DEPARTMENT OF ELECTRONIC & ELECTRICAL ENGINEERING

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DSO-TSO coordination and distribution network congestion management

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Abstract

Flexibility from distributed energy resources (DERs) such as electric vehicles (EVs), solar photovoltaics, wind generators and battery storage, has the potential to significantly reduce the network reinforcement and operating costs required for the decarbonisation of the electricity system. New tools are required by the transmission system operator (TSO) and distribution system operator (DSO) to coordinate access to DER flexibility while maintaining stable system operation. According to the 2019 TSO-DSO report by the associations representing European distribution and transmission system operators ‘DSOs and TSOs need to co-ordinate closely for the use of flexibility to fulfil their missions as defined in regulation’. New coordination models have been proposed in academia as part the European Union SmartNet project, and a world-first regional reactive power market for DERs has been demonstrated in the South East of England in the ‘Power Potential’ project. With this in mind, this thesis aims to answer the following research questions:

1. How can access to distributed flexibility be coordinated between the DSO and TSO for system balancing and distribution system congestion management?
2. How can distribution system congestion management be scaled and coordinated with the TSO for millions of flexibility providers down to LV level?

To investigate these problems, novel DSO-TSO coordination schemes, under *Local* and *Decentralised market* frameworks, have been developed and demonstrated on a distribution system with high DER penetrations. In the *Local market*, DERs are cleared by the DSO to participate directly in the TSO market, whereas in the *Decentralised market,* the DSO aggregates DER flexibility to the Transmission-Distribution interface for participation in the TSO market. Case studies have been investigated on the performance of the DSO-TSO coordination schemes, and it has been concluded that the *Local market* provides the most promising coordination mechanism in terms of complexity, tractability, and compatibility with the existing TSO balancing market operation of Great Britain. By operating multiple DSO regions in parallel, the *Local market* has been demonstrated to offer a more scalable solution than a single centralised network model. In the cases studied, it was observed that the requirements of the DSO and TSO generally aligned, however, when this was not the case in the *Local market,* the DSO is given priority access to DERs to solve distribution level constraints and any remaining flexibility is made available to the TSO.

The DSO-TSO coordination schemes developed in this thesis solve congestion on balanced medium/high voltage networks using optimal power flow (OPF) techniques in a GB 'balancing' style market operating close to gate closure (1-2 hours ahead of delivery). However, this solution is not considered suitable for application to the millions of domestic customers connected at low voltage (LV). This is because it assumes balanced phases whereas LV networks are often unbalanced and existing three-phase OPF techniques for unbalanced networks may require too much computational overhead (processing power and time). Scalable three-phase LV congestion management solutions are required to minimise the amount of network reinforcement required to facilitate the electrification of heat and transport. In this thesis, a novel and scalable LV congestion management scheme (CMS) has been developed and integrated with the *Local market* DSO-TSO coordination scheme to provide the DSO and TSO access to EV flexibility located at household level while respecting LV network constraints. By applying the CMS to a set of LV networks, it is found that the hosting capacity for EVs can be more than doubled compared to uncoordinated EV charging. The LV CMS represents a key research output from the work of this thesis. It provides a way to access distributed flexibility located at LV in a coordinated way such that the DSO and TSO can achieve system balancing and incorporate distribution system congestion management while addressing the scalability issues.

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Glossary of Terms

ANM – Active Network Management

ASHP – Air Source Heat Pump

BETTA - British Electricity Trading and Transmission Arrangements

BRP – Balancing Responsible Party

BSP – Bulk Supply Point

CMS – Congestion Management Scheme

CMP – Congestion Management Provider

DER – Distributed Energy Resource

DG – Distributed Generator

DLMP – Distribution Locational Marginal Price

DNO – Distribution Network Operator

DSO - Distribution System Operator

DSR – Demand Side Response

DUoS – Distribution Use of System

ETYS - Electricity Ten Year Statement

EHV – Extra High Voltage (275 kV / 400 kV)

EV – Electric Vehicle

GB – Great Britain

GSP – Grid Supply Point

HV – High Voltage (33 kV / 132 kV)

HP – Heat Pump

ICT – Information & Communications Technology

LEM – Local Energy Market

LMP – Locational Marginal Price

LTDS – Long Term Development Statement

LV – Low Voltage (400 V)

MV – Medium Voltage (11 kV)

NETA - New Electricity Trading and Transmission Arrangements

NGESO – National Grid Electricity System Operator

NGET – National Grid Electricity Transmission

NTS – National Travel Survey

OPF – Optimal Power Flow

SM – Smart meter demand

SO – System Operator (Either DSO or TSO)

SPEN – Scottish Power Energy Networks

T-D – Transmission-Distribution

TNUoS – Transmission Network Use of System

TSO – Transmission System Operator

UK – United Kingdom

V2G – Vehicle to Grid

VPP – Virtual Power Plant

WPD - Western Power Distribution

Chapter 1:

Introduction

Since the industrial revolution, fossil fuels have been the world's primary energy source which has resulted in rising levels of carbon dioxide in the atmosphere. This has accelerated the warming of the planet by more than 1°C above pre-industrial levels [1]. In response, the United Kingdom (UK) Government has legislated to reach 'net zero' carbon emissions by 2050 [2] and measures to achieve this target include investment in low carbon heating and transport [3]. The Scottish Government energy strategy includes targets to source the equivalent of 50% of the energy for heat, transport and electricity from renewable sources by 2050 [4][1]. The implications of these targets on electricity transmission and distribution networks are significant. The predicted levels of electric vehicles (EVs) and heat pumps (HPs) required to decarbonise the UK heat and transport sectors could require substantial upgrades to the UK electricity networks, estimated as costing up to £36 billion between 2010 and 2050 in [5] and up to £48 billion by 2050 in [6]. The potential reduction in these upgrade costs has been estimated at up to £25 billion using smart EV charging, HP control and voltage regulation in [5] and up to £19 billion using smart planning and active network management techniques in [6].

