,c}^{peak} \times Y_i - RW_{i,c}) \tag{9}$$

$$FInvC_a = \sum(RW_{i,p} + RW_{i,c}) \tag{10}$$

$$RW_{i,p} = PG_{i,p}^{peak} \times Y_i \tag{11}$$

$$RW_c = PD_{i,c}^{off-peak} \times Y_i \tag{12}$$

$$Y_i = \sum_{n=1}^{i} \begin{cases} y_n & ; f_n^d \geq f_n^{cf} + f_n^g \\ -y_n & ; f_n^g \geq f_n^{cf} + f_n^d \\ 0 & ; \text{otherwise} \end{cases} \tag{13}$$

$$Eq = \sum_k Eq_k \tag{14}$$

$$Eq_k = \frac{Actual\ Cost - \sum FInvC}{Actual\ Cost} \times FInvC_k \tag{15}$$

$$Actual\ Cost = \sum_n (f_n^a \times Y_{a_n}) \tag{16}$$

$$Y_{a_n} = \begin{cases} y_n & ; f_n^a \geq f_n^{cf} \\ 0 & ; \text{otherwise} \end{cases} \tag{17}$$

In Equation (6), the future network reinforcement cost (*FInvC*) consists of the cumulative cost from each network user, as expressed in Equation (7), and an equaliser presented in Equations (14) and (15) to justify the slight difference between the calculation and the actual cost.

The cost of each user can be expressed as shown in Equations (8)–(10). Typically, the future investment cost is from the future growth of the network within a certain period—the cumulative benchmark future network reinforcement rate of each used circuit, followed by deductions for rewards or penalties. The cost for the SPPs and the customers is expressed in Equations (8) and (9), respectively. During the off-peak period, the network usage rating depends on the connected generators. Therefore, the SPPs are the network users and are responsible for the cost in this period. On the other hand, during the peak period, the network usage rating depends on the demand. Therefore, the customers are the network users and are responsible for the cost in this period.

Equation (10) can be used to calculate the cost for the NDA. Unlike the SPPs and the customers, the NDA is typically a distribution system service provider, not a network user. Therefore, it is not responsible for the network usage rating. However, as mentioned earlier, in the event that the NDA has the authority to stimulate or ask for some rebates from the system, the NDA can contribute to the distribution system by offering rewards and penalties. The reward and penalty scheme aims to reduce the network usage rating, as expressed in Equations (11) and (12). Rewards are for generators in the peak periods and loads in the off-peak periods, while penalties are the opposite. Equations (11) and (12) will become a reward or penalty depending on the benchmark future network reinforcement rate.

The benchmark future network reinforcement rate at circuit i (Y_i), as expressed in Equation (13), is cumulative because the generators and loads can involve multiple networks or circuits. Therefore, the rate reflects the usage on every affected network. The decision to increase or reduce the rate of the charge will depend on the defined critical flow.

The critical flows can be defined based on the safety limit of a line's capacity. For example, if a line has a maximum capacity of 100 MW, the safety limit capacity could be 80%, i.e., 80 MW. The Y_i rate increases only on the lines where the usage equals or exceeds the critical flows based on this assumption. No future network reinforcement cost is calculated if the usage is lower than the critical flows. In other words, there is no need for further investment if the usage is lower than the line's safety capacity. The new investments can be deferred until required.

In [34], the future network reinforcement cost was calculated in two periods, i.e., peak and off-peak periods. However, the calculation can be performed for any period using the proposed method. The period can be daily or hourly, depending on the requirement or policy. The Y_i rate must be transformed into a daily or hourly rate as well. For example, if the requirement is every 12 h, at noon and midnight, the Y_i rate for these calculations should be transformed into a half-day rate.

This approach starts from system configurations, i.e., benchmarking rate (y_n) and critical flows. At a time for each defined period, a power flow analysis is carried out to identify the power flows in each line. Next, this information is used to calculate all Y_i rates using Equation (13).

It should be noted that, usually, the obtained charge and the actual cost calculated from actual flows and the Y_{a_n} rate of a circuit—as expressed in Equations (16) and (17), respectively—are the same. However, they could be slightly different due to precise calculation or technical constraints. The equaliser in Equations (14) and (15) is for justification. The expressions not only provide leverage and maintain cost recovery, but also improve the productive efficiency of the tariff. Nevertheless, the proportion of each user's responsibility will be the same.

4.3. Network Operation and Maintenance Cost (OMC)

From the perspective of network operation and maintenance, the cost for each user is defined as follows:

$$OMC = OMC_a + OMC_p + OMC_c \tag{18}$$

$$OMC_p = \sum_n \left(W_n^{om} \times F_n \times f_{n,p} \right) \tag{19}$$

$$OMC_c = \sum_n \left(W_n^{om} \times F_n \times f_{n,c} \right) \tag{20}$$

$$OMC_a = -1 \times \begin{cases} \left(OMC_p + OMC_c \right) \times \frac{\Phi_r}{1+\Phi_r} & ;\ \Phi_r \geq 0 \\ \sum_n EPC_n^{om} \times \Phi_r & ;\ \Phi_r < 0 \end{cases} \tag{21}$$

$$F_n = \begin{cases} \frac{f_n^{cap}}{\sum_k f_{n,k}} & ;\ \sum_k f_{n,k} \neq 0 \\ 0 & ;\ \sum_k f_{n,k} = 0 \end{cases} \tag{22}$$

$$W_n^{om} = \begin{cases} \frac{EPC_n^{om} \times (1+\Phi_r)}{f_n^{cap}} & ;\ f_n^{cap} \neq 0 \\ 0 & ;\ f_n^{cap} = 0 \end{cases} \tag{23}$$

$$EPC_n^{om} = EPC_n \times \Phi_{UTILISE} \tag{24}$$

$$|\Phi_r| \leq 1 \tag{25}$$

$$\Phi_{UTILISE} \geq 0 \tag{26}$$

The O&M costs should be charged to each network user according to their usage, as expressed in Equation (18). This paper uses Bialek's approach [24], which is based on Kirchhoff's current law and the proportional sharing principle, to trace and identify the power flow that each user has used in the network. Equations (19) and (20) can be used to calculate the charge amount for the SPPs and the customers, respectively. The obtained charge amount depends on the charge rate, sharing factor, and the amount of power flows used by each user in each line.

As mentioned earlier, the NDA is usually just a distribution service provider, not a network user. Therefore, the network users are only the SPPs and the customers of both the NDA and the SPPs. However, the NDA can still participate in the integrated distribution system through a regulatory policy factor (Φ_r). Accordingly, Equation (21) provides the O&M cost for the NDA while also considering the regulatory factor. This factor is discussed in the latter part of this section.

The sharing factor (F) is a special term introduced in DUoSS to indicate the line usage rating, as expressed in Equation (22). When the value of F is close to unity, it indicates that the line usage is approaching the safety capacity. If the factor often hits the safety limit, it indicates the need for a new network reinforcement investment.

The charge rate (W_n^{om}) calculated by Equation (23) is the ratio between a line's O&M cost ($EPC\ _n^{om}$) and its capacity (f_{cap_n}), expressed in GBP/kW. Each line has an individual rate. Every power flow through the line will be charged at the line rate.

When focusing only on the charge rate factor ($W_n^{om} \times F_n$), an inverse correlation is observed between this factor and the total usage of line n. The charge rate will decrease when the line usage rating increases, and vice versa. Therefore, this factor can be used to encourage the network users to use the network more efficiently.

The line's O and M cost ($EPC\ _n^{om}$) can be determined using Equations (24) and (26). The utilisation factor ($\phi_{UTILISE}$) is another factor introduced in DUoSS to indicate that the DisCo-op either subsidises or increases the cost of the network. When the DisCo-op sets the factor to be greater than unity, a premium cost will be added to the network. Normally, this is used to improve the network's reliability as a premium service provided by the DisCo-op. In addition, the factor can also be set to less than unity to subsidise the total cost of the network. Sometimes, the network may not be fully utilised, and the DisCo-op may decide to subsidise the cost of the unused capacity. The factor setup depends on the DisCo-op's policy.

