IET Research Journals

A DSO-TSO balancing market coordination scheme for the decentralised energy future

ISSN 1751-8644
doi: 0000000000
www.ietdl.org

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Abstract: The proliferation of distributed generation and the electrification of heat and transport pose significant challenges to distribution system operators (DSOs), and transmission system operators (TSOs). These challenges include the choice between network upgrades or operating increasingly constrained networks, with a reliance on the flexibility of distributed energy resources (DERs). This paper presents a novel market based coordination scheme, which allows both the DSO and TSO to access DER flexibility, while respecting distribution system limits. The DSO's objective in this work is to minimise the cost incurred by DSO adjustments to DERs, required to ensure stable distribution network operation. The methodology presented has the advantages of being compatible with existing TSO balancing market operation, and scalable enough to include multiple DSO markets coordinating with the TSO. The approach is demonstrated on a section of GB distribution network, using high DER growth scenario data for the year 2030. The case studies demonstrate the proposed DSO market mechanism to maintain thermal and voltage limits during periods of peak demand and DER output. The DSO is given priority in using DERs to solve distribution network constraints, however, significant flexibility remains for the TSO even during periods of peak demand and maximum export.

Nomenclature

Sets

$\mathcal{D}$	set of demands
$\mathcal{G}$	set of Distributed Energy Resources (DERs)
$\mathcal{L}$	set of lines
$\mathcal{B}$	set of buses

Indices

d	demand
g	DER
b	bus
LB, UB	lower bound, upper bound
L	line
T	transmission
bb'	from bus b to b'

Parameters

P, Q	active, reactive power set points
$\mathrm{C}^{\downarrow}$, $\mathrm{C}^{\uparrow}$	cost to turn down, turn up
V	Value of lost load
G	line conductance
B	line susceptance
S	apparent power
P^T	transmission import/export

Variables

p, q	active, reactive power dispatch
$p^{\downarrow}$, $p^{\uparrow}$	downward, upward re-dispatch from DER set-point
v	voltage
θ	voltage angle
p^{D}	demand delivered

Acronyms

ACOPF, AC Optimal Power Flow; ANM, Active Network Management; BM, Balancing Mechanism; BRP, Balancing Responsible Party; BSP, Bulk Supply Point; CR, Community Renewables; EV, Electric Vehicle; DER, Distributed Energy Resource; DG, Distributed Generation; DSR, Demand Side Response; FES, Future Energy Scenarios; GB, Great Britain; GSP, Grid Supply Point; NLP, Non-linear Programming; STOR, Short Term Operating Reserve; TSO, Transmission System Operator; T&D, Transmission & Distribution; WPD, Western Power Distribution.

1 Introduction

Distributed Energy Resources (DERs), including PV, wind, CHP, biomass, energy storage systems and Electric Vehicle (EVs), will play a key role in the decarbonisation of the electricity supply. It is anticipated that up to 45% of total generation capacity in Great Britain (GB) will be connected within distribution networks by 2030 [1]. In recent years, aggregators have taken an increasing role in accessing the flexibility of DERs, including offering ancillary services (e.g. Short Term Operating Reserve and Firm Frequency Response) to the Transmission System Operator (TSO) [2]. In addition, aggregators entered the GB balancing mechanism, in August 2018, with accepted balancing volumes rising steadily since (see Figure 1).

As the capacity of DERs increases in constrained areas of network, system limits (e.g. thermal, voltage and fault current) could become a barrier to the amount of flexibility offered by DERs. Active network management (ANM) schemes are a first step towards managing associated network constraints, however, generators may be discouraged by uncertain return on their investments if they enter a non-firm ANM contract [4, 5]. Market based ANM schemes have been proposed [6] as a solution to improve investment certainty, but still lack adequate coordination with the TSO.

Distribution System Operator (DSO) markets have been proposed [7], and are being trialled [8], as a method of managing distribution constraints. DSO markets can be for the procurement of flexibility or ancillary services at distribution level, which could include a region, a grid supply point or a section of distribution network. The DSO market provides a mechanism to reward DERs for providing flexibility to relieve distribution system constraints, and will improve incentives for investment in DERs. DSO markets can be considered an evolution of current ANM schemes by adding a market layer

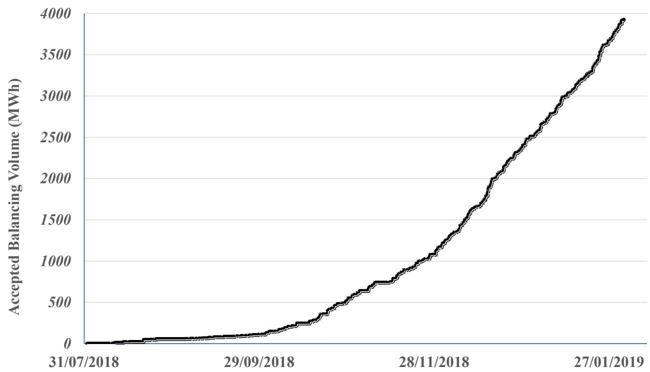

Fig. 1: Cumulative accepted balancing volumes of select aggregator balancing mechanism units (BMUs), August 2018 to January 2019; data: [3]

to the ANM's control layer. Figure 2 illustrates the transition from passive networks, via ANM schemes, to DSO markets with the corresponding increases in capacity limits, metering/communication, modelling complexity, and levels of DSO-TSO coordination. These increases would incur a cost which would be compared to traditional network reinforcement (and passive network operation). The cost-benefit of ANM has been proven during trials [9, 10], and has since been widely applied to constrained regions of GB distribution networks. The cost-benefit of DSO markets, with some of the additional requirements shown in Figure 2, is being assessed in trials taking place across GB (e.g. [8] [11]).

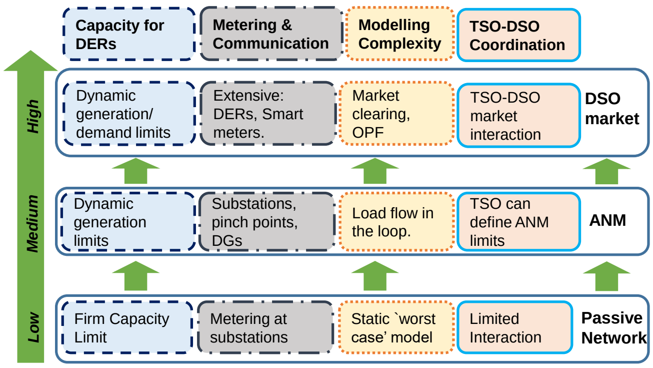

Fig. 2: The evolution from passive distribution networks and ANM to DSO markets. The DSO-TSO coordination scheme proposed, provides a tool in the transition from passive networks to the DSO market place, which would enhance utilisation of DERs.

Although DSO trials are taking place in GB, it is not yet clear how access to DERs will be coordinated between the DSO and TSO. It is widely accepted that there is a need for coordination between transmission and distribution (T&D) markets, to give the most efficient use of DERs, and to prevent conflict between the TSO's and DSO's objectives [4, 12, 13]. The problem of TSO-DSO interaction is an active area of research and the existing literature is compared in detail with the authors approach in Section 2. Models have been proposed for TSO-DSO coordination [13–15], however there is limited demonstration on test networks to validate them. The timescales and interactions for DSO and TSO markets hav not been established and a viable method is yet to be demonstrated based on any detailed modelling. This paper builds on the existing literature by demonstrating a framework for DSO markets to coordinate with the existing TSO balancing markets. In this work, consideration has been given to the scheduling of DSO and TSO markets, specifically the DSO market running ahead of the TSO market, which has not been considered in literature to date. Detailed studies have been carried out on a section of GB distribution network.

The proposed method fits broadly into the 'common DSO-TSO market' model from [13]. It has the advantage over the DSO providing prequalification for a centralised TSO market, in that dynamic compensation for DERs, which are limited in their participation in the TSO market as a result of distribution network constraints, is provided. It also has advantages over the local market model as the DSO does not need to aggregate DERs. A disadvantage with the proposed method could be that conservative limits could be required by the DSO to run a market an hour ahead of the TSO, and two hours ahead of delivery, due to uncertainty over output from DERs. To address this uncertainty, probabilistic methods could be employed to ensure that the DSO maintains network stability for a range of possible input scenarios.

The German Association of Energy and Water Industries' 'traffic light' concept [16], provides a framework for DSO-TSO coordination. In the 'green' state of the traffic light concept, DERs can participate directly in the TSO market, in the 'amber' state, a DSO marketplace resolves constraints, and in the 'red' state, the DSO intervenes directly to prevent violations. The main contribution of this paper is the novel implementation of a DSO-TSO balancing market coordination model, to resolve the 'amber' state in the traffic light concept.