The cost of managing transmission network constraints in Great Britain (GB) was £1.07 bn in the 2020/21 financial year, making up 58% of the overall system balancing cost [7]. Of these constraint costs, 21% was for wind curtailment and 54% was for gas generation to rebalance the system. Distribution network constraint costs are harder to quantify as generators don't generally receive constraint payments: developers either receive a 'non-firm' generation connection without compensation for curtailment [8], pay towards network upgrade costs to receive a 'firm' connection [9] or they do not connect

[1] In Scotland, heat and transport currently make up 51% and 25% of total energy demand respectively with electricity demand accounting for the remaining 24% [4].

due to prohibitively expensive upfront connection costs [10]. However, there is increasing focus on flexibility as an alternative to network reinforcement at distribution level and local flexibility markets have been introduced to manage distribution system constraints, with over 1 GW of capacity procured in GB in 2020 which rose to 3 GW in 2021 [11]. These markets are in their infancy, and consolidated costs for this flexibility across all GB distribution network licence areas are not readily available. However, to give some examples, UK Power Networks paid £30m for 350 MW of capacity in 2021 and to date Western Power Distribution (WPD) have contracted 456 MW of flexibility which they claim has deferred £39m of reinforcement costs in 2019/20 [12].

In Scotland, renewable energy generation has gone from supplying 8% of final energy in 2009 to 18% in 2017 [4]. This increase has been achieved predominantly through the installation of onshore wind capacity which has resulted in network capacity constraints at both transmission and distribution level [13]. For example, Figure 1-1 highlights that many grid supply points (GSPs) and extra high voltage (EHV) circuits in central and southern Scotland are operating close to their operational limits. Due to transmission capacity constraints, at times of high wind output in Great Britain (GB), National Grid Electricity System Operator (NGESO) pays wind farms upwards of £100 million in constraint payments each year [14], which has increased in recent years despite a £1.3 billion HVDC transmission network upgrade being commissioned to address the major transmission bottleneck between Scotland and England [15]. These costs highlight the significant challenge of decarbonisation to the system operator, and the opportunity for storage and a more flexible power system to reduce these costs if they can lower the costs of network investment and curtailment of renewables.

Distribution network capacity constraints are also prevalent in the Midlands, south west England and Wales, as shown in Figure 1-2, where more than half of the Bulk Supply Points (BSPs) served by Western Power Distribution (WPD) have low generation headroom due to high penetrations of DG, particularly solar PV [16]. High levels of network capacity constraints are also evident from inspection of the network capacity maps for east England [17] and northern England [18].

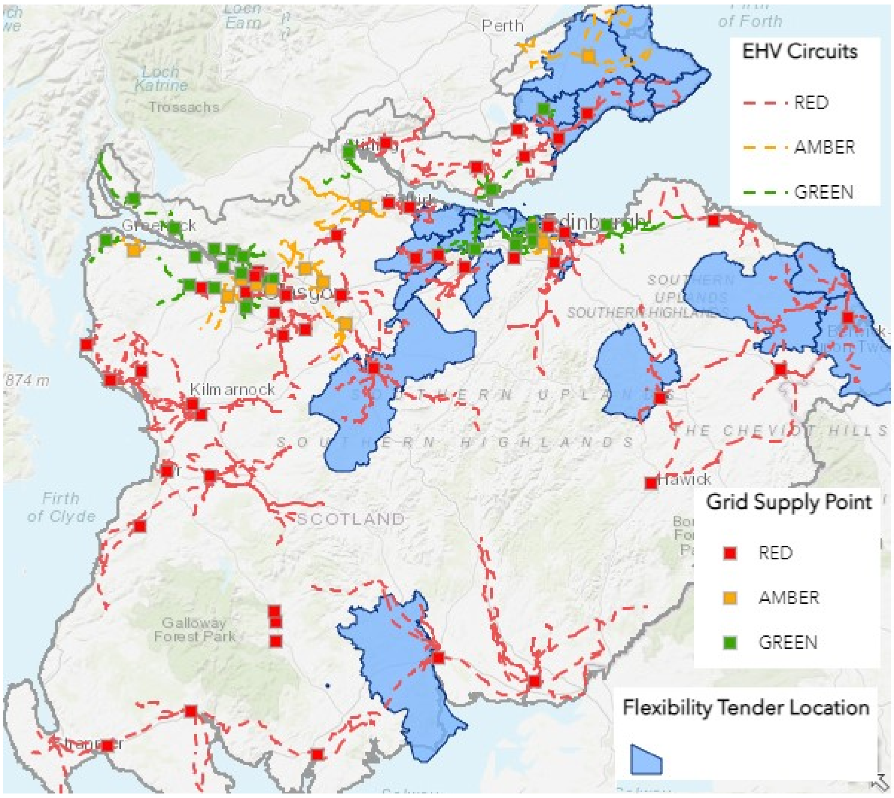

Figure 1-1: Scottish Power Energy Networks (SPEN) distributed generation heat Map [19].[2]

In GB, the winter peak heat demand has been estimated to be 170 GW [20] and around 80% of this demand is met by natural gas. The peak electricity demand in GB is around 60 GW [21] and the electricity distribution networks could require costly upgrades if called upon to meet a portion of peak heat demand. Globally, renewable electricity generation capacity has increased by 34% from 1750 GW in 2014 up to 2351 GW in 2018 [22], however renewables still only made up 10.6% of total final energy consumption in 2017 [23], with 2% coming from wind and solar combined. Hydrogen is being considered as an alternative energy carrier for heat and transport, which could transfer some of the burden on the electricity networks onto the gas networks [21], however, it remains likely that future electricity transmission and distribution systems will be heavily relied upon for the low carbon transition [24].

[2] Grid supply points (GSPs) and extra high voltage (EHV) circuits in red are categorised as having at least one operational factor (power flow capacity, voltage or fault current) close to the operational limit [19].