The regulatory factor (ϕ_r), as expressed in Equations (21) and (25), is introduced in DUoSS to indicate the participation of the NDA in the distribution system. A positive ϕ_r indicates an extra charge to be added to the O&M costs. This extra amount will be returned to the NDA for any purpose. When ϕ_r is negative, the NDA will subsidise some of the network's O&M costs incurred by the SPPs and the customers. This can be an explicit subsidisation to stimulate or patronise the integrated distribution system area, or for marketing purposes. The positivity or negativity of this factor depends on the regulatory policy of the NDA.

The power flow tracing methods proposed in [24–27] can be used to determine the electricity that flows through the network for each load and generator. When the flows of each user are determined, the charges that are based on the flows will be fair and reflect actual network usage. For simplicity, the DC load flows can be used as a tool to illustrate the power flows in the network. A detailed power flow analysis is unnecessary because the ratio of network users is not significantly different. This concept can be applied to both transmission and distribution without changing the system configurations.

Even though the O&M cost can be independently calculated for any period, it is recommended to calculate it for the same period as the future investment cost calculation.

4.4. DUoSS Calculation Algorithm

The calculation process of the DUoSS charge for each user is illustrated in Figure 7. The process starts with the information prepared for the system profile, such as each line's capacity and cost. Then, the period for which to perform the DUoSS calculation is defined. Finally, the cost is calculated for the defined period to determine the EPC and Y_i for each circuit or line.

Once this information is promptly prepared, the calculation is performed periodically. The DUoSS charges obtained from each periodic calculation are accumulated for each billing cycle, after which the charges are reset and restarted.

4.5. Profit Sharing

The application of the cooperative concept to the operation of the proposed model is illustrated in Figure 8. One well-known feature of a cooperative is the "patronage dividends", which are those distributions of profits paid by the cooperative to their owners [42]. Patronage dividends are paid based on a portion of the business's profit. Fundamentally, the actual dividend for each DisCo-op member is based on (1) how much they shared the system's assets and (2) how much they used the cooperative's services or product purchasing. As shown in Figure 8, although the main objectives of the proposed model must be network growth and sustainability, the cooperative can manage the surplus from both expenses and the network reinforcement to make more profit as long as the primary purpose remains. Eventually, all profits will be returned to the members based on shareholding and DUoSS payment proportions.

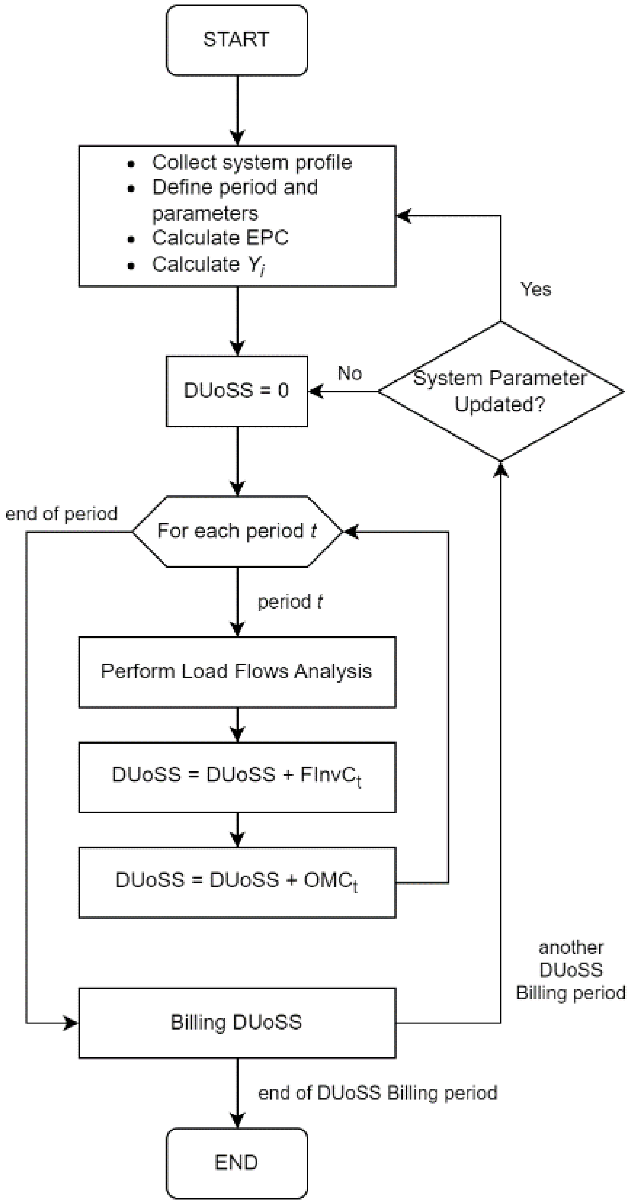

Figure 7. DUoSS calculation algorithm.

Regarding the principles of the cooperative, the second and third cooperative principles are "Member Democratic Control" and "Member Economic Participation", respectively, which describe how members invest in the cooperative and benefit from its surplus, as well as the requirement of an equitable sharing process to distribute the surplus [43]. The profit-sharing or cooperative patronage dividend can be expressed as follows:

$$Div_{i,t_d} = Surplus_{t_d} \times Contrib_{i,t_d} \tag{27}$$

$$Surplus_{t_d} = NRI_{t_d} - Expense_{t_d} - E\&P_{t_d} \tag{28}$$

$$Contri_{m,t_d} = \frac{Invest_{m,t_d} + Spending_{m,t_d}}{\sum_i (Invest_{m,t_d} + Spending_{m,t_d})} \tag{29}$$

$$Invest_{m,t_d} = Shares_{m,t_d} + \sum_j \left(FIncC_{m,j} - RW_{m,j}\right) \tag{30}$$

$$Spending_{m,t_d} = \sum_m \begin{cases} OMC_{m,j} & ; OMC_{m,j} \geq 0 \\ 0 & ; OMC_{m,j} < 0 \end{cases} \tag{31}$$

The algorithm used to determine the dividend is illustrated in Figure 9. In Equation (27), the dividend for a member is calculated based on the surplus that the cooperative makes and the member's contribution. During a period *td*, the surplus, as expressed in Equation (28), is the profit after deducting all expenses from the net return on investments. The contribution, as expressed in Equation (29), is based on each member's investment and total spending. The investment, as expressed in Equation (30), represents the shares and all future investment charges paid by each member until the end of the period. The shares can be purchased based on the total benchmark cost of the network that each member contributes to the local distribution system. The DisCo-op will evaluate the benchmark cost and register it as shares at the first opportunity after becoming a member. In Equation (31), the total spending is the payment for O and M from each member. It should be noted that the contribution is calculated only from positive payments in order to prevent negative contributions. Therefore, all negative amounts from rewards are excluded.