The DSO-TSO balancing market coordination model proposed in this paper, is demonstrated on a constrained distribution network in GB, under a future high DER growth scenario. The objective of the market coordination is to achieve the most efficient dispatch of DERs (e.g. PV, Wind, EVs and batteries) to minimise system costs (balancing and reinforcement) at both distribution and transmission level.

The model has the advantage of being compatible with existing transmission balancing markets, without the need for a complete system redesign. The existing GB transmission level balancing mechanism operates from 1 hour ahead of delivery (known as 'gate closure'), when the TSO takes bids and offers from all participants to adjust output. The TSO takes redispatch actions, which are paid as bid, to balance supply and demand and to relieve transmission constraints. In the proposed coordination scheme, the DSO market will clear ahead of the TSO market and provide adjusted DER limts and set points to the TSO at gate closure.

In the authors' implementation, the DSO balancing market is used to solve distribution congestion, while setting limits to participation of DERs in the TSO balancing market. This ensures that instructions to DERs from the TSO do not violate constraints (e.g. exceeding thermal and voltage limits) at distribution. To integrate the proposed coordination model, there is no requirement for major changes to existing TSO balancing market operation. The main possible effect could be an increase in the number of DER participants, with a resultant computational burden placed on the TSO.

To deal with the growing number of smaller DERs participating in the GB balancing mechanism, the TSO (National Grid) added a distributed resource desk in January 2019. Historically, the TSO passed bid/offer acceptance instructions manually, tending to favour larger units that can provide flexibility with a minimum number of instructions. Increased use of automation and optimisation techniques will likely be required by the TSO to access flexibility from an increasing number of DERs.

As far as possible, real demand, price and generation data has been used in simulations, to more accurately predict the requirement of the DSO and TSO for flexibility. The work reported here goes beyond the existing literature by giving results of DSO-TSO interaction, and shows how the sharing of flexibility between DSO and TSO can be coordinated.

The remainder of the paper is structured as follows: Section 2 reviews the state of the art in DSO-TSO coordination, Section 3 outlines the DSO-TSO balancing market coordination model proposed in this work, Section 4 describes case studies used to demonstrate the model, Section 5 presents a discussion of results and Section 6 contains conclusions.

2 DSO-TSO Coordination

This section reviews the state of the art research into DSO-TSO coordination, beginning with a focus on the GB electricity system, followed by a review of academic literature and finishing with a summary of the latest work in developing the traffic light concept.

2.1 DSO market development in GB

The motivation behind a DSO market is to provide a lower cost alternative to network reinforcement triggered by the growth in DERs. Under GB price control regulations, known as RIIO (Revenue=Incentives+Innovation+Outputs)[17], DSOs are encouraged to seek alternatives to reinforcement, and their revenues are not only derived from network upgrades, but also from innovation, such as the introduction of flexibility markets.

Within the GB system, flexibility markets are already under trial in most distribution network regions using the Piclo flex platform [18]. These flexibility markets are predominantly for peak shaving by reducing demand or dispatching generation at a small number of peak occurrences, which could otherwise have triggered network reinforcement. In the initial stages of the Western Power Distribution (WPD) Flexible Power trial [8], flexibility is procured for a 1-year contract and prices are fixed, at around £300/MWh depending on the product, in an attempt to assess the available flexibility and market liquidity. The WPD market has no exclusivity clause meaning DERs can offer services to both the DSO and the TSO. In the event that the DER is not available to the DSO when called upon, the operator of DER would lose revenue through an 'underperformance clawback' [8].

2.2 Academic literature

Much work has been done on modelling DSO markets [7, 19] and proposing system architectures, including the role of the future Distribution System Operator (DSO) [5, 14, 20–22]. However, the literature focusing on models and demonstration on real electricity networks to achieve TSO-DSO coordination, as carried out in this paper, is sparse. In [15] different models are proposed with varying levels of involvement of the future DSO in managing the distribution networks. In the market DSO approach in [15], the DSO can either aggregate DERs in response to TSO signals, or carry out all coordination and aggregation within each local distribution area, providing the TSO with a single aggregated resource at each T&D interface. In the SmartNet project [13, 14], several DSO-TSO coordination schemes are considered including the following:

- Centralised market: the TSO operates the market, the DSO can be involved in a prequalification stage to ensure the TSO's actions do not result in constraints at distribution level.
- Local market: the DSO operates a distribution level market, aggregates cleared services and transfers them to the TSO operated market.
- Shared balancing responsibility: the DSO has balancing responsibility for the distribution grid.
- Common DSO-TSO market: DSO constraints are included in market clearing. Either in a single optimisation process for entire T&D system (TSO and DSO jointly operate) or with separate DSO markets run first.
- Integrated flexibility: TSO, DSO and third parties all bid for flexibility in a common market.

The various models have a range of strengths and weaknesses including complexity, compatibility with existing systems and choice for the DERs as to which market to participate in. The common DSO-TSO market model has been applied in this work, with the DSO market run separately. This offers advantages over prequalification in the centralised market and aggregation of resources in the local market model. Prequalification would mean having to rule some DERs out of the TSO market in the event of constraints, however with a DSO market they can be dynamically compensated when this occurs. Aggregation of resources by a local market operator is not straightforward and requires an aggregated supply curve to be calculated by the DSO for multiple DERs, this was investigated and found to be computationally expensive. Shared balancing responsibility requires the DSO to balance supply and demand at the T&D interface which may reduce the TSOs access to DERs. The focus of the DSO should be on congestion management and the flow over the T&D interface should be left for the TSO to optimise. Integrated flexibility applies a level playing field for access to DERs, however does not account sufficiently for distribution constraint management which will become increasingly important with the growth of DERs.

In [14] the co-ordination schemes are described for the provision of ancillary services, however they can be applied to system balancing, as demonstrated in [20]. The common DSO-TSO model in [20] is decentralised, with the DSO market cleared first. A 'residual supply' function is calculated based on the change in cost with a change in power flow between T&D. This allows the TSO to optimise and pass instructions back to the DSO. In [22], distribution is first optimised then the communication between T&D is carried out using a 'generalised bid' function, a similar concept to the residual supply function, which represents the marginal cost of power generation from distribution. The method used in this work offers an alternative to the DSO aggregating DERs and calculating supply or bid functions, which can be computationally expensive to implement. The method of this paper allows DERs to participate directly in the TSO market with the DSO adjusting the bounds of DERs to prevent constraints.

A distribution market model is presented in [7] along with a literature review of some of the other works into DSO markets. In [7] the dispatch is calculated centrally which does not represent GB market operations. In a comprehensive study of the co-optimisation of T&D markets [19], locational marginal prices are calculated, both at T&D, using a mixture of centralised and decentralised optimisation.

In the work described in this paper, dispatch positions are assumed to be set ahead of the DSO balancing market (e.g. as a result of forward, day-ahead and intraday markets). In the authors' implementation of the 'traffic light' concept, the DSO clears a local balancing market first, activating flexibility to remove any distribution network congestion (in the 'amber' state). With the congestion removed (the 'green' state), any remaining flexibility is available for participation in the TSO market. DERs are not aggregated into the TSO market by the DSO and can participate directly in the TSO market after the DSO market has cleared. The bidding behaviour of the DERs, network congestion and resulting DSO-TSO market prices will dictate which market they are activated in.

2.3 Traffic light concept

The 'traffic light' concept has been discussed in several other works including: [5] where DSO-TSO cooperation in each system state (green/amber/red) is considered but not demonstrated; [23] and [24] where implementations are outlined without any test case demonstrations; [25] and [26] where implementations are demonstrated at LV but with limited consideration of DSO-TSO interaction.

The work presented in this paper aligns most closely with [27], where a local flexibility market model (described in more detail in [28]) is designed, and uses the traffic light concept. A Balancing Responsible Party (BRP) is modelled, with a balancing position in the TSO market, which competes with the DSO for DER flexibility (provided via an aggregator). In [27] distribution network constraints are not modelled, thereby simplifying DER participation outcomes in the TSO markets. The work presented in this paper extends this to explicitly account for distribution constraints and a balancing market representation is provided to relieve these constraints.

This paper will focus on markets for active power balancing services, however, it is acknowledged that DSO markets for ancillary services such as reactive power, as trialled in the Power Potential project [11], as well as markets for inertia and black-start (amongst others) could become important in the future.