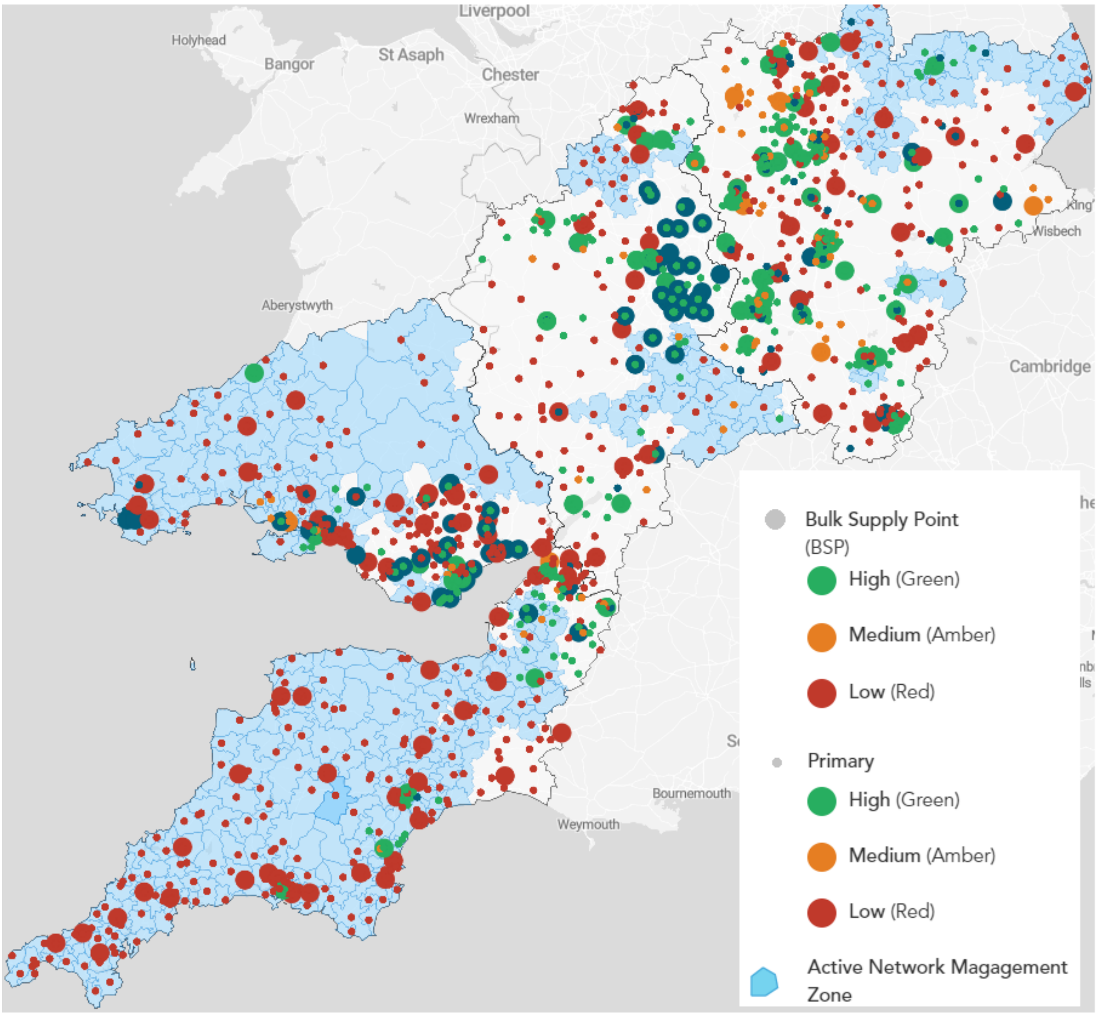

Figure 1-2: Western Power Distribution (WPD) network capacity map [25].[3]

The decentralisation of electricity supply with distributed generation (DG) is challenging the incumbent paradigm of centralised operation of electricity systems. In GB, the share of DG is anticipated to increase from 24% in 2019 up to 35-58% in 2050 [21]. Distributed energy resources (DERs) such as EVs, distributed wind generation, solar PV, HPs and battery energy storage are, to an increasing extent, replacing fossil fuel technologies in providing heat and transport [26]. This brings with it a significant challenge to the operation of electricity networks which do not universally have the capacity to meet the peak heat and transport demands currently met by fossil fuels [27]. Electricity system planners are faced with difficult infrastructure and operational investment decisions in a highly uncertain world where new DG, storage and demand technologies could

[3] Bulk Supply Ports (BSPs) with less than 5% of total site capacity available are shown in red, and those with 15% of total site capacity available are shown in green [25].

significantly change the power flows on the electricity networks [28]. Increasing DER penetrations has led to the operation of distribution networks near thermal or voltage limits known as ‘congestion’. Congestion management is being considered as an alternative to network reinforcement at distribution level and a summary of the latest research on the subject can be found in [29] and [30].

As well as being a challenge to electricity system planners, DERs such as EVs could offer flexibility for congestion management and ancillary services [31]. For example, in the areas highlighted as ‘Flexibility Tender Locations’ in Figure 1-1, local markets are being implemented to utilise DER flexibility for congestion management. Flexibility has a key role to play in reducing peak power flows, and deferring or reducing the need for network upgrades to meet these peak power flows on transmission and distribution networks [28]. DERs such as EVs, HPs and battery energy storage can offer demand side response (DSR) through load shedding and frequency response [32] and controllable DG can offer frequency response, congestion management and other ancillary services [33]. However, in most liberalised electricity markets, such as GB, the activities of transmission and distribution operation are separated, as illustrated in Figure 1-3. The future distribution system operator (DSO)[4] and transmission system operator (TSO)[5] may have to compete for the flexibility that DERs can provide to minimise operating costs and network upgrades [34]. Without sufficient coordination of access to DER flexibility between the TSO and DSO, the full value of DER flexibility in minimising overall system costs to the consumer may not be realised [35].

[4] In Europe, the term DSO is synonymous with the entity referred to in GB as DNO (distribution network operator), however, in GB the term DSO refers to the active system operator of the ‘near future'. In this thesis, the term DSO is used in the GB context where the traditional role of the DNO is extended to a more operational role in actively managing distribution networks.

[5] In GB, National Grid Electricity System Operator (NG ESO) operates the whole GB electricity transmission system and National Grid Electricity Transmission (NGET) are the transmission owner (TO) that own/maintain the transmission system in England and Wales. In this thesis, the term TSO is synonymous with entity now known in GB as the ESO.