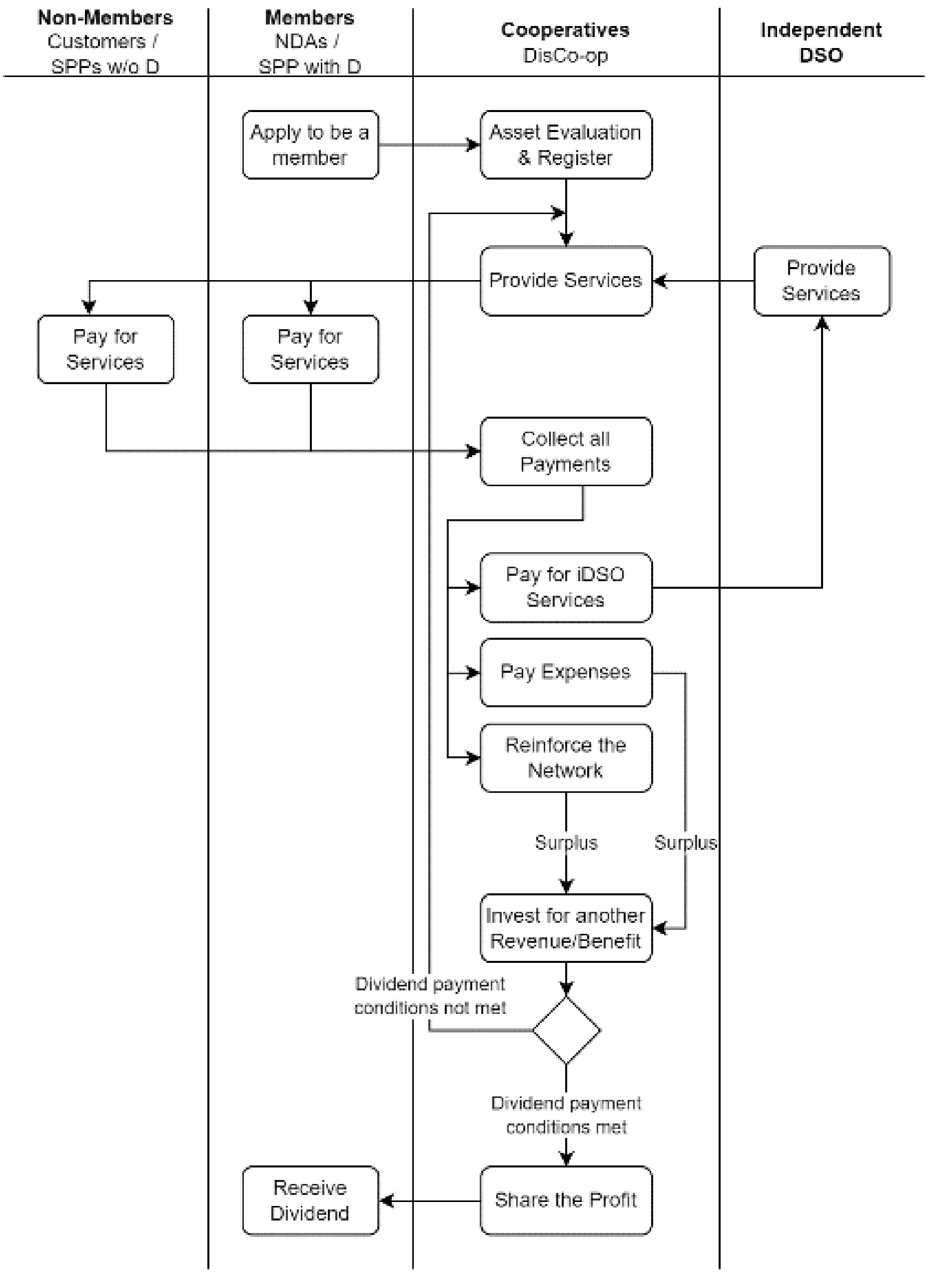

Figure 8. Operation of the proposed model under cooperative principles.

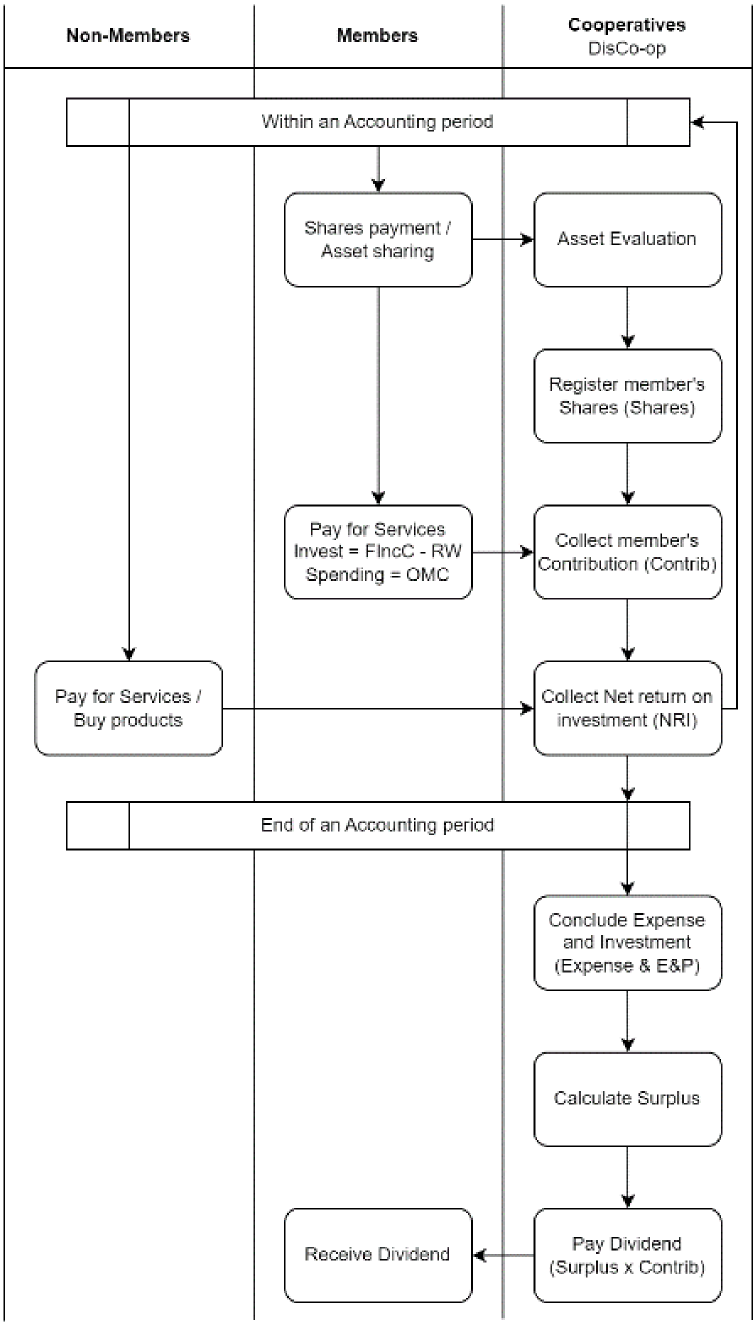

Figure 9. Dividend calculation algorithm.

4.6. When the NDA Is Unavailable

In areas where the NDA is unavailable, the same approach can still be applied. The DisCo-op can choose to play the role of the NDA if required; it can provide a reward or charge a penalty to the SPPs or customers and set the regulatory factor itself.

5. DUoSS: Numerical Example

5.1. Simulation on an Integrated Test System

To illustrate the calculation based on a test system that can represent the actual system, the IEEE 13 bus test feeder [44] was chosen to represent a local power market area. The system depicted in Figure 10 is an integrated distribution system assumed to consist of the NDS and the PDS area. The simulation was performed in two sample periods, i.e., peak and off-peak periods, similar to the previous example.