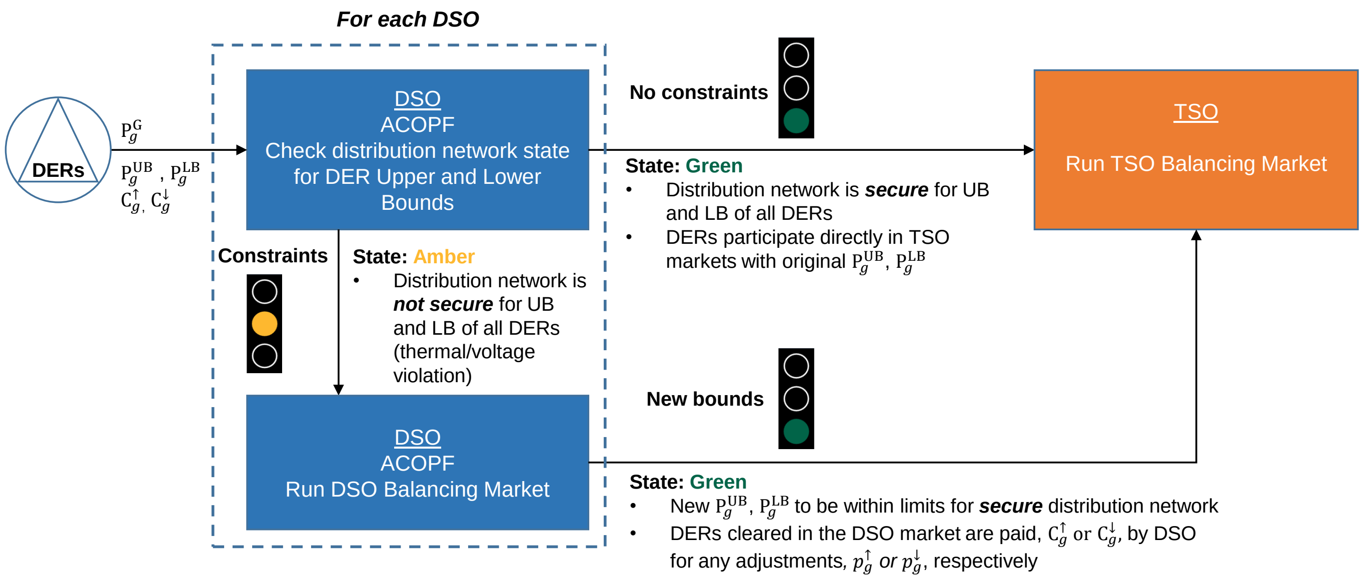

Fig. 3: Illustration of the traffic light style DSO-TSO coordination framework.

3 DSO-TSO balancing coordination model

In this section, a mathematical formulation is presented for the DSO-TSO balancing market coordination model. By presenting scenarios on a distribution network, this work aims to demonstrate occurrences of the DSO and TSO objectives competing for the flexibility offered by DERs, and show how the model prioritises the DSO and TSO objectives. The model formulation is presented along with a case study on a distribution network in the south west of England.

3.1 Problem Formulation

Let us consider a distribution network consisting of a set of demands, $\mathcal{D}$, and a set of DERs, $\mathcal{G}$, connected to this distribution network. DERs can be generation, batteries or demand side response (DSR). In this work, upward DSR means turning down demand, which has the same effect as turning up generation. The real power demand at bus d is denoted by $\mathrm{P}_d^{\mathrm{D}}$ and the set-point of a DER connected at bus g is denoted by $\mathrm{P}_g^{\mathrm{G}}$. Let $p_g^{\downarrow}$ and $p_g^{\uparrow}$ denote the downward and upward re-dispatch variables from the given DER set-point, respectively. The re-dispatch variables are bounded by the DER lower bound, $\mathrm{P}_g^{\mathrm{LB}}$, and upper bound, $\mathrm{P}_g^{\mathrm{UB}}$, parameters. The DER upper and lower bounds are key decision variables for the DSO in the proposed framework, the DSO can adjust these limits to prevent actions by the TSO causing constraints at distribution. This is illustrated in Figure 4 and described in more detail in Section 3.2. Note: the bounds can either be the physical capacity of the DER, or what a DER offers to the market at any given point in time.

The overall objective function of the DSO balancing optimisation is given as follows:

$$\min \sum_{g\in\mathcal{G}} \underbrace{\left(\mathrm{C}_g^{\downarrow} p_g^{\downarrow} + \mathrm{C}_g^{\uparrow} p_g^{\uparrow}\right)}_{\text{Cost of balancing}} + \sum_{d\in\mathcal{D}} \underbrace{\mathrm{V}_d^{\mathrm{D}} \left(\mathrm{P}_d^{\mathrm{D}} - p_d^{\mathrm{D}}\right)}_{\text{Cost of load shedding}} \tag{1}$$

where $\mathrm{C}_g^{\downarrow}$ and $\mathrm{C}_g^{\uparrow}$ are bids and offers from the g-th DER, respectively. The parameter $\mathrm{V}_d^{\mathrm{D}}$ denotes the value of lost load at demand d, and the variable p_d^{D} denotes the demand delivered at demand bus d. The re-dispatch variables are decision variables along with the delivered demand.

The DER constraints are modelled as follows:

$$\mathrm{p}_g^{\mathrm{G}} = \mathrm{P}_g^{\mathrm{G}} + \left(p_g^{\uparrow} - p_g^{\downarrow}\right), \tag{2a}$$

$$\mathrm{p}_g^{\uparrow} \geq 0,\ \mathrm{p}_g^{\downarrow} \geq 0 \tag{2b}$$

The RHS of (2a) models the re-dispatch of DERs and $\mathrm{p}_g^{\mathrm{G}}$ represents the adjusted set point. In addition to the constraints in (2a) to (2c), the following constraints are implemented, reproduced from [29]:

$$\sum_{g\in\mathcal{G}_b} p_g^{\mathrm{G}} = \sum_{d\in\mathcal{D}_b} P_d^{\mathrm{D}} + \sum_{b'\in\mathcal{B}_b} p_{bb'}^{\mathrm{L}} + G_b^{\mathrm{B}} v_b^2, \tag{3a}$$

$$\sum_{g\in\mathcal{G}_b} q_g^{\mathrm{G}} = \sum_{d\in\mathcal{D}_b} Q_d^{\mathrm{D}} + \sum_{b'\in\mathcal{B}_b} q_{bb'}^{\mathrm{L}} - B_b^{\mathrm{B}} v_b^2, \tag{3b}$$

$$p_{bb'}^{\mathrm{L}} = v_b^2 G_{bb} + v_b v_{b'}(G_{bb'}\cos(\theta_b - \theta_{b'}) + B_{bb'}\sin(\theta_b - \theta_{b'})), \tag{3c}$$

$$q_{bb'}^{\mathrm{L}} = -v_b^2 B_{bb} + v_b v_{b'}(G_{bb'}\sin(\theta_b - \theta_{b'}) - B_{bb'}\cos(\theta_b - \theta_{b'})), \tag{3d}$$

$$\theta_{b_0} = 0, \tag{3e}$$

$$v_b^{\mathrm{LB}} \leq v_b \leq v_b^{\mathrm{UB}}, \tag{3f}$$

$$P_g^{\mathrm{LB}} \leq p_g \leq P_g^{\mathrm{UB}}, \tag{3g}$$

$$Q_g^{\mathrm{LB}} \leq q_g \leq Q_g^{\mathrm{UB}}, \tag{3h}$$

$${p_{bb'}^{\mathrm{L}}}^2 + {q_{bb'}^{\mathrm{L}}}^2 \leq (S_{bb'}^{\max})^2, \tag{3i}$$

where $G_{bb'}$ and $B_{bb'}$ are the line conductance and susceptance respectively. Equations (3a)–(3b) are Kirchhoff's Current Law governing real and reactive power balance, (3c)–(3d) are Kirchhoff's Voltage Law, (3e) fixes the phase angle to zero at the arbitrary reference bus, (3f)–(3h) are constraints on voltage, real and reactive power generation respectively, and (3i) is the line flow constraint.

The above formulation is implemented using an open-source power systems simulation tool (OATS) [30] and the resulting nonlinear optimisation problems are solved using an open-source solver (ipopt) [31].

3.2 Framework

In Figure 3, a framework is presented that makes use of the problem formulation in a traffic light style DSO-TSO coordination scheme.

The distribution system is balanced based on the market positions of all DERs along with the anticipated demand for a settlement period (which in this work is 30 minutes). The DSO market runs before the TSO balancing market, to integrate with current operating practise. In the GB system for example, this is currently more than 1-hour ahead of delivery. On this basis, there will be uncertainty over output from DERs, which has not been fully captured in the model formulation at this stage.