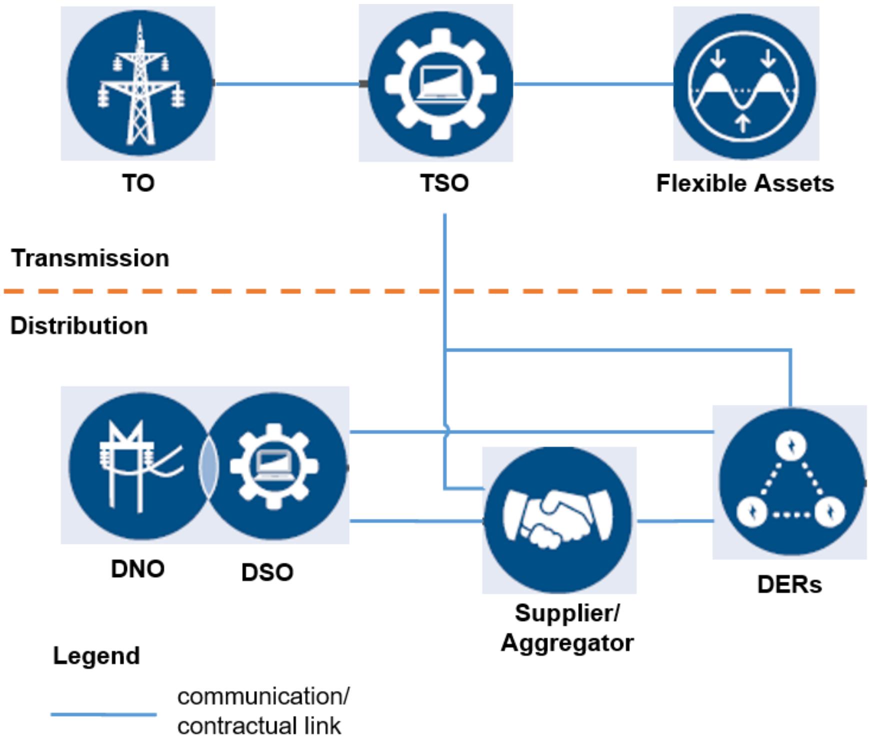

Figure 1-3: Simplified illustration of transmission and distribution system access to DERs in existing GB market arrangements. Adapted from [36].

Researchers have proposed DSO-TSO coordination schemes [37] and applied them to three European electricity systems along with a cost-benefit analysis [38]. Gaps exist in the literature in considering the compatibility of the proposed schemes with the GB electricity system, and in assessing their performance. In this thesis, novel DSO-TSO coordination mechanisms are developed, based on the schemes proposed in the literature, and compared in terms of complexity and computational performance.

DERs such as EVs are an important source of flexibility, and recent research has focused on optimisation strategies for EVs [39], [40] and flexibility market mechanisms for congestion management [41], [42]. While there has been research into EV flexibility for low voltage (LV) congestion management [43], [44], research gaps exist in developing scalable methods and in integrating these with DSO-TSO coordination mechanisms. This thesis provides a novel scalable LV congestion management scheme (CMS) to utilise flexibility, particularly from home charging of EVs, integrated with a DSO-TSO coordination mechanism.

1.1 Congestion management

Until recently, in GB and most modern power systems there has been limited requirement for coordination between the TSO and distribution network operators (DNOs) [45]. Historically, the TSO has mainly used transmission connected generation to balance supply and demand and provide ancillary services [46]. The DNO has taken a 'fit and forget' or 'copper plate' approach whereby the distribution networks are designed for worst case (such as maximum demand) scenarios with minimal active operation or congestion management [47].

In recent years, progress in information and communication technology (ICT) including distribution network monitoring equipment and metering, has made it possible for the DNO to manage networks more actively, taking the role of DSO [48]. There is increasing uncertainty in the trajectory of net demand in distribution networks due to the growth in DERs, and the potential for large demand growth with the electrification of heat and transport [21]. For these reasons, DNOs are increasingly using flexibility from DERs combined with ICT solutions and software platforms to carry out congestion management as an alternative to costly network reinforcement [49]. For example, in GB there are currently distribution level flexibility markets running in most of the DNO regions [50], such as the flexibility tender locations highlighted in Figure 1-1. Further to these flexibility markets, there are active network management (ANM) schemes in operation in many congested regions of GB distribution networks[6]. In these ANM schemes, distributed generators, often wind generators, are provided 'non-firm' connections by the DNO where they are curtailed when network export limits are reached [51].

Existing flexibility markets and ANM schemes do not currently manage congestion at LV, but with the electrification of heat and transport using HPs and EVs central to decarbonisation targets, an equivalent mechanism will be required [27], [52]. While domestic customers (connected at LV) are participating in flexibility markets [50], there are thus far no markets in operation to solve LV congestion. Researchers have studied the aggregation and optimisation of flexible resources at LV and reported voltage or current violations in [53] and [43] without managing these constraints, while in [54] and

[6] ANM was initially implemented in Orkney [136], Shetland [234] and East Lothian [13] but it has since been rolled out across GB. For example, ANM is used extensively by western power distribution (WPD) in congested areas of the midlands, South West England and Wales [25].

[39], only thermal constraints have been considered. Approaches to congestion management at higher voltages, which assume balanced phases, such as the optimal power flow methods employed in [55] and [56], are not adequate for three-phase LV networks as they are often unbalanced [57]. Furthermore, existing three-phase optimal power flow techniques, such as those presented in [58] and [59], may require too much computational overhead (processing power and time) to find a solution as the size of the network increases exponentially from higher voltages down to LV.

There are gaps in the literature in considering how LV constraints could limit participation of EVs in markets to provide services to the DSO and TSO at higher voltages. In this thesis, a tractable[7] three-phase LV CMS, is developed which can be implemented in parallel for multiple regions of electrical network and potentially scaled to millions of customers. The LV CMS is integrated with a DSO-TSO coordination scheme developed in this thesis, and an example is provided of flexibility from EV home charging being accessed by the TSO while respecting thermal and voltage limits at LV.

To date, limited analysis has been carried out of the network upgrades required for the combined electrification of heat and transport using HPs and EVs: for example, in [6] it is estimated that 32% of LV feeders across GB will require reinforcement if 40-70% of customers have 3.5 kW home EV chargers. There is therefore a need for further work in estimating the hosting capacity of LV networks with the application of 'smart' or optimised home EV charging. In this thesis, a LV CMS developed for three-phase (unbalanced) networks is applied to estimating the hosting capacity of a set of representative LV networks for HPs and optimised home EV charging. This provides an assessment of the adequacy of existing representative LV networks for the net zero transition, and when integrated with a DSO-TSO coordination mechanism, provides an indication of the level of flexibility from EV home charging available to the DSO and TSO at higher voltages.