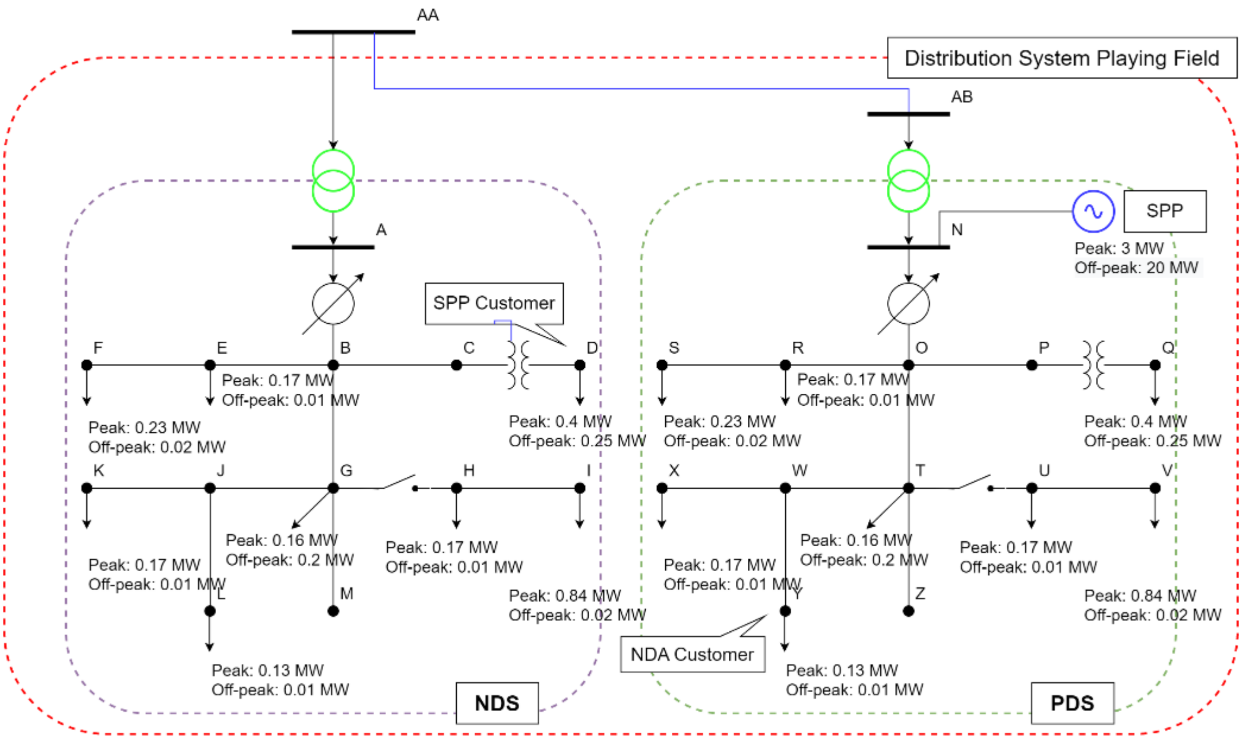

Figure 10. Integrated IEEE 13 bus test system in peak and off-peak periods.

The equivalent periodic cost (EPC) in the test system is assumed to be 990.00 GBP per half-day, as calculated from the equivalent monthly cost (EMC) of 62,400.00 GBP. The Y_i, EPC, and line capacity for each circuit in the test system, along with the regulatory factor and the defined period of calculation, are presented in Table 3.

Table 3. Integrated IEEE 13 bus test system's network cost.

Circuit	Y_i (GBP/kW/Period)	Safety Limit Capacity * (MW)	Maximum Capacity (MW)	EMC (GBP/Circuit)	EPC (GBP/Circuit)
AA-AB	0.01	16.00	20.00	3000.00	50.00
AA-A, AB-N	0.01	16.00	20.00	3000.00	50.00
A-B, N-O	0.01	16.00	20.00	3000.00	50.00
B-C, O-P	0.03	1.00	1.25	1800.00	30.00
C-D, P-Q	0.03	1.00	1.25	1800.00	30.00
B-E, O-R	0.03	1.00	1.25	1800.00	30.00
E-F, R-S	0.03	1.00	1.25	1800.00	30.00
B-G, O-T	0.01	16.00	20.00	3000.00	50.00
G-H, T-U	0.03	1.00	1.25	1800.00	30.00
H-I, U-V	0.03	1.00	1.25	1800.00	30.00
G-J, T-W	0.03	1.00	1.25	1800.00	30.00
J-K, W-X	0.03	1.00	1.25	1800.00	30.00
J-L, W-Y	0.03	1.00	1.25	1800.00	30.00
G-M, T-Z	0.01	16.00	20.00	3000.00	50.00
Total				62,400.00	990.00
Defined Period	Peak	9.00 a.m.–9.00 p.m.	Off-peak	9.00 p.m.–9.00 a.m.	
Regulatory factor	5%				

* Critical flows.

Table 4 also shows that customers have to pay a DUoSS charge of GBP 60.60 for network usage that exceeds the line capacity during peak periods, while the SPP does not need to pay due to its contribution during the peak period. Under the same approach, the

SPP has to pay 400.00 GBP for excess generation during the off-peak period when breaching the critical flows of lines AA-AB and AB-N. At the same time, the customers are rewarded with 10.60 GBP for their contributions during this period.

The DisCo-op can consider investing this money to reinforce the lines where safety capacity is often breached. Meanwhile, there is no charge for lines with usage below the safety limit, which means that the line capacity is sufficient for current usage and no reinforcement is required.

Table 5 shows the calculation of O and M cost based on the approach in Equations (18)–(26), where the utilisation factor ($\phi_{UTILISE}$) and the regulatory factor (ϕ_r) are set to unity (100%) and 0.05 (5%), respectively. It can be observed that, because of the unused lines, the total DUoSS charge for O and M collected from the user per period is only GBP 890.00, while the EPC is 990.00 GBP. This is an indicator of overinvestment. The DisCo-op is responsible for the cost of the unused lines.

Table 6 illustrates a summary of the responsibilities of each user in the integrated network. Every network user, including the SPP and the NDA, is responsible for the DUoSS charges. The customer charges are mainly derived from their actual electricity usage. The SPP charges come from the unused excess power generation. The charge for the NDA is a reward to the users who help reduce the network usage rating and the regulatory factors. Lastly, the cost of the unused parts of the network, along with any overinvestments, is the responsibility of DisCo-op.

The simulation was performed for one day only. Thus, the DUoSS charge was 2430.00 GBP (or 2230.00 GBP excluding the unused lines), as shown in Table 5. Therefore, if the same pattern in the simulation is repeated every day for a month (30 days), the accumulated charges would be 66,900.00 GBP.

After all DUoSS charges are collected from the users, the DisCo-op will make a regulatory payment to the NDA. However, if the regulatory factor is a negative value, the NDA will be billed for the DUoSS charges instead.

When considering the traditional wheeling approach, the NDA and the SPP will reciprocally charge one another for only the customer usage at Nodes D and Y. Table 7 shows wheeling charges for every user. During the off-peak period, the NDA network will use the entire power flow from the SPP network. Therefore, the NDA network usage rate will increase by 0.3090 GBP/kW as the wheeling rate from the SPP increases. On the other hand, during the peak period, the SPP network will use some of the power flows from the NDA network. In this case, it is about 0.27 MW. Therefore, the cost of SPP is increased by 0.0214 GBP/kW as a proportion of the NDA charge rate. This is even more complicated when more customers are on other networks, as illustrated in Figure 4.

This simulation demonstrates that DUoSS—a straightforward approach—can be used to determine the charges regardless of the network area. This not only eliminates the additional wheeling transactions but also ensures that the usage charges are based on the same approach for every user.

Based on the algorithm presented in Figure 9, Table 8 shows the dividend calculation against the contribution of each network user, which is accumulated into a total dividend for each cooperative member. It is assumed that the surplus made by the cooperative is 10,000.00 GBP and that the SPP and NDA hold the shares of the cooperative initiated from the value of the NDS and the PDS in the integrated system. In this simulation, the EPC is assumed to represent the shares instead of the actual initiated value of the NDS and the PDS, so that the contribution to the dividend will be observable. As shown in Table 7, the NDA receives a dividend of 4709.62 GBP, while the SPP receives a dividend of 5290.38 GBP. Both dividends are based on the investment and spending of each network user. Hence, the dividend is distributed fairly and equitably and complies with the patronage dividend concept.

Table 4. DUoSS charge calculation for network reinforcement for the integrated IEEE 13 bus test system.