The first stage is for the DSO to check the feasibility of possible market outcomes, by taking the positions of all DERs and demands, along with the upper and lower bounds of the flexible DERs. The DSO also takes bids and offers from flexible DERs to move down or up from their respective positions within the limits of the bounds provided. In this work the bid and offer prices, $\mathrm{C}_g^{\downarrow}$ and $\mathrm{C}_g^{\uparrow}$, for the DERs are the same in both the DSO and TSO markets for ease of comparison, however they could be priced differently for each market. The DSO must keep sufficient headroom for DERs with ancillary service contracts (such as frequency response) during their tendered availability windows.

The DSO market then clears using ACOPF (AC Optimal Power Flow) driven by OATS [30] to determine any network constraints for all DERs at their upper bounds and at their lower bounds. The objective function of the optimisation (1) is to minimise the costs of adjustments required to remove any network constraints.

3.2.1 Green state: If there are no constraints for the submitted upper and lower bounds of DERs, there will be no need for adjustments and the cost will be zero. There is no cost for import/export to the transmission system, which will make up any shortfall or take any excess generation from the distribution system, within network limits.

The DERs can then participate directly in the TSO market, offering any flexibility within the bounds as cleared by the DSO. This is considered the 'green' state where any actions by the TSO will not cause constraints within distribution.

3.2.2 Amber state: If the DSO requires adjustments to be made to $\mathrm{P}_g^{\mathrm{LB}}$, $\mathrm{P}_g^{\mathrm{UB}}$ or $\mathrm{P}_g^{\mathrm{G}}$ for any of the DERs due to network constraints, this is considered the 'amber' state. The DSO market is initiated to resolve these network constraints, by making adjustments to the bounds based on the minimisation of (1). In the timeline for the DSO market clearing in the amber state (Figure 4), the DSO receives physical notifications (including $\mathrm{P}_g^{\mathrm{LB}}$, $\mathrm{P}_g^{\mathrm{UB}}$ and $\mathrm{P}_g^{\mathrm{G}}$) from the DERs, 2 hours ahead of delivery. The DSO has an hour to manage network constraints and provide any modified positions and bounds to the TSO at gate closure, 1 hour ahead of delivery. The DSO can concurrently check both the upper and lower bounds, UB and LB respectively, by setting $\mathrm{P}_g^{\mathrm{G}}$ to $\mathrm{P}_g^{\mathrm{UB}}$ and $\mathrm{P}_g^{\mathrm{LB}}$ respectively for all DERs, as shown in Figure 4. If any adjustments are required to maintain the network within thermal and voltage constraints (outlined in (3a) - (3i)), for all DERs either at their upper or lower bounds, the DSO then tightens the original bounds for DERs participating in the TSO market. This returns the network to the 'green' state and the DERs now participate directly in the TSO market, within the new limits set by the DSO, without causing constraints at distribution level.

3.2.3 TSO balancing market modelling: In this work the transmission system is not modelled in any detail due to the complexity of modelling balancing actions for the GB transmission network. The transmission system, or wider grid, is represented by a single bus with a generator representing import or export to the grid, as shown in Figure 5. After DSO market clearing, the distribution system demand, $\sum_{d\in\mathcal{D}} p_d^{\mathrm{D}}$, is aggregated to the transmission bus and DERs are added to the transmission bus as individual units with values of $\mathrm{P}_g^{\mathrm{LB}}$, $\mathrm{P}_g^{\mathrm{UB}}$ cleared by the DSO.

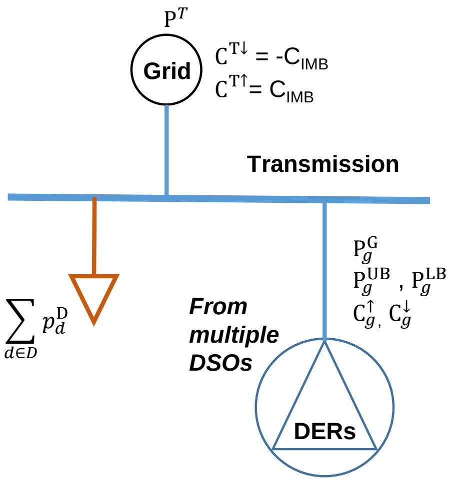

Fig. 5: Transmission bus with aggregated distribution demand and DERs.

The transmission import/export flow, P^T, makes up the difference between total DER positions ($\sum_{g\in\mathcal{G}} p_g^{\mathrm{G}}$) and total demand ($\sum_{d\in\mathcal{D}} p_d^{\mathrm{D}}$) at distribution after DSO market clearing, including losses, thus;

$$\mathrm{P}^T = \sum_{g\in\mathcal{G}} p_g^{\mathrm{G}} - \sum_{d\in\mathcal{D}} p_d^{\mathrm{D}} + \mathrm{Losses} \tag{4}$$

where P^T is bounded by the secure (N-1) transmission transformer capacity.

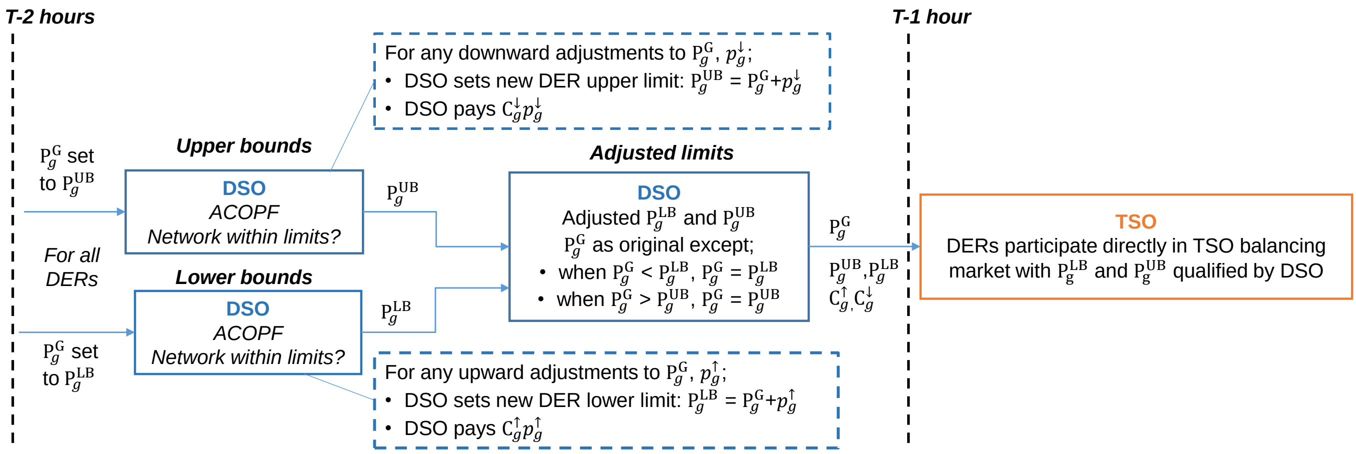

Fig. 4: DSO amber state timeline: upper and lower bounds adjustments. T is delivery, i.e. T-2 is 2 hours ahead of delivery.

The TSO market operates with the same objective function as the DSO market (see (1)). A DCOPF balancing model could be sufficient for the TSO, due to lower losses and voltage variation. DSO market participants are not expected to cover line losses which are included in P^T. The DSO balancing market is primarily for congestion management, line losses would be part of use of system charges and not paid by DSO balancing market participants.

There is no cost to the adjustment of P^T to balance generation and demand in the DSO market, however, in the TSO market, any change to P^T comes at the upward, $C^{T\uparrow}$, or downward, $C^{T\downarrow}$, cost for increased or decreased grid import respectively.

In this model, any actions by the TSO market will be purely for arbitraging the cost of adjusting grid import/export, $C^{T\uparrow}$/$C^{T\downarrow}$, against the cost of adjusting DERs, $C_g^{\uparrow}$/$C_g^{\downarrow}$. Negative costs represent payments to the TSO, therefore if $C^{T\uparrow}$ or $C^{T\downarrow}$ are negative, the TSO could profit by increasing or reducing P^T. However, to maintain balance of supply and demand, any adjustment to P^T must be balanced by a change in DER output P_g^G with corresponding cost, $C_g^{\uparrow}$ or $C_g^{\downarrow}$. For the TSO to carry out arbitrage, any income for the TSO from the adjustments to P^T must be greater than the cost of re-balancing by adjusting DER output. It is not suggested that the primary objective of the TSO in a balancing market is for arbitrage, in this work arbitrage represents occasions when the TSO would have a demand for DERs in system balancing. The transmission network could be modelled in more detail to include balancing actions by the TSO, however this is outside of the scope of this work.