[7] In this thesis, tractable is defined at LV level as the capability of solving multi-period optimisation at 10-minutely intervals for a 24 hour period on a desktop computer in less than a minute for a sizeable LV network of 1000 nodes and 400 domestic customers.

1.2 DSO-TSO coordination

In parallel to the DNOs in GB moving towards actively managing the distribution system, the TSO is also taking an increasing interest in flexibility from DERs[8]. Distribution connected batteries, and other DERs are increasingly providing frequency response and reserve services to NGESO [46]. Furthermore, the 'aggregator' or virtual power plant (VPP) is becoming a key market player in providing balancing and ancillary services to the TSO by aggregating flexibility from multiple DERs [60][9]. Where previously the TSO managed transmission assets and the DNO passively managed their networks, this is no longer the case. Both the DNOs and TSO are now accessing DERs[10] and if this trend is to continue there will be a need to coordinate these activities to prevent conflicting outcomes and to prioritise access. The TSO will benefit from accessing DER flexibility to provide system balancing services and ancillary services such as frequency response, reserve and black-start [61]. DNOs must ensure safe operation of their networks, and will benefit by accessing DER flexibility to defer network reinforcement [62].

There are many potential market routes for the DSO and TSO to access DERs, including long term ancillary service contracts and short-term balancing markets. There will be a need to coordinate between the DSO and TSO in accessing and activating DERs through all these market mechanisms [63], particularly when DERs are located in congested regions of distribution networks. This thesis will not consider the coordination of all market mechanisms which is considered too broad in scope, but instead it will focus on developing DSO-TSO coordination models for system balancing and congestion management. The models developed in this thesis are to be compatible with electricity market operation and trading arrangements in GB which are summarised in Appendix A. It is recognised that the DSO does not necessarily need to

[8] NGESO added a distributed resource desk in January 2019 to enable faster instructions to be issued to smaller DERs participating in the balancing mechanism [235].

[9] GBs largest VPP managed by Flexitricity exceeded 500 MW capacity in June 2020 [236]. Flexitricity operates in the balancing mechanism and provides ancillary services to the TSO.

[10] Four of GBs DNOs are procuring flexibility from DERs for congestion management using the 'Flexible Power' market platform [71]. At the time of writing, WPD have contracted 440 MW of flexibility through the platform and Scottish and Southern Electricity Networks are calling on distributed generators to register their interest in supplying 250 MW of flexibility [237].

balance supply and demand within the distribution network, but the TSO must do so at a system wide level. Therefore, in the context of this thesis, DER flexibility is used by the DSO to solve distribution level constraints, and the TSO may use it to both solve transmission level constraints and correct any imbalances in supply/demand.

1.3 Research aims and contributions

Electricity distribution networks will be studied with high penetrations of DERs in the context of the net zero transition, while considering compatibility with existing market arrangements. The research work to be presented in this thesis addresses the following research questions:

1. How can access to distributed flexibility be coordinated between the DSO and TSO for system balancing and distribution system congestion management?
2. How can distribution system congestion management be scaled and coordinated with the TSO for millions of flexibility providers down to LV level?

To answer these questions, DSO-TSO coordination schemes and congestion management methodologies are developed to be compatible with deregulated electricity market structures, in particular that of the GB electricity system. The performance between coordination models is compared and priority of access to DERs between the TSO and DSO is considered. Finally, a scalable LV network CMS is integrated with a DSO-TSO coordination scheme to manage congestion at all voltage levels.

According to the above research questions, the following contributions are made in this thesis:

1. State-of-the-art DSO-TSO models from [37] are compared in terms of complexity, compatibility with existing systems and access to DER flexibility. The most promising DSO-TSO coordination models for high levels of DERs are identified as the *Local market* and the *decentralised Common market (*referred to as the *Decentralised market)*.
2. Novel implementations of the *Local market* and *Decentralised market* DSO-TSO coordination models are developed, and the *Local market* is demonstrated to be superior to the *Decentralised market* in terms of lower complexity, better tractability, and improved compatibility with existing GB TSO balancing market operation**.**

3. A novel and scalable LV congestion management scheme (CMS) is developed and integrated with the *Local market* DSO-TSO coordination scheme to allow access to EV flexibility down to household level while respecting LV network constraints. By applying the LV CMS to five LV networks, the hosting capacity for EVs is more than doubled on three of the networks compared to uncoordinated EV charging.

1.4 Publications

In this section, publications arising from the results of this thesis are listed along with associated papers relating to concepts and tools used in this thesis.

Journal papers

C. Edmunds, S. Galloway, I. Elders, W. Bukhsh, R. Telford, Design of a DSO-TSO balancing market coordination scheme for decentralised energy. *IET Generation Transmission Distribution. Volume 14, no. 5, pp. 707-718, 2020.*

C. Edmunds, S. Galloway J. Dixon, W. Bukhsh, I. Elders, Hosting capacity assessment of heat pumps and optimised electric vehicle charging on low voltage networks. *Applied Energy*. *Volume 298, 2021.*

Associated journal papers

C. Edmunds, S. Martín-Martínez, J. Browell, E Gómez-Lázaro, S. Galloway, On the participation of wind energy in response and reserve markets in Great Britain and Spain. *Renewable and Sustainable Energy Reviews*. *Volume 115, 2019.*

W. A. Bukhsh, C. Edmunds, & K. R. W. Bell, OATS: Optimization and Analysis Toolbox for Power Systems. *IEEE Transactions on Power Systems*. *Volume 35, no. 5, pp3552-3561, Sept 2020.*

J. Dixon, W. Bukhsh, C. Edmunds, K. R. W. Bell, Scheduling Electric Vehicle Charging to Minimise Carbon Emissions and Wind Curtailment. *Renewable Energy*, *Volume 161, 2020.*

Associated conference proceedings

C. Edmunds, I. Elders, S. Galloway, B. Stephen, A. Postnikov, L. Varga, Y. Hu, T. Kipouros. Congestion management with aggregated delivery of flexibility using distributed energy resources. *6th IEEE International Energy Conference (ENERGYCon), Gammarth, Tunisia, 28th September – 1st October 2020.*

C. Edmunds, D. Frame & S. Galloway, Distributed Electricity Markets and Distribution Locational Marginal Prices: A Review. *Universities Power Engineering Conference (UPEC), Heraklion, 28th-31st August 2017*.