Circuit	Service Provider	Power Flows (MW)		Critical Flows (MW)	Y_i (GBP/kW/ Period)	Cumulative Network Reinforcement Cost (GBP/kW)		Network Reinforcement Charges (GBP)		Total Charges (GBP)	Actual Cost (GBP)
		Peak	Off-Peak			Peak	Off-Peak	Peak	Off-Peak		
AA-AB	NDA	▼ 0.27	▲ 19.47	16.00	0.01	0.00	−0.01	0.00	0.00	0.00	194.70
AA-A	NDA	▼ 3.27	▼ 0.53	16.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
A-B	NDA	▼ 3.27	▼ 0.53	16.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
B-C	NDA	▼ 0.40	▼ 0.25	1.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00
B-E	NDA	▼ 0.40	▼ 0.03	1.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00
B-G	NDA	▼ 2.47	▼ 0.25	16.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
C-D	SPP	▼ 0.40	▼ 0.25	1.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00
E-F	NDA	▼ 0.23	▼ 0.02	1.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00
G-H	NDA	▼ 1.01	▼ 0.03	1.00	0.03	0.03	0.00	0.03 × 170 = 5.10	0.00	5.10	30.30
G-J	NDA	▼ 0.30	▼ 0.03	1.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00
G-M	NDA	-	-	16.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
H-I	NDA	▼ 0.84	▼ 0.02	1.00	0.03	0.00	0.00	0.03 × 840 = 25.20	0.00	25.20	0.00
J-K	NDA	▼ 0.17	▼ 0.01	1.00	0.03	0.03	0.00	0.00	0.00	0.00	0.00
J-L	NDA	▼ 0.13	▼ 0.01	1.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00
AB-N	SPP	▼ 0.27	▲ 19.47	16.00	0.01	0.00	−0.02	0.00	−0.02 × −2000 = 400.00	400.00	194.70
N-O	SPP	▼ 3.27	▼ 0.53	16.00	0.01	0.00	−0.02	0.00	0.00	0.00	0.00
O-P	SPP	▼ 0.40	▼ 0.25	1.00	0.03	0.00	−0.02	0.00	0.00	0.00	0.00
O-R	SPP	▼ 0.40	▼ 0.03	1.00	0.03	0.00	−0.02	0.00	−0.02 × 10 = −0.20	−0.20	0.00
O-T	SPP	▼ 2.47	▼ 0.25	16.00	0.01	0.00	−0.02	0.00	−0.02 × 200 = −4.00	−4.00	0.00
P-Q	SPP	▼ 0.40	▼ 0.25	1.00	0.03	0.00	−0.02	0.00	−0.02 × 250 = −5.00	−5.00	0.00
R-S	SPP	▼ 0.23	▼ 0.02	1.00	0.03	0.00	−0.02	0.00	−0.02 × 20 = −0.40	−0.40	0.00
T-U	SPP	▼ 1.01	▼ 0.03	1.00	0.03	0.03	−0.02	0.03 × 170 = 5.10	−0.02 × 10 = −0.20	4.90	30.30
T-W	SPP	▼ 0.30	▼ 0.03	1.00	0.03	0.00	−0.02	0.00	0.00	0.00	0.00
T-Z	SPP	-	-	16.00	0.01	0.00	−0.02	0.00	0.00	0.00	0.00
U-V	SPP	▼ 0.84	▼ 0.02	1.00	0.03	0.00	−0.02	0.03 × 840 = 25.20	−0.02 × 20 = −0.40	24.80	0.00
W-X	SPP	▼ 0.17	▼ 0.01	1.00	0.03	0.03	−0.02	0.00	−0.02 × 10 = −0.20	−0.20	0.00
W-Y	NDA	▼ 0.13	▼ 0.01	1.00	0.03	0.00	−0.02	0.00	−0.02 × 10 = −0.20	−0.20	0.00
Total								60.60	389.40	450.00	450.00
Equalisation										0.00	
Accumulative Charges										450.00	450.00

* ▼ Power Flows by current. ▲ Power Flows against current.

Table 5. DUoSS calculation for O and M for the integrated IEEE 13 bus test system.

Circuit	EPC (GBP) $\Phi_{UTILISE} = 1$	Line Capacity (MW)	Rate (W_n^{om}) (GBP/kW)	Sharing Factor (F)	
				Peak	Off-Peak
AA-AB	50.00	20.00	0.0026	74.0741	1.0272
AA-A	50.00	20.00	0.0026	6.1162	37.7358
A-B	50.00	20.00	0.0026	6.1162	37.7358
B-C	30.00	1.25	0.0252	3.1250	5.0000
B-E	30.00	1.25	0.0252	3.1250	41.6667
B-G	50.00	20.00	0.0026	8.0972	80.0000
C-D	30.00	1.25	0.0252	3.1250	5.0000
E-F	30.00	1.25	0.0252	5.4348	62.5000
G-H	30.00	1.25	0.0252	1.2376	41.6667
G-J	30.00	1.25	0.0252	4.1667	62.5000
G-M	50.00	20.00	0.0026	N/A	N/A
H-I	30.00	1.25	0.0252	1.4881	62.5000
J-K	30.00	1.25	0.0252	7.3529	125.0000
J-L	30.00	1.25	0.0252	9.6154	125.0000
AB-N	50.00	20.00	0.0026	74.0741	1.0272
N-O	50.00	20.00	0.0026	6.1162	37.7358
O-P	30.00	1.25	0.0252	3.1250	5.0000
O-R	30.00	1.25	0.0252	3.1250	41.6667
O-T	50.00	20.00	0.0026	8.0972	80.0000
P-Q	30.00	1.25	0.0252	3.1250	5.0000
R-S	30.00	1.25	0.0252	5.4348	62.5000
T-U	30.00	1.25	0.0252	1.2376	41.6667
T-W	30.00	1.25	0.0252	4.1667	62.5000
T-Z	50.00	20.00	0.0026	N/A	N/A
U-V	30.00	1.25	0.0252	1.4881	62.5000
W-X	30.00	1.25	0.0252	7.3529	125.0000
W-Y	30.00	1.25	0.0252	9.6154	125.0000
Total	990.00				
User	**Total Usages (MW)**		**Charges (GBP)**		**Total (GBP)**
	Peak	**Off-Peak**	**Peak**	**Off-Peak**	
AA (NDA)	$\phi_r = 0.05$	−44.50	−44.50	−89.00	
D	1.6000	1.5000	75.84	113.88	189.72
E	0.5100	0.0500	18.84	12.53	31.38
F	0.9200	0.1200	57.00	56.57	113.57
G	3.4800	1.0000	61.90	82.70	144.61
H	0.6800	0.0600	14.37	14.64	29.01
I	4.2000	0.1400	102.53	60.77	163.30
K	0.8500	0.0700	58.42	51.39	109.81
L	0.6500	0.0700	52.10	51.39	103.47
N (DER)	0.0000	37.8800	0.00	102.14	102.14
Q	1.2661	0.7500	82.27	87.76	170.03
R	0.3681	0.0200	21.58	11.49	33.07
S	0.7280	0.0600	60.69	54.48	115.17
T	2.5116	0.4000	80.53	61.81	142.34
U	0.5381	0.0300	17.10	13.59	30.69
V	3.4987	0.0800	116.01	58.68	174.69
X	0.7081	0.0400	61.15	50.34	111.49
Y	0.5415	0.0400	54.18	50.34	104.52
Unused Circuits (DisCo-op)			100.00	100.00	200.00
Total			990.00	990.00	1980.00

Table 6. Total DUoSS charge summary for the integrated IEEE 13 bus test system.

User	Service Provider	FInvC (GBP)	Reward (GBP)	O&M (GBP)	Total DUoSS (GBP)
E	NDA	0.0000	0.0000	31.3813	31.3813
F	NDA	0.0000	0.0000	113.5679	113.5679
G	NDA	0.0000	0.0000	144.6048	144.6048
H	NDA	5.1000	0.0000	29.0091	34.1091
I	NDA	25.2000	0.0000	163.2949	188.4949
K	NDA	0.0000	0.0000	109.8071	109.8071
L	NDA	0.0000	0.0000	103.4725	103.4725
Y	NDA	0.0000	−0.2000	104.5152	104.3152
Total—NDA Customer		30.3000	−0.2000	799.6528	829.7528
D	SPP	0.0000	0.0000	189.7206	189.7206
Q	SPP	0.0000	−5.0000	170.0302	165.0302
R	SPP	0.0000	−0.2000	33.0661	32.8661
S	SPP	0.0000	−0.4000	115.1716	114.7716
T	SPP	0.0000	-4.0000	142.3388	138.3388
U	SPP	5.1000	−0.2000	30.6940	35.594
V	SPP	25.2000	−0.4000	174.6921	199.4921
X	SPP	0.0000	−0.2000	111.4920	111.292
Total—SPP Customer		30.3000	−10.4000	967.2054	987.1054
Regulatory Payment—NDA				−89.0000	−89.0000
Unused Lines—DisCo-op				200.0000	200.0000
Total		400.0000	−10.6000	1980.0000	2430.0000

Table 7. Wheeling approach simulation for the integrated IEEE 13 bus test system.