The grid import/export cost is represented by the 2018 GB imbalance price (C^{IMB}) from [3]. The imbalance price is the cost to the TSO of correcting system imbalance between supply and demand and does not include balancing actions due to network constraints. The system imbalance price is used in this work to show the value of DER flexibility for a range of balancing prices, although in reality, accepted DER actions could be part of the imbalance price calculation. Some expected market outcomes are outlined below;

- *At times of high imbalance price, DERs will be turned up.* The transmission bid price, $C^{T\downarrow}$, equals $-C^{IMB}$, therefore, at times of high positive C^{IMB}, when DERs have offer prices ($C_g^{\uparrow}$) lower than the C^{IMB}, the DERs will be turned up and TSO import P^T can be turned down. The TSO will profit by the difference between C^{IMB} and $C_g^{\uparrow}$. Therefore upward availability will be rewarded at times of high imbalance price. Highly positive prices represent periods when the market is short and the TSO pays a premium to reduce power flow to distribution.
- *At times of highly negative imbalance price, DERs will be turned down.* The transmission offer price, $C^{T\uparrow}$, equals C^{IMB}, therefore, when DERs have bid prices ($C_g^{\downarrow}$) lower than $-C^{IMB}$ (in the case of a negative imbalance price), the DERs will be turned down and TSO import (P^T), will be turned up. The TSO will profit by the difference between $-C^{IMB}$ and $C_g^{\downarrow}$. However this is only in the case of negative C^{IMB} which will result in a negative $C^{T\uparrow}$, or in the case of negative $C_g^{\downarrow}$ from the DERs, either of which can result in income for the TSO for arbitrage. Highly negative prices represent periods when the market is long and the TSO will pay to increase power flow to distribution.

In the following sections, the DSO-TSO balancing market coordination model developed in this section, is demonstrated on a GB distribution network.

4 Case Study: South-West of Cornwall

Part of the distribution network in Cornwall in the south west of England, is used to demonstrate the application of a traffic light style system to coordinate separate DSO and TSO balancing markets. The modelled network is illustrated in Figure 6.

Network data is taken from the long term development statement of the DSO [32]. The network model contains a single 400 kV transmission bus, connected to a ring of 132 kV distribution network.

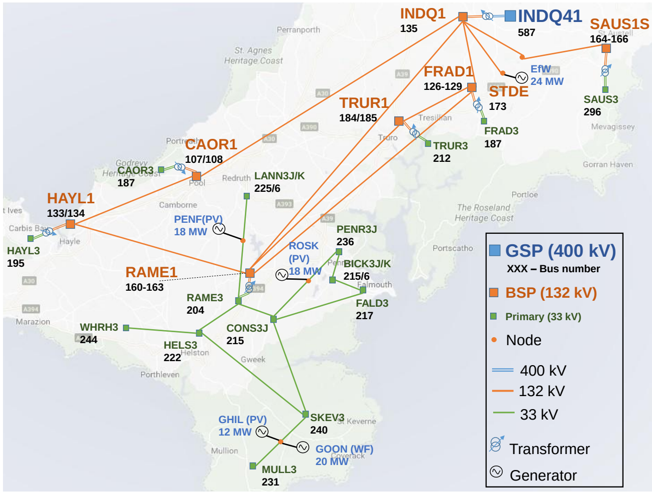

Fig. 6: Schematic of Cornwall network used for DSO balancing study, EfW - Energy From Waste Plant, WF - Wind Farm

Six bulk supply points (BSPs: substations with transformers which step voltage down from 132 kV to 33 kV) within Cornwall are modelled: Rame, Hayle, Camborne, Truro, Fraddon and St Austell. For all BSPs except Rame, demand and generation are aggregated to the bus on the 33 kV side of the BSP transformers. BSP transformer constraints are therefore included in the model, and are used to calculate the firm and reverse capacities in Tables 1 and 2. At Rame, the 33 kV network is modelled (see Figure 6), and demand and generation are lumped to the 33 kV side of the eleven primary (33 kV / 11 kV) substations.

The Cornwall network allows the traffic-light style coordination system of this paper to be demonstrated. Distribution constraints are resolved by a DSO, and DER bounds, for participation in a TSO market, are qualified. The competition for procuring flexibility, between the DSO and TSO, is explored in a highly constrained region. Tables 1 and 2 describe existing peak demand and embedded generation characteristics of the network, as well as how these characteristics may change under a modelled 2030 scenario prescribed in the National Grid Future Energy Scenarios (FES) [1]. The particular FES scenario that was modelled, known as Community Renewables (CR), has a large uptake of renewables (wind and PV) at distribution level along with high levels of EV and heat pump integration. The CR scenario was chosen to assess the need for a DSO market with the highest anticipated levels of DER.

Table 1 Cornwall bulk supply point demand headroom current and 2030 Community Renewables scenario, MVA; data: [1, 32].

BSP	Firm Capacity[1]	Peak Demand	Demand Headroom[2]	2030 Peak Demand[3]	2030 Demand Headroom
Rame	105	72.3	32.7	94.8	10.2
Hayle	60	61.2	-1.2	73.5	-13.5
Camborne	180	43.5	136.5	52.3	127.7
Truro	60	60.4	-0.4	79.2	-19.2
Fraddon	120	74.1	45.9	97.1	22.9
St Austell	90	61.6	28.4	74	16

[1] Firm capacity is based on (N-1) secure transformer capacity for grouped demands greater than 60 MW. For example, the firm capacity for Truro is from one of the two Truro BSP transformers, due to grouped demand being above 60 MW. This is a simplified approximation of the P2/6 security of supply recommendation [33] which is the distribution security standard in GB.

[2] Headroom is calculated from Firm Capacity - Peak Demand (as in [34]). This does not include minimum embedded generation which would increase demand headroom.

[3] 2030 Demand Estimate for Community Renewables scenario [1].

Table 2 Cornwall bulk supply point generation headroom, current and 2030 Community Renewables scenario, MVA; data: [1, 34].

BSP	Reverse Capacity[1]	Gen Capacity	Gen Headroom[2]	2030 Gen Capacity[2]	2030 Gen Headroom
Rame	73	59.1	13.9	271.7	-198.7
Hayle	60	51.3	8.7	106.6	-46.6
Camborne	67.7	23.5	44.2	98.8	-31.1
Truro	60	82.9	-22.9	278.1	-218.1
Fraddon	120	162.5	-42.5	280.5	-160.5
St Austell	68.6	47.3	21.3	170.7	-102.1

[1] Reverse capacity is based on (N-1) secure transformer reverse capacity for grouped demands greater than 60 MW. For example, the reverse capacity for Rame is from two of the three Rame BSP transformers, due to grouped demand being above 60 MW.
[2] Headroom is calculated from Reverse Capacity - Gen Capacity (as in [34]). This does not include minimum demand which would increase headroom; thermal and voltage constraints are modelled in the ACOPF within the Rame 33 kV network, but ignored in the other BSPs.
[3] 2030 Generation Estimate for Community Renewables scenario [1].

The capacity of each generation and flexible demand technology included in the 2030 model is shown in Table 3. Demand profiles are based on measured BSP flows from [3] for the year 2017 for an area with minimal embedded generation. Projected deployment of EVs and heat pumps, under the 2030 CR scenario, were then added to the baseline BSP demand profile, to create the 2030 demand profiles. Generation profiles for PV and Wind are from the Renewables Ninja [35] resource using 2016 data.

Table 3 Cornwall generation and flexible demand by technology[1], 2030 Community Renewables scenario MW; data: [1], [32].

BSP	PV	Wind	Firm[2]	Battery	DSR[3]
Rame	195.8	59.0	16.9	2	19.5
Hayle	47.2	22.2	37.2	0	4.4
Camborne	74.2	22.6	2	0	8.8
Truro	183.7	86	4.4	4	18.8
Fraddon	181.4	80.2	14.9	4	22.7
St Austell	115.2	30.1	21.4	4	12.4

[1] 2030 Community Renewables gives estimate for total PV, wind, firm and battery within the Indian Queens grid supply point (GSP). New generation is assigned to BSPs within the GSP region based on existing distribution of technologies.
[2] Firm generation is modelled as always available and includes biomass, energy from waste and diesel.
[3] DSR (Demand Side Response): All new EV and heat pump demand under the 2030 CR scenario is modelled as available for DSR with downward flexibility. These values are the peak values but will vary with instantaneous demand.