C. Edmunds, D. Frame & S. Galloway, Lessons Learned from Local Energy Projects in Scotland. *CIRED Workshop, Ljubljana, 7th-8th June 2018.*

C. Edmunds, W. Bukhsh & S. Galloway, The Impact of Distribution Locational Marginal Prices on Distributed Energy Resources: An Aggregated Approach. *European Electricity Markets (EEM). Łódź, 27th -29th June 2018.*

C. Edmunds, W. Bukhsh, S. Gill & S. Galloway, Locational Marginal Price Variability at Distribution Level: A Regional Study. *Innovative Smart Grid Technologies (ISGT), Sarajevo, 21st – 25th October 2018.*

A. Postnikov, C. Edmunds, J Nieto-Martin, T. Kipouros, Y. Hu *et. al.*, Aggregators as digital intermediaries to local electricity markets. *Energy Evaluation Europe, London, 29th June – 1st July 2020*.

Associated technical reports

C. Edmunds, S. Gill, South West England network analysis, report for Centrica local energy market, August 2017.

1.5 Thesis Overview

The remainder of this thesis is organised as follows:

- **Chapter 2** contains a literature review of the state of the art DSO-TSO coordination models in. Several coordination models are assessed in terms of compatibility with existing system operation of European deregulated electricity markets.
- **Chapter 3** develops three selected coordination models and develops them further along with optimal power flow formulations. The DSO-TSO coordination schemes are developed to allow the TSO to access flexibility from DERs for system balancing and the DSO to manage distribution level congestion.
- **Chapter 4** contains case studies used to assess and compare the three DSO-TSO coordination models developed in chapter 3 in terms of balancing costs, computational efficiency, and tractability. A three-bus transmission model provides a simple benchmarking of the models and a transmission-distribution

network model of Cornwall in the south west of England allows comparison on a larger distribution network.

- **Chapter 5** develops a tractable three-phase LV congestion management scheme is developed to manage flexibility down to household level.
- **Chapter 6** presents case studies for the LV congestion management scheme which is used to determine the network hosting capacity for the electrification of heat and transport for a set of representative LV networks.
- **Chapter 7** provides an example of the integration of the LV congestion management and DSO-TSO coordination schemes as well as consideration of the flexibility available over a 24 hour period.
- **Chapter 8** provides conclusions and future work for both the DSO-TSO coordination and LV congestion management schemes.

Chapter 2:

Literature Review

Building on the concepts available in the literature, this thesis addresses the problem of DSO-TSO coordination and distribution network congestion management, including the prioritisation of access to DERs between the DSO and the TSO to ensure reliable system operation. The role of 'aggregator' has been identified as a key function in providing a route to market for smaller DERs [64] and will play a central role in providing flexibility to the DSO and TSO [65].

A detailed literature review is presented in this section that covers existing electricity distribution network operation, the 'state of the art' in DSO-TSO coordination models and distribution level congestion management techniques. This motivates the selection of the most suitable models for further development in this thesis.

2.1 Existing distribution network operation

Historically, distribution networks have been designed to passively transport power in one direction between transmission networks to households connected at LV, as illustrated in Figure 2-1. In this passive operating model, there is limited customer involvement, networks are sized to meet peak winter demand and there is limited network observability or control of DERs [66]. Conventional planning methodologies used by DNOs have used static network limits, with no real-time network measurement, which has resulted in conservative network capacity limits for new DER connections [67].

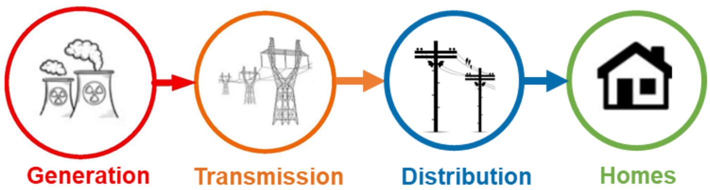

Figure 2-1: Passive distribution system illustration; adapted from [68].

The passive role of DNOs is evolving due to increasing volumes of DER connections and the electrification of heat and transport. Increased DG penetration is resulting in reverse power flows from distribution to transmission as well as network congestion. Active network management (ANM) and flexibility from DERs including battery storage systems, EVs and demand response are being employed to manage these power flows (see Figure 2-2). The scale of this change is enabling DNOs to take a more 'active' role in system operation [49], transforming their role to that of a DSO.

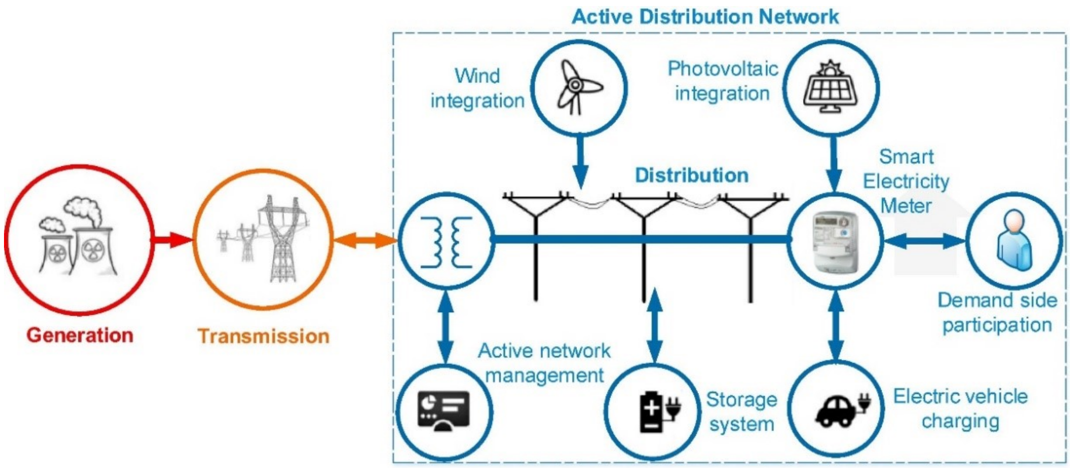

Figure 2-2: Active distribution system illustration; source: [68].

In the incumbent GB electricity structure, illustrated in Figure 2-3, the DNO's main commercial activity is levying connection charges (from new DG or demand customers) and network use of system charges.