User	Service Provider	Postage Stamp Rate (GBP/kW)		Power Flows (MW)		Network Usage Charges (GBP)		Total (GBP)
		Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	
E	NDA	0.2804	0.2804 + 0.3090	0.17	0.01	47.6764	5.8949	53.5713
F	NDA	0.2804	0.2804 + 0.3090	0.23	0.02	64.5034	11.7898	76.2932
G	NDA	0.2804	0.2804 + 0.3090	1.16	0.2	325.3213	117.8981	443.2195
H	NDA	0.2804	0.2804 + 0.3090	0.17	0.01	47.6764	5.8949	53.5713
I	NDA	0.2804	0.2804 + 0.3090	0.84	0.02	235.5775	11.7898	247.3673
K	NDA	0.2804	0.2804 + 0.3090	0.17	0.01	47.6764	5.8949	53.5713
L	NDA	0.2804	0.2804 + 0.3090	0.13	0.01	36.4584	5.8949	42.3533
Y	SPP	0.3090 + 0.0214	0.3090	0.13	0.01	42.9561	3.0904	46.0465
Total—NDA Customer						887.4977	168.1478	1055.6455
D	NDA	0.2804	0.2804 + 0.3090	0.40	0.25	112.1798	82.6078	194.7876
Q	SPP	0.3090 + 0.0214	0.3090	0.40	0.25	132.1725	3.0904	209.4328
R	SPP	0.3090 + 0.0214	0.3090	0.17	0.01	56.1733	6.1808	59.2637
S	SPP	0.3090 + 0.0214	0.3090	0.23	0.02	75.9992	61.8082	82.1800
T	SPP	0.3090 + 0.0214	0.3090	1.16	0.2	383.3003	3.0904	445.1085
U	SPP	0.3090 + 0.0214	0.3090	0.17	0.01	56.1733	6.1808	59.2637
V	SPP	0.3090 + 0.0214	0.3090	0.84	0.02	277.5623	3.0904	283.7431
X	SPP	0.3090 + 0.0214	0.3090	0.17	0.01	56.1733	3.0904	59.2637
Total—SPP Customer						1149.7341	203.6574	1353.3915
Total						2037.2318	371.8052	2409.0370

5.2. Simulation of the PEA's Distribution System: Amata City Industrial Estate

Figure 11 depicts a part of the existing distribution system at the Amata City Industrial Estate under Thailand's Provincial Electricity Authority (PEA); it illustrates many possibilities to tie SPP distribution lines to the PEA network from the PEA's point of view. One of the best possibilities is to use a substation at a high-voltage (HV) level.

Table 8. Dividends for each member.

Network User	Shares (GBP)	FInvC (GBP)	O&M (GBP)	Contribution	Dividend (GBP)
Surplus	10,000.00				
E		0.0000	31.5622		
F		0.0000	113.9299		
G		0.0000	148.2242		
H		5.1000	29.1901		
I		25.2000	163.6568		
K		0.0000	109.9881		
L		0.0000	103.6535		
Y		0.0000	104.5152		
NDA		0.0000	0.0000		
Total	540.00	30.3000	804.7200	0.4710	4709.62
D		0.0000	194.2448		
Q		0.0000	170.0302		
R		0.0000	33.0661		
S		0.0000	115.1716		
T		0.0000	142.3388		
U		5.1000	35.794		
V		25.2000	199.8921		
X		0.0000	111.492		
SPP		0.0000	194.2448		
Total	450.00	30.3000	1064.2800	0.5290	5290.38
Grand Total	990.00	60.6000	1869.0000	1.0000	10,000.00

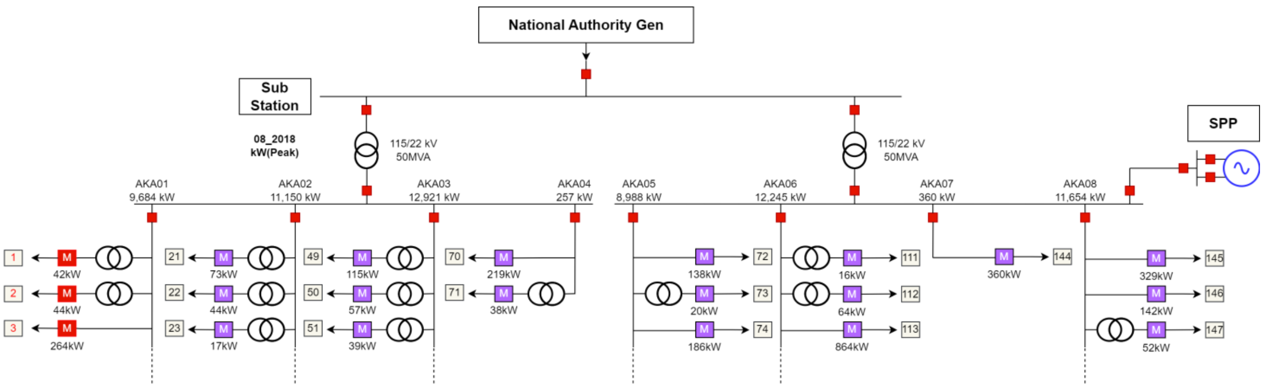

Figure 11. A part of the distribution system of the Amata City Industrial Estate under Thailand's Provincial Electricity Authority (PEA).

Based on the report from the PEA in [3] on the wheeling charge rate for the SPPs, Figure 12 and Table 9 illustrate the summary of the actual data from the Amata City Industrial Estate in August 2018. The input data in the PEA report indicate that the network is always in a normal condition, without any signals for network reinforcement. The defined maximum capacity (DMC) of the PEA for the Amata City Industrial Estate is 410.40 MW. The defined load for customers is 277.00 MW, although the total actual usage of the system is only 66.26 MW. This simulation assumes that all customers in the AKA01 section (the red section in Figure 11) belong to the SPP. This means that the SPP will inject only 9.68 MW into the system, leaving 344.14 MW (i.e., 84% of the network capacity) unused.