4.1 The cost of flexibility

A key component of modelling the DSO and TSO balancing markets is the assumed bid and offer prices of the DERs to provide flexibility. There is a high uncertainty around predicting prices of electricity and flexibility in 2030. Within this case study, 2018 price data for both ancillary services and the National Grid Balancing Market, described in Tables 4 and 5 respectively, were used as a guide to represent two price cases. The two developed price cases are:

1. *Cheap demand side response (DSR)*: where demand side flexibility is cheaper than curtailment of renewables and
2. *Cheap Curtailment*: where it is cheaper to curtail renewables than to flex demand.

Specific price data for each of these cases is outlined in Table 6. The positive prices in Table 6 ensure that the DSO (whose objective function is represented by (1) will not carry out balancing actions for any other reason than network constraints. There is no cost to the DSO on import/export to transmission which introduces a potential problem of the DSO using DERs for arbitrage. The DSO would profit from turning down any DERs with negative bids (negative bids represent payment to the DSO), with no cost for increased import from transmission. This could be particularly problematic if the TSO had a shortage, which the DSO could exacerbate by turning down all DERs with negative bids, to profit from arbitrage. If all bids and offers are positive, the DSO will pay for any adjustments to DER positions, therefore preventing arbitrage.

The 'Cheap DSR' case is more desirable in terms of minimising curtailment (and utilising low carbon generation), however, it could be cheaper to curtail generation at times of maximum output than to flex demand. Hence, the 'Cheap Curtailment' case is modelled for comparison.

Table 4 GB Average cost of ancillary services; data: [2].

Service	Average Utilisation Price (£/MWh)	Year
Demand Turn-Up	65	2018
Short Term Operating Reserve (STOR)	142	2016

Table 5 GB volume weighted average cost of 2018 National Grid BM actions by technology; data: [3].

Technology	Bid[1](£/MWh)	Offer[2](£/MWh)
Demand Side[3]	-58[4]	28
Gas	-42	85
Coal	-47	83
Hydro	-14	104
Pump Storage	1	114
Biomass	8	73
Wind	73	-

[1] Bid to Turn-down Generation/Turn-up demand. In the GB balancing mechanism, negative bids are payments by the TSO whereas in this study negative bids are payments to the TSO for consistency with the model.
[2] Offer to Turn-up Generation/Turn-down demand.
[3] Data for Aug 18 - Jan 19 for aggregator volumes shown in Figure 1. It is assumed that aggregators represent demand side (they are registered as supplier type BM units), however they may include embedded generation.
[4] A negative bid means on average the aggregated BM units are paying to turn down generation/turn-up demand, this indicates embedded generation (e.g. diesel generator) with a fuel cost saving.

Table 6 DER pricing: Cheap curtailment and Cheap DSR cases [1]

	Cheap Curtailment		Cheap DSR	
Technology	**Bid**	**Offer**	**Bid**	**Offer**
Wind	10	20	60	20
PV	10	20	60	20
Firm[2]	2	20	20	20
Battery	70	70	70	70
Mixed[3]	5	20	40	20
DSR[4]	60	70	10	30

[1] The prices in Table 4 and 5 are used as a guide for setting the DER price cases.
[2] Firm generation includes biomass, energy from waste and diesel. They may be willing to turn down at low cost due to fuel savings.
[3] Aggregated mixed technology balancing units from lower voltages.
[4] Demand Side Response (DSR): flexibility from heat pumps and EVs.

5 Results and Discussion

The following scenarios are analysed on the Cornwall network (Section 4), using the DSO-TSO balancing market coordination model for a 24 hour period (with 48 half hour periods);

1. Maximum import to distribution: Maximum demand and minimum output from intermittent generation (winter day).
2. Maximum export from distribution: Minimum demand and maximum output from intermittent generation (summer day).

3. Negative transmission Imbalance Price.

Each scenario is executed using 2030 Community Renewables demand and generation profiles for the ‘Cheap Curtailment’ and ‘Cheap DSR’ DER price cases as outlined in Table 6.

5.1 *Cheap Curtailment*

In the ‘Cheap Curtailment’ case, wind, PV and firm generators are curtailed at lower cost than activating DSR or batteries. The most interesting results, in terms of both the DSO and TSO accessing DER flexibility, were observed for maximum import and negative imbalance price.

5.1.1 Maximum Import: Under the DSO-TSO balancing coordination methodology developed in this work, demand must be met with all DERs set to their lower bounds, to achieve the ‘green’ state. If the DSO load flow predicts constraints in the distribution network, the DSO market is run (‘amber’ state). To return to the ‘green’ state, the DSO may increase the lower bounds on generation to guarantee peak demand is met, or use DSR and batteries to reduce the peak demand.

The maximum import case (see Figure 7), which occurred on a day of high demand and low DG output, has a peak demand of approx. 420 MW at 17:30, at a time when solar and wind output are minimal.

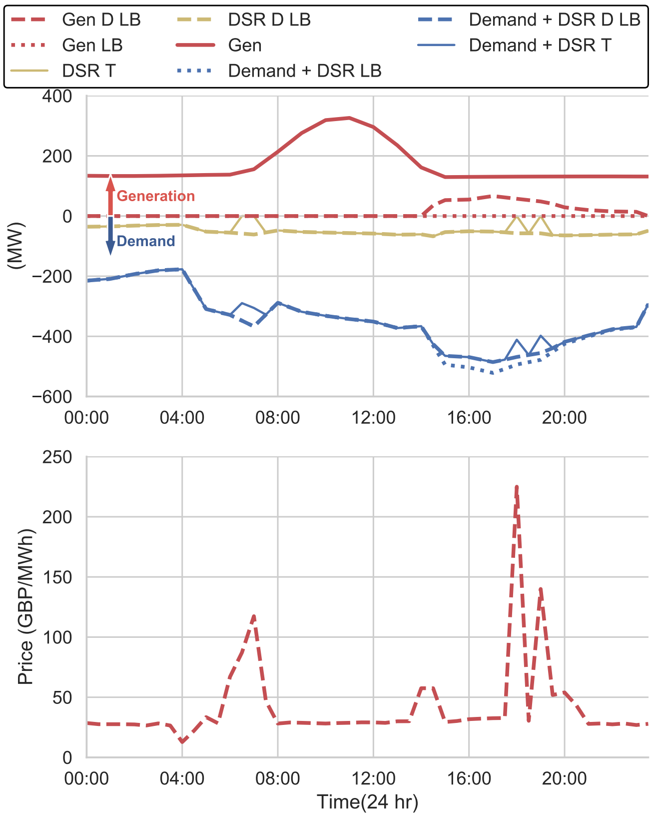

Fig. 7: **Top Plot:** Dispatch by DSO and TSO for ‘Cheap Curtailment’ for 24 hour period of Maximum Import (in January). D and T are used to indicate results of the DSO and TSO markets respectively. Dotted lines are unmodified positions. UB - Upper Bound, LB - Lower Bound. **Bottom Plot:** Transmission Imbalance Price.

At 14:30, the ‘amber’ state (DSO market) is triggered, due to insufficient import capacity to meet demand with DERs at their lower bounds. To ensure there is sufficient generation to meet the peak demand, from 14:30 till 23:00, the DSO pays generators their offer price to increase their lower bounds (see increase in ‘Gen D LB’ in Figure 7). Once these lower bounds have been fixed by the DSO, the TSO cannot reduce generation below these lower bounds during this period.

Upward DSR (i.e. reducing demand) is used by the DSO between 14:30 and 20:00, as there is insufficient import capacity to meet peak demand in constrained network areas (Rame, Truro and Fraddon) during this peak time. The amount of upward DSR available to the TSO for the two price spikes (£220/MWh and £140/MWh), at around 18:30 and 19:30, was subsequently reduced due to DSR being committed by the DSO. The DSO and TSO both wanted upward DSR during those price spikes, this is an example when the DSO dispatch aligns with the TSO’s objective.

Truro is the most demand constrained region in Cornwall (see Table 1) for the 2030 CR scenario. In Truro, during the 5 peak demand hours of the maximum import scenario (see Figure 8), DSR was used to its upper limits and generation lower bounds were raised as far as possible, however up to 2.7 MW of load shedding was still necessary. The DSO market would quickly highlight the need for flexibility in this region as a high price would be paid to prevent load shedding.