The DNO can curtail DG output in ANM schemes to manage distribution network constraints, and large DG and transmission level generators are re-dispatched by the TSO in the balancing mechanism[11] to manage transmission network constraints. The vast majority of households passively purchase power from suppliers in the retail market and home generation such as solar PV is connected behind the customer's meter and not monitored by the DNO. Up until fairly recently, there were no markets to actively manage distribution network congestion and the DNO would carry out network reinforcement if new demand or generation connections could result in congestion.

[11] More detail on the GB electricity system, including balancing services, wholesale and retail markets, can be found in Appendix A.

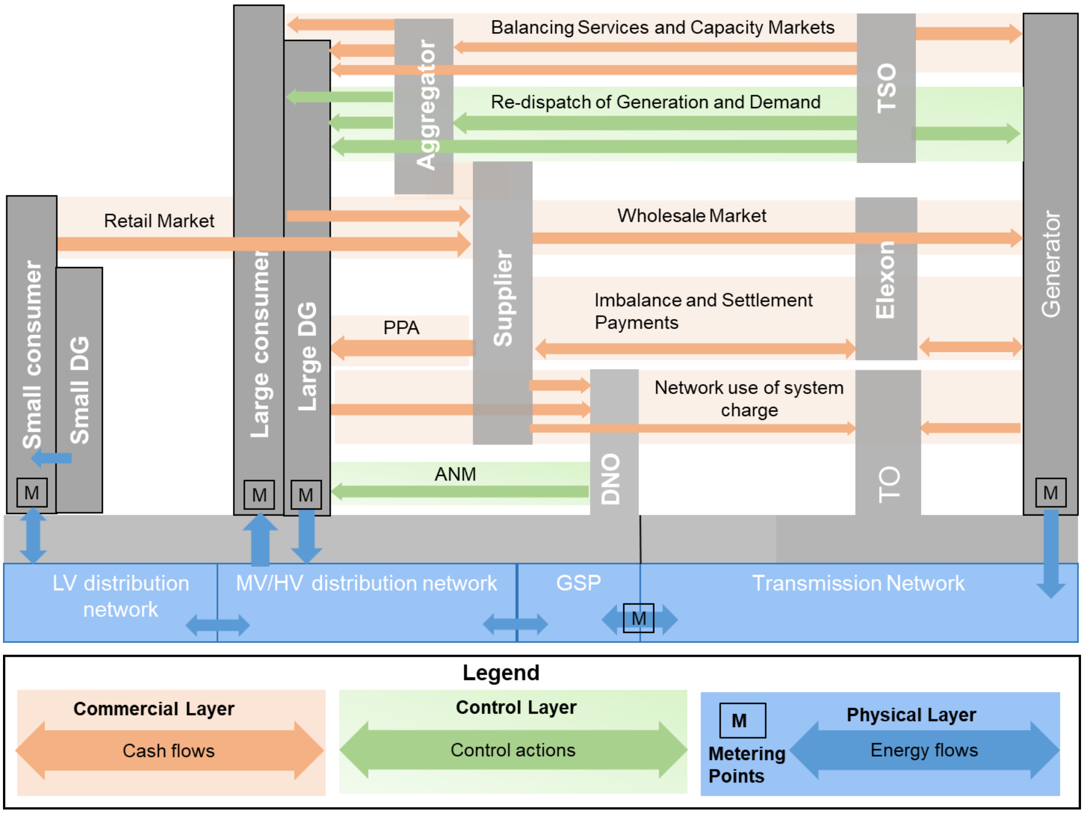

Figure 2-3: GB Electricity system incumbent archetype; source: Damien Frame [69].

The GB gas and electricity regulator (Ofgem[12]) are mandating a shift towards a 'smart and flexible energy system' [70] leading to local flexibility market trials taking place in many parts of the UK. In these trials, DSOs are procuring flexibility from DERs [71], including aggregated flexibility from households [72], to manage network congestion. Advances in ICT are enabling the utilisation of distributed flexibility and increasing the communication and cash flows between prosumers (consumers who also produce energy), aggregators, DSOs and local flexibility market operators.

2.2 DSO-TSO coordination

DSOs are increasingly accessing DER flexibility in local markets [71], meanwhile TSOs are contracting with resources connected to the distribution system, to provide services such as frequency response and reserve [73]. With increasing levels of DERs, it is essential to manage the impact that dispatch of DERs by the TSO can have on the distribution networks [74]. Furthermore, there is potential for conflicts between the DSO and TSO in their objectives, which presents a requirement for coordination between

[12] Office of Gas and Electricity Markets. https://www.ofgem.gov.uk/.

transmission and distribution [34], [75]. For example, in [47] several concerns are raised as to the interaction between the DSO and the TSO, including automated actions under ANM, operated by the DSO, undermining balancing actions by the TSO.

DSO-TSO coordination is a relatively new research topic with a limited number of published works. High-level DSO-TSO coordination models have been proposed in academia [76] and in industry [36], but there is uncertainty around which of these should be adopted and how DERs will be managed in the future. With this in mind, high-level DSO-TSO coordination models[13] from GB, Europe and North America are assessed for compatibility with existing GB market arrangements; related work containing more detailed modelling is explored in depth; and finally, state-of-the-art industrial projects involving coordination between the DSO and TSO are presented.

2.2.1 High-level DSO-TSO coordination models

In recent years, significant progress has been made in proposing models and architectures for the coordination of the DSO and TSO [34], [38]. In GB, high-level system architectures for DSO-TSO coordination, termed ‘Future Worlds’, have been proposed by the Energy Networks Association (ENA) [36]. In North America, the Future Electric Utility Regulation (FEUR) report on ‘Distribution Systems in a High Distributed Energy Resources Future’ [74] provided one of the seminal works on the allocation of responsibilities between the DSO and TSO, and in Europe the SmartNet models [76] [63] are the most widely cited academic work in this area. These high level models are summarised in the following sections.