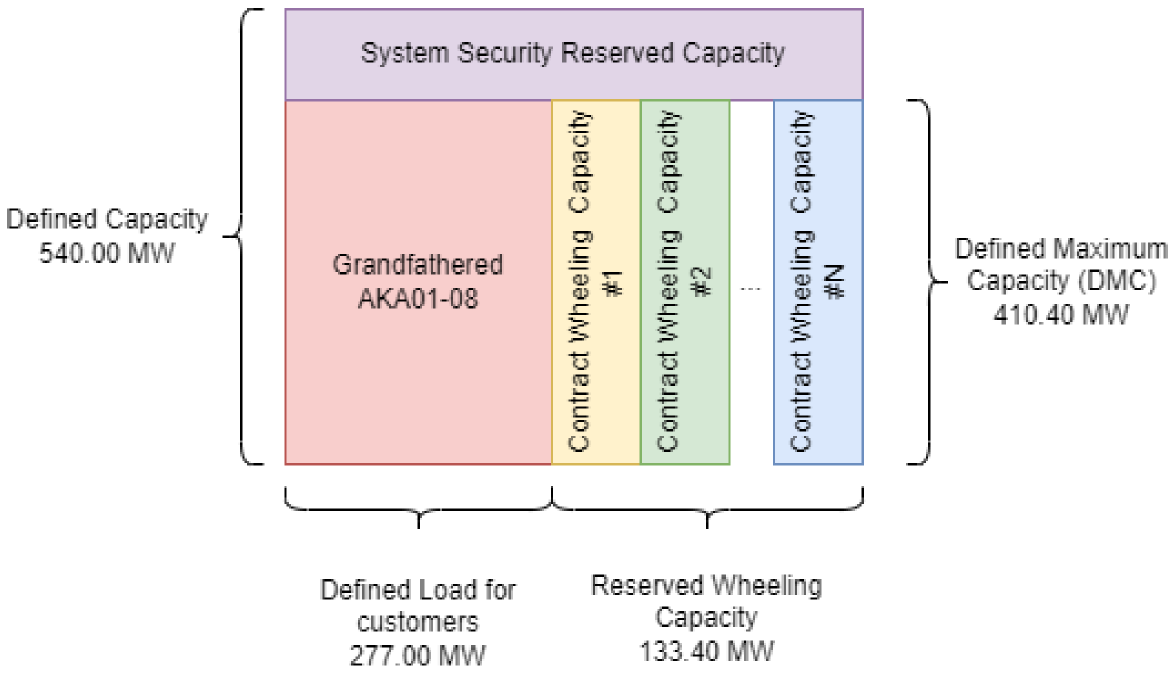

Figure 12. Grandfathered concept of the distribution system of the Amata City Industrial Estate from Thailand's Provincial Electricity Authority (PEA).

Table 9. System parameters of the Amata City Industrial Estate from [3] (August 2018).

System Load Parameters for Wheeling Charge Calculation			
Designed Capacity (kW)			540,000.00
Defined Maximum Capacity (DMC) (kW)			410,400.00
Defined Load for Customers (kW)			277,000.00
Reserved Wheeling Capacity (kW)			133,400.00
Contract Wheeling Capacity (kW)			-
Feeder	**MV—Maximum Demand (kW)**	**Feeder**	**MV—Maximum Demand (kW)**
AKA01	9683.65	AKA05	8988.05
AKA02	11,150.27	AKA06	11,244.88
AKA03	12,921.05	AKA07	360.00
AKA04	257.20	AKA08	11,653.98
Total		66,259.08	

In [3], two new methodologies were proposed for the PEA that can be applied to any industrial estate area instead of using the national rate: the postage stamp method and a method proposed by Thammasat University (the TU cost-based method). These methods proposed the wheeling rate for the Amata City Industrial Estate at 58.76 THB/kW/month and 61.69 THB/kW/month, respectively. In [19], the distribution usage uniform tariff (D) of the PEA was defined at 132.93 THB/kW/month.

Table 10 illustrates the comparison between the DUoSS charge and other wheeling charge methods in the PEA report for the Amata City Industrial Estate. The table shows that, due to ineffective network utilisation, none of the methods in the PEA report can recover the costs of the distribution system in the Amata City Industrial Estate. Therefore, this cost has to be subsidised by the PEA.

Table 10. Cost recovery comparison between the study results in the PEA's report [3] and the DisCo-op DUoSS charge when the network is used at ~16% utilisation.

Method	PEA's Contribution ϕ_r = 5% (THB '000)	SPP and SPP's Customers (THB '000)	PEA's Customers (THB '000)	Total (THB '000)	Actual Cost (THB '000 per Month)
TOU Tariff	-	1287.25	7520.57	8807.82	24,113.30
Postage Stamp	-	568.97	3324.12	3893.09	24,113.30
TU Cost-Based	−194.65	597.42	3490.33	3893.09	24,113.30
DisCo-op DUoSS—Monthly					
$\phi_{UTILISE}$ = 1	−1205.67	2820.35	22,498.62	24,113.30	24,113.30
$\phi_{UTILISE}$ = 0.16	−194.66	455.35	3632.40	3893.09	3893.09
Network Usage Rate = Actual Use/DMC = 66.26/410.40 = 0.16					

The table also shows that the DUoSS charge always guarantees cost recovery. Therefore, the charges for SPPs and their customers are higher than those in other methods when the network is only ~16% utilised. The DUoSS charge can give almost the same rate as the TU cost-based method if the DisCo-op sets the utilisation factor to the rate of network usage, i.e., 0.16 or 16%. However, this means that the DisCo-op will subsidise the other 84% of the cost.

Table 11 illustrates the charges when the network is simulated at ~80% utilisation (i.e., five times the current usage). When the distribution system is more effectively utilised without any critical flows being breached, and with the same usage ratios, the DUoSS charge rate is cheaper, and the total charges remain the same as when the network is only 16% utilised. This property can be used as a signal to make both the customers and the DisCo-op aware of the network utilisation, as well as to indicate plans for future network reinforcement.

Table 11. Cost recovery comparison between the study results in the PEA's report [3] and the DisCo-op DUoSS charge when the network is simulated at ~80% utilisation.

Method	PEA's Contribution ϕ_r = 5% (THB '000)	SPP and SPP's Customers (THB '000)	PEA's Customers (THB '000)	Total (THB '000)	Actual Cost (THB '000 per Month)
TOU Tariff	-	6436.24	37,602.86	44,039.10	24,113.30
Postage Stamp	-	2844.84	16,620.62	19,465.46	24,113.30
TU Cost-Based	−973.27	2987.09	17,451.65	19,465.46	24,113.30
DUoSS—Monthly					
$\phi_{UTILISE}$ = 1	−1205.67	2820.35	22,498.62	24,113.30	24,113.30
$\phi_{UTILISE}$ = 0.81	−973.27	2276.73	18,162.01	19,465.46	19,465.46
Network Usage Rate = Actual Use/DMC = (66.26 × 5)/410.40 = 0.81					

As mentioned in Section 1, the results in Tables 10 and 11 confirm that the distribution usage charges (D) in the uniform tariff (UT) cannot guarantee the cost recovery of a local system. In Table 10, the charge is less than the actual cost. Meanwhile, the charge from the tariff exceeds the actual cost even though the network is still not fully utilised, as shown in Table 11.

It is noted that, from the study data which is obtained from the PEA report as shown in Table 10, the utilisation rate of the network in the Amata City Industrial Estate is about 16%. This data is used to scale up the simulation in other cases and to observe when the network is fully utilised, as illustrated in Table 11. It is found that when the usage rate is above 80%, the safety limit of some parts of the network is breached, which causes an additional cost for network reinforcement. To prevent confusion, it is worth keeping the cost components of both scenarios on the same page. Therefore, the simulation between the network is ~16% utilised, and ~80% utilised is chosen for comparison.

In the postage stamp, TU cost-based, and national rate methods, the information of each customer's usage is absent because the charges are only designed for the SPPs. Therefore, the SPPs have to distribute the charges to their customers themselves. With the DUoSS charge, every usage detail is traceable. The usage pattern and the pricing signal for individual users, including the SPP, can be captured. The charge for future investment can be calculated and sent to related users fairly and equitably. The user behaviour data are also a good source for extensive data analysis in the future.

6. Comparison between the DisCo-Op Model and the Traditional Wheeling Model

This paper introduces DisCo-op—a novel distribution system management model based on the concept of the cooperative—to manage a combined, single, multi-owned distribution system. The core issue is resolving the multiple ownership problems in overlapping areas, ensuring cooperation amongst distribution owners and eliminating the complexity of the wheeling model and investment redundancy. This issue is relevant to almost all countries with similar power sector structures. Table 12 presents a comparison between the DisCo-op model, the multi-owned distribution system when each network is physically separated (Figure 2) and the integrated distribution system with a traditional wheeling model (Figure 3).

Table 12. Comparison between the DisCo-op model and the multiple ownership wheeling model.