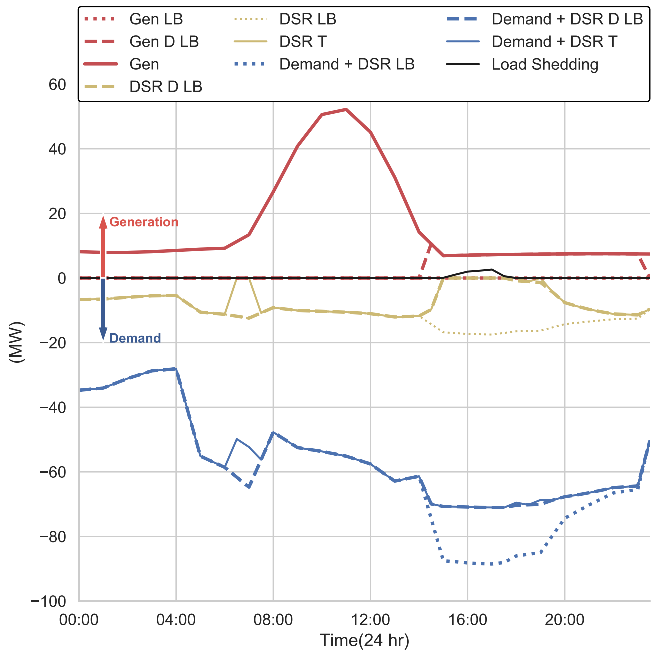

Fig. 8: Dispatch by DSO and TSO for ‘Cheap Curtailment’ in Truro BSP for 24 hour period of Maximum Import. D and T are used to indicate results of the DSO and TSO markets respectively. Dotted lines are unmodified positions. UB - Upper Bound, LB - Lower Bound.

5.1.2 Negative Imbalance Price: Negative imbalance prices are rare in GB, however they are increasing in frequency due to low demand and high output from intermittent generation. A 6 hour consecutive period of negative imbalance price occurred on the 24th March 2019 and a 9 hour period occurred on the 26th May 2019 [3]. Negative prices are included in this work to represent cases where the TSO has a requirement to curtail intermittent generation, which is a common occurrence in GB due to transmission network constraints [36]. The March negative imbalance price has been modelled with the dispatch from the maximum export scenario where high renewable output results in a requirement for curtailment (see Figure 9).

At around 06:00 the DSO enters the ‘amber’ state due to the upper bounds of generators exceeding distribution network limits. Generation is curtailed in the DSO market from 06:00 until 16:00, during this period the upper bounds and set points of the generators are reduced by the DSO. In the ‘Cheap Curtailment’ case generators provide the lowest cost reduction in export to return the network to the ‘green’ state.

The curtailment by the DSO coincides with a period of curtailment by the TSO (due to a highly negative imbalance price), between 10:00 and 16:00. The remaining downward headroom from

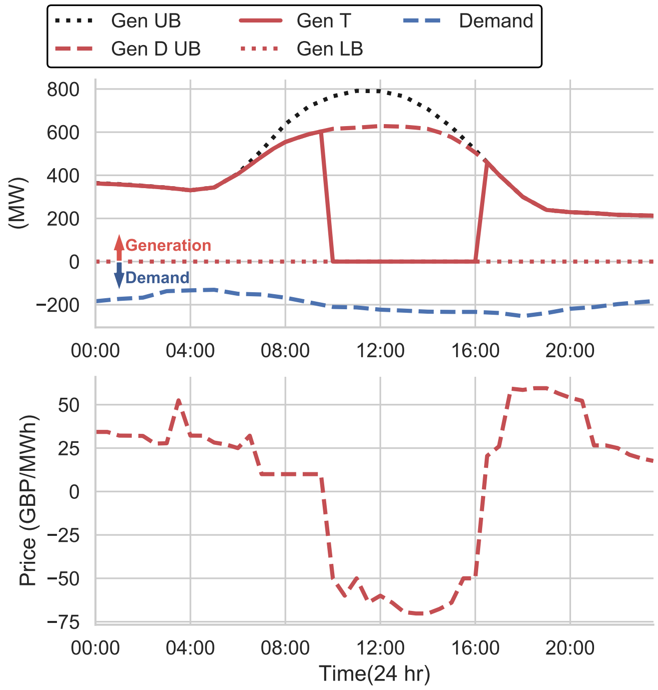

Fig. 9: **Top Plot:** Dispatch by DSO and TSO for 'Cheap Curtailment' for 24 hour period of negative imbalance price. D and T are used to indicate results of the DSO and TSO markets respectively. Dotted lines are unmodified positions. UB - Upper Bound, LB - Lower Bound. **Bottom Plot:** Transmission Imbalance Price.

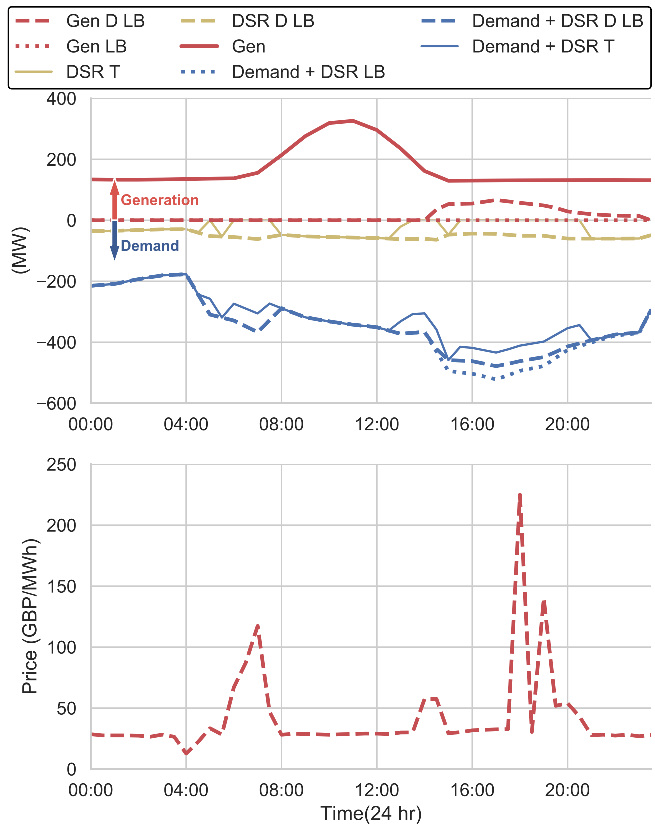

Fig. 10: **Top Plot:** Dispatch by DSO and TSO for 'Cheap DSR' for 24 hour period of Maximum Import (January). D and T are used to indicate results of the DSO and TSO markets respectively. Dotted lines are unmodified positions. UB - Upper Bound, LB - Lower Bound. **Bottom Plot:** Transmission Imbalance Price.

the DERs (after DSO market clearing), is used by the TSO for arbitrage. This is another case where DSO and TSO objectives align; during times of high renewables output it is foreseeable that both the TSO and DSO will have a requirement to reduce output.

In terms of costs, the DSO paid generators to reduce output whereas the TSO profited from reducing the remaining output using arbitrage. The former could be seen as increasing balancing costs and the latter reducing.

5.2 *Cheap DSR*

In the 'Cheap DSR' case the cost of utilising DSR in the DSO balancing market is lower than that of generation or batteries. In the maximum import scenario the DSO uses DSR to meet peak demand, whereas for maximum export, DSR is used to reduce curtailment. In both cases the TSO uses the remaining DER flexibility for arbitrage.

5.2.1 Maximum Import: The results of the maximum import scenario (see Figure 10) are very similar for the 'Cheap DSR' and 'Cheap Curtailment' cases. The only difference is the volume of DSR used for arbitrage by the TSO, due to the offer price being £30/MWh in 'Cheap DSR' and £70/MWh for 'Cheap Curtailment'.

The DSO market increased the lower bound of generation during peak demand (between 14:30 and 24:00), the same as in the maximum import scenario for the 'Cheap Curtailment' case. The generators are operating at their upper bounds, therefore increasing the lower bounds does not require set point adjustment in either cases. The offer price of generation reflects this, at £20/MWh in both cases. The DSR is operating at its lower bounds (representing maximum demand), therefore increasing DSR lower bounds involves increasing the set points which comes at a higher offer cost of £30/MWh even in the 'Cheap DSR' case.

5.2.2 Maximum Export: In the maximum export scenario (see Figure 11), at 06:00 the DSO enters the 'amber' state, i.e. the DSO market is activated, due to the generator upper bounds breaching N-1 secure transformer reverse capacity limits. DSR and generator (generator dispatch not shown in Figure 11 to focus on DSR actions) upper bounds are reduced between 06:00 and 16:00. DSR is used preferentially due to having a lower bid price. The generators' output (and upper bound) is reduced, whereas the DSR is operating below its upper bound, and only has to reduce the upper bound (not its output).