Topic	DisCo-op Model	Multi-Owned Distribution System When Each Network Is Physically Separated	Integrated Distribution System with a Traditional Wheeling Model
1. Economic Efficiency			
- Network expansion and planning - Redundancy network construction prevention	Best	Worst	Moderate
2. Network Operation			
- Easy to operate the network	Moderate	Best	Moderate
3. Network Reinforcement			
- Network reliability - Defer investment to the right time	Best	Moderate	Moderate
4. Non-Discrimination	Best	N/A	Worst
5. Easy to Understand	Moderate	Best	Worst
6. Competition in Generations	Best	Worst	Moderate
7. Benefit to the Network Owners			
- Profit sharing	Best	N/A	Worst
- Simple network management scheme	Moderate	Best	Worst

Regarding economic efficiency, the comparison is made based on network expansion, planning, and a chance of redundancy in network construction. Therefore, the DisCo-op is the best way when compared to the others because it unites the direction of network expansion and the planning of the entire network.

From the network operation point of view, the independent network is the easiest way to operate. However, in the DisCo-op model, the iDSO is established to help operate the network.

Regarding network investment and reinforcement, the DUoSS can guarantee deferring the investment to the right time, while the reinforcement in another model depends only on the network owner's decision.

Regarding the network users, the DisCo-op treats every network user without discrimination. Every user will be charged according to their actual usage.

The DUoSS is designed with the ability to calculate by using a simple spreadsheet. As a result, the customers can quickly understand their usage charges, rewards and penalties in a period with little understanding of engineering and financial terms, such as power flow analysis, network benchmark cost or related factors. It differs from the wheeling model, which may require a complicated explanation, as mentioned in Figure 4.

The DisCo-op model opens up competition on generation. The DisCo-op will be a single juristic person for the distribution network, where the new players can compete with others with the same rules and regulations as the other.

For the network owners themselves, the core principle of the DisCo-op is profit sharing from mutual benefit. However, unlike the separated and integrated networks with wheeling charges, the profit is from the sole business.

Regarding network management, it is obvious that the separated network is the most straightforward model for managing. However, the DisCo-op model is designed to manage the network as simply as possible through the cooperatives and iDSO.

7. Conclusions

When the DisCo-op model is adopted, the SPPs and NDAs can cooperate for their mutual benefit. Due to the unique character of the cooperative, the voting rights of each member are equal in order to ensure a balance of power and secure the system. Meanwhile, the net profit of the DisCo-op is returned to each member in the form of dividends. The cooperative treats all of its members fairly and equitably and distributes benefits based on their contributions.

Under the proposed model, a straightforward approach for determining the DUoSS charges between grid owners and customers is introduced to replace the existing complicated wheeling charge calculations. When testing the model, the results showed that this approach can create a fair scenario because it is calculated based on the actual usage of every network user.

To describe the fair scenario, in the numerical example for Amata City Industrial Estate, the amount of the total charge will always recover the actual cost for any usage rating, regardless of the subsidisation. Moreover, the numerical example for the integrated IEEE test system ensures that the proportion of the network cost is distributed to each user fairly, depending on the actual network usage.

Furthermore, once the distribution networks have become a single system, it is possible to identify congested lines that breach their safety capacity as well as the unused lines in the entire network. Therefore, overinvestment can be avoided by utilising this information.

Finally, due to the key components of the DUoSS charge (i.e., for O and M and future investment), all essential costs are already covered in the charge rate. Therefore, this approach can guarantee that the network will always have sufficient funds to maintain and continuously develop its infrastructure.

It should be noted that the proposed DUoSS methodology possesses a plug-and-play feature. As long as the business model and profit-sharing persist, the future investment and O and M charges in the DUoSS charge can be replaced with other, more suitable methodologies depending on each circumstance and requirement in a local context.

Instead of the redundancy of distribution system investment amongst many network owners—i.e., the SPPs and NDAs—especially in overlapping areas, they can form business alliances to obtain mutual benefit and improve economic efficiency. Moreover, their cooperation can improve the distribution system, making it highly reliable and sustainable.

Author Contributions: Project administration, methodology, software, validation, formal analysis, resources, data curation, writing—original draft preparation, visualization, funding acquisition, P.C.; conceptualization, methodology, validation, formal analysis, verification, investigation, resources, writing—review and editing, supervision, N.L. All authors have read and agreed to the published version of the manuscript.

Funding: The research leading to this study has received funding from the Faculty of Engineering at Thammasat University under grant agreement No 01/2559.

Data Availability Statement: Not applicable.

Acknowledgments: Financial support granted by the faculty of engineering at Thammasat University is greatly appreciated and acknowledged.

Conflicts of Interest: The authors declare no conflict of interest.

Abbreviations

D	Distribution usage charge in UT
D_L	Distribution usage charge for local system
DisCo-op	Distribution cooperative
DSO	Distribution system operator
DUoSS	Distribution use-of-sharing-system charge, expressed in GBP
E and P	Expansion and planning
iDSO	Independent distribution system operator
NRI	Net return on investment
MWh	Megawatt hours
NDA	National distribution authority
NDS	National distribution system
NRI	Net return on investment
O and M	Operation and maintenance
PDS	Private distribution system
SPP	Small power producer
T	Transmission usage charge in UT
UT	Uniform tariff
Indices	
i	Network user i in distribution system
j	DUoSS calculation period in period t_d
k	Network user $k \in \{a, p, c\}$a = national distribution authority (NDA) p = small power producer (SPP) c = customer
m	DisCo-op's member m
n	Distribution line n of the playing field
t	DUoSS calculation period
t_d	Dividend calculation period
Parameters	
y_n	Benchmark future network reinforcement rate of line n (GBP/kW)
f_n^{cf}	Critical flow of line n (kW)
ϕ_r	NDA's regulatory factor
$\phi_{UTILISE}$	DisCo-op's utilisation factor
f_n^{cap}	Maximum capacity of line n (MW)
EPC_n	Actual network operation and maintenance equivalent periodic cost of line n (GBP)
$Shares_{i,t_d}$	Number of shares held by member i at period t_d (GBP)
Variables	
$FInvC_t$	Future network reinforcement cost calculated for period t (GBP)
OMC_t	Operation and maintenance cost of the existing network calculated for period t (GBP)
Eq	Equalisation cost to balance actual cost and calculated cost (GBP)
$FInvC_k$	Future network reinforcement cost for user k (GBP)
OMC_k	Operation and maintenance cost for user k (GBP)
Eq_k	Equalisation cost for user k (GBP)
Y_i	Benchmark future network reinforcement rate at circuit i (GBP/kW)
$PG_{i,k}^{off-peak}$	Power flow from user k's generation in circuit i in the off-peak period (kW)
$PD_{i,k}^{peak}$	Power flow for user k's demand in circuit i in the peak period (kW)
$RW_{i,p}$	Monetary reward for network contribution for the SPP for circuit i (GBP)
$RW_{i,c}$	Monetary reward for network contribution for the customers for circuit i (GBP)
f_n^a	Actual flows of line n (kW)
f_n^d	Power flow caused by demand in line n (kW)
f_n^g	Power flow caused by generation in line n (kW)
EPC_n^{om}	Network operation and maintenance equivalent periodic cost of line n (GBP)
F_n	Sharing factor of line n

W_n^{om}	Operation and maintenance charge rate of line n (GBP/kW)
$f_{n,k}$	Power flows in line n that belong to user k (MW)
$Surplus_{t_d}$	The surplus of the cooperative for period t_d (GBP)
$Expense_{t_d}$	Actual O and M expenses for period t_d (GBP)
$Income_{t_d}$	Actual income collected from DUoSS for period t_d (GBP)
$E\&P_{t_d}$	Actual saving reserved for future expansion and planning for period t_d (GBP)
Div_{m,t_d}	Dividend for member m for period t_d (GBP)
$Contrib_{m,t_d}$	Contribution of member m for period t_d (GBP)
$Invest_{m,t_d}$	Amount of investment from member m for period t_d (GBP)
$Spend_{m,t_d}$	Spending of member m for period t_d (GBP)
$FInvC_{m,j}$	Future network reinforcement charge paid by member m for period j (GBP)
$RW_{m,j}$	Reward received by member m for period j (GBP)
$OMC_{m,j}$	Charge for network operation and maintenance paid by member m for period j (GBP)

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