However, the reduced upper bound of DSR by the DSO, comes at an opportunity cost of reduced upward flexibility available to the TSO. The TSO can still access remaining upward DSR during periods of higher imbalance price (i.e. 05:30, 15:00, 16:00, 17:30). This allowed the DSO to use the most economic source of flexibility to manage constraints and the TSO to profit from arbitrage. This is an example of DSO and TSO objectives not aligning, the DSO limiting the provision of DSR to the TSO due to export constraints.

5.3 *Tractability and robustness of proposed method*

The tractability of the TSO-DSO coordination model is assessed for multiple DSOs and larger distribution networks. Different solvers are compared to assess the robustness of the non-linear programming (NLP) solver ipopt in producing accurate results of the objective function (1) compared to other available NLP solvers.

5.3.1 Run-time for Multiple DSOs: The coordination model has been applied to problems containing multiple DSOs to demonstrate the scalability of the method. The same distribution network (Figure 6) was replicated for each DSO, with the total number of DERs participating in the TSO market increasing with additional DSOs. The results of computation time for a single timestep for each DSO and the TSO are shown in Table 7 for between 1 and 4 DSOs. Simulations were run on a 3.4 GHz Intel Core i6-3770 with 16 GB of RAM.

The DSO balancing markets are solved independently and in parallel prior to the TSO's gate closure. The computation time per DSO is therefore equal regardless of the number of DSOs and is based on the 60 node distribution network illustrated in Figure 6. The model

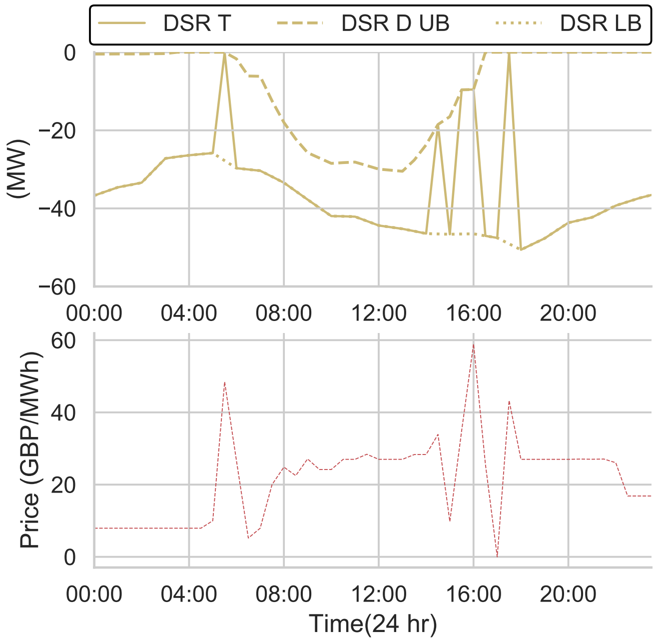

Fig. 11: **Top Plot:** Dispatch by DSO and TSO for 'Cheap DSR' for 24 hour period of Maximum Export (August). D and T are used to indicate results of the DSO and TSO markets respectively. Dotted line is unmodified position. UB - Upper Bound, LB - Lower Bound. **Bottom Plot:** Transmission Imbalance Price.

could be extended to include power flows between DSOs at distribution level, however, this is outwith the scope of this work. The TSO computation time increases with the number of DERs in the TSO balancing optimisation. However, the time taken for the TSO market to clear is significantly less than the DSO market as there is no transmission network modelled. Practically, the transmission network model would result in a significant increase in computational time for the TSO, which would also scale with the number of DERs.

Table 7 Computation time for a single timestep for multiple DSOs

Number of DSOs	**Number of nodes**	**Number of DERs**	**Time per DSO (s)**	**Time for TSO (s)**
1	60	62	7	1.10
2	120	124	7	1.60
3	180	186	7	3.23
4	240	248	7	3.70

5.3.2 Run-time for increasing size distribution network: The distribution model has been extended to illustrate the tractability of the proposed solution for a larger number of nodes. Table 8 provides information on the 60, 256 and 1001 node networks studied and their run times. To produce the 258 node network, a replica section of the Rame 33 kV network is added to all the primary substations shown in Figure 6. The 1001 node network was produced by adding a 11 kV distribution feeder replicated at several secondary substations across the 33 kV network.

Table 8 Computation time for increased distribution network size

Number of nodes	**Number of DERs**	**Time for DSO (s)**	**Time for TSO (s)**
60	62	7	1.10
258	225	28	2.20
1001	790	150	5.30

The 258 node network is representative of the size of the entire 33 kV network in the region, and solves in reasonable time. However, a network which includes 11 kV or below will have tens to hundreds of thousands of nodes. The computational time for the DSO increases significantly for the 1001 node network, therefore a fast optimisation technique, such as dual decomposition [37], would be required for this approach to scale. Increasing the number of DERs entering the TSO balancing market, for example by decreasing the minimum entry capacity, will have implications for the TSOs dispatch optimisation. New tools will be required for both the TSO and DSO to handle the vastly increasing problem size if networks are to be modelled and operated down to lower voltages with more deeply embedded market participants.

5.3.3 Robustness of the solution: The ACOPF problem being solved in the model is non-linear and the NLP technique employed does not guarantee a global optimum solution. To assess the accuracy of the solver employed in this work (ipopt), results of the objective function (1) for a single snapshot, are compared using a range of NLP solvers, for the 60, 258 and 1001 node networks in Table 9. Results for the 60 node network are almost identical for all 5 NLP solvers, the maximum percentage difference in objective function is seen between ipopt and the SNOPT solver of 1.5% for the 258 Node network. Although these errors are small, it would be desirable to explore convex relaxation approaches in future applications of this method to guarantee a global minimum.

Table 9 DSO balancing objective function (1) with selected non-linear programming solvers

	Objective Function (£)		
Solver	60 Node	258 Node	1001 Node
Ipopt	332.6	3575.85	6050.31
Knitro	332.99	3581.87	6066.18
Conopt	332.98	3596.88	6061.52
filterSQP	332.98	3589.79	6064.21
SNOPT	332.98	3628.83	6123.85

6 Conclusion

Effective operational coordination of the DSO-TSO interface remains an area in development for power systems. In this work, the authors' implementation of the traffic light concept, has been demonstrated to provide a simple and effective mechanism to coordinate DSO and TSO balancing markets.

A novel element of the work is that the DSO clears the DERs' upper and lower bounds (of active power output) for participation in the TSO market, to maintain the distribution network in the 'green' state (i.e. within network limits). This DSO market provides a mechanism to compensate DERs for the opportunity cost of adjusting their lower and upper bounds in the TSO market.

The main findings for the 2030 representative scenarios modelled, with high levels of DERs, were as follows;

- The DSO's actions did not severely limit the access of the TSO to DERs.
- When the DSO had to access DER flexibility in the DSO market due to network constraints, there was flexibility remaining for the TSO market.
- In most cases modelled, the DSO and TSO objectives were aligned, however the allocation of costs and benefits of flexibility between them is an area for future work.

This model has been shown to be easily expanded to multiple DSOs feeding into the TSO market or to support competition between independent 'aggregators'; the DERs in each DSO region compete in the TSO market after clearing upper and lower bounds with the respective DSOs. In this work the DSOs are assumed not to be electrically connected, allowing the DSO's problems to be solved in parallel.

The DSO was not allowed to benefit from arbitrage in this model, whereas the TSO market was purely operated for arbitrage. The results of this study are highly dependent on the prices modelled, and resulting merit order. Prices have been chosen to illustrate differing dispatch of DERs depending on price and depending on the DSO's and TSO's objectives.

Coordination schemes are still emerging and with the full definition of terms just beginning to be developed (e.g. [38]), there continues to be barriers for DSO-TSO balancing and congestion management. Uncertainty in renewable generation forecasting will also have an increasing impact on network balancing. It is likely that this will require probabilistic methods to account for forecasting uncertainty. It is acknowledged that constraints may be more likely to occur at LV with the proliferation of EVs and heat pumps connected at this level. Extending the DSO-TSO balancing market coordination to LV will pose significant computational challenges due to the large number of nodes and DERs.

Acknowledgment

This work is supported by the EPSRC Centre for Doctoral Training in Wind and Marine Energy Systems (EP/G037728/1) and the EPSRC AGILE project (EP/S003088/1).

EPSRC Data Statement: All data produced by this research is contained within the paper and supplementary materials. GB balancing mechanism data is available from Elexon Balancing Mechanism Reporting Service at www.bmreports.com.

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