2.2.1.1 ENA future worlds DSO-TSO coordination architectures

The ENA ‘Open Networks’ project provides a framework for the transition towards the ‘smart grid’ where distribution networks are actively managed [77]. This includes the introduction of flexibility markets at distribution level to provide an alternative to network reinforcement as a result of the growth in demand and DERs. The ENA provide guidance for the DSO in their role as a neutral market facilitator (NMF) [78] and market platforms for the DSO to procure flexibility are being implemented in the major DSO market trials currently taking place in GB [71], [79], [80]. They also recommend that the NMF should ensure optimal use of DERs and that decisions for procurement and

[13] These high-level models define the roles and interactions of the DSO, TSO and DERs but do not provide detailed implementations and mathematical formulations.

dispatch are transparent and open. As part of the Open Networks project, the following 'Future Worlds' architectures are provided for the coordination of DER flexibility markets between the DSO and TSO [36]:

- World A: DSO coordinates – the DSO acts as the NMF for all DERs and provides services to the TSO. Power flows between distribution and transmission are based on a pre-defined schedule agreed with the TSO.
- World B: Co-ordinated DSO - TSO procurement and dispatch of DERs. No detail is provided of how this would be coordinated except that it must be done in a transparent manner that provides the 'most efficient outcome' for consumers.
- World C: Price driven flexibility – energy price and network signals are used to vary the demand or generation from DERs. Coordination between DSO and TSO markets in World C would be similar to World B and no further detail is provided on how this could be implemented.
- World D: TSO coordinates – the TSO procures and activates flexibility from DERs, and the DSO provides their flexibility requirements to the TSO. The DSO has operational responsibility for their networks and must work with the TSO to provide efficient network operation.
- World E: Flexibility coordinator(s) – National or regional third parties act as NMF(s) for flexibility markets for the TSO and/or DSO. The NMF must provide coordination of the requirements of the DSO's and TSO.

The Future Worlds provide a useful introduction to the actors (DSOs, TSO, NMFs and other third parties) involved at GB level and their potential future roles under different market arrangements. However, they are focused on commercial arrangements and lack any clarity on technical coordination between the DSO and TSO. These architectures are not referenced further in this thesis as they lack sufficient detail or analysis on their possible implementation. They have features in common with the FEUR and SmartNet models which provide a clearer division of responsibilities between the DSO and TSO and a better starting point for model development.

2.2.1.2 Future Electric Utility Regulation DSO-TSO coordination models

In the FEUR report [74] different DSO-TSO coordination models are proposed from a North American perspective, with varying levels of involvement of the TSO and DSO in managing the distribution networks. Figure 2-4 summarises the functional entities for a high-DER electric system where the roles of distribution owner (DO)[14] and DSO are separated. In GB, the DSO role could become separate from that of the DNO, in the same way that the TSO (NGESO) and TO (National Grid Electricity Transmission) are separate legal entities at transmission level. In this case, effective communication and coordination between the DSO and DO would be essential for effective network operation and planning.

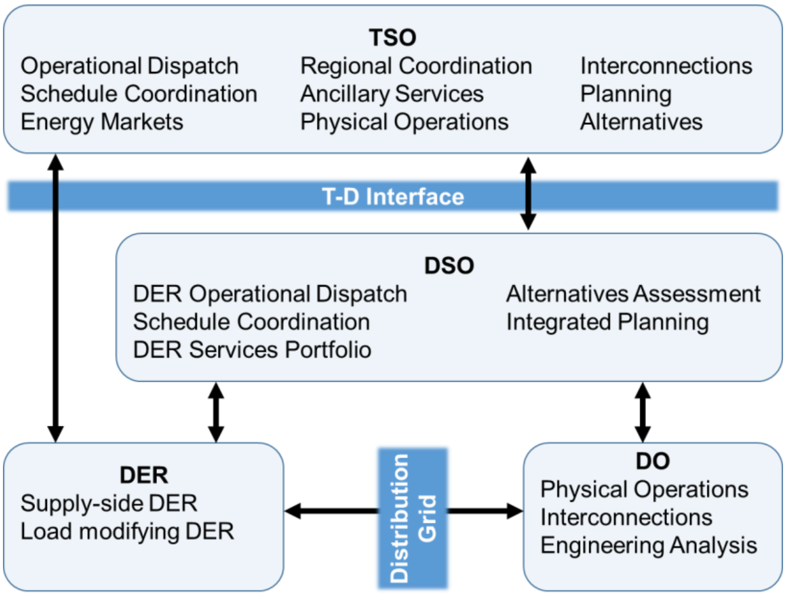

Figure 2-4: High DER integrated system functional entities; source: [74].

The following three high-level models are proposed for allocation of responsibility between the DSO and TSO across the T-D interface:

A. **Total TSO** - The TSO controls and operates the electricity system including distribution level and optimises dispatch of DERs above a low size threshold.
B. **Minimal DSO** - The TSO optimises dispatch of DERs but does not model the distribution system beyond the T-D interface. The DSO then has responsibility for validating the TSO's dispatch with communication between the DSO and TSO, TSO and DERs as well as the DSO and DERs.
C. **Market DSO** - In this model the DERs are aggregated to a minimum size (e.g., 10 MW) which means the DSO is responsible for coordination of the DER aggregators within each distribution network and responding to dispatch instructions from the

[14] Equivalent to the passive DNO role in the GB electricity system.

TSO. Within the **Market DSO** model there are two approaches to aggregation of DERs:

- C1: the DSO coordinates DER aggregators to ensure TSO dispatch is within distribution network operating limits.
- C2: the DSO carries out all coordination and aggregation within each local distribution area, providing the TSO with a single aggregated resource at each T-D interface.

The distinction between the Minimal DSO (B) and Market DSO (C1 & C2) models in terms of their participation in the wholesale markets are shown in Figure 2-5. The dashed green line labelled B represents the Minimal DSO where DERs participate directly in the wholesale market (Independent System Operator – ISO - market)[15], whereas in the dashed green line labelled C1 represents the Market DSO C1 model where DER aggregators participate in the wholesale markets, and finally the solid green line labelled C2 represents the Market DSO C2 model where all DER participation in wholesale markets is through the DSO. In the Total TSO model, Figure 2-5 would be significantly simplified in that the operations within the DSOs remit would become part of the TSOs economic dispatch (within the ISO market in North American wholesale markets) and the need for coordination between the DSO and TSO would largely be removed. In this case the DSO would not be involved in distribution level markets shown in Figure 2-5.

[15] In most North American markets, wholesale market clearing is centralised and operated by an ISO. For example, refer to the Californian ISO (CAISO) market: http://www.caiso.com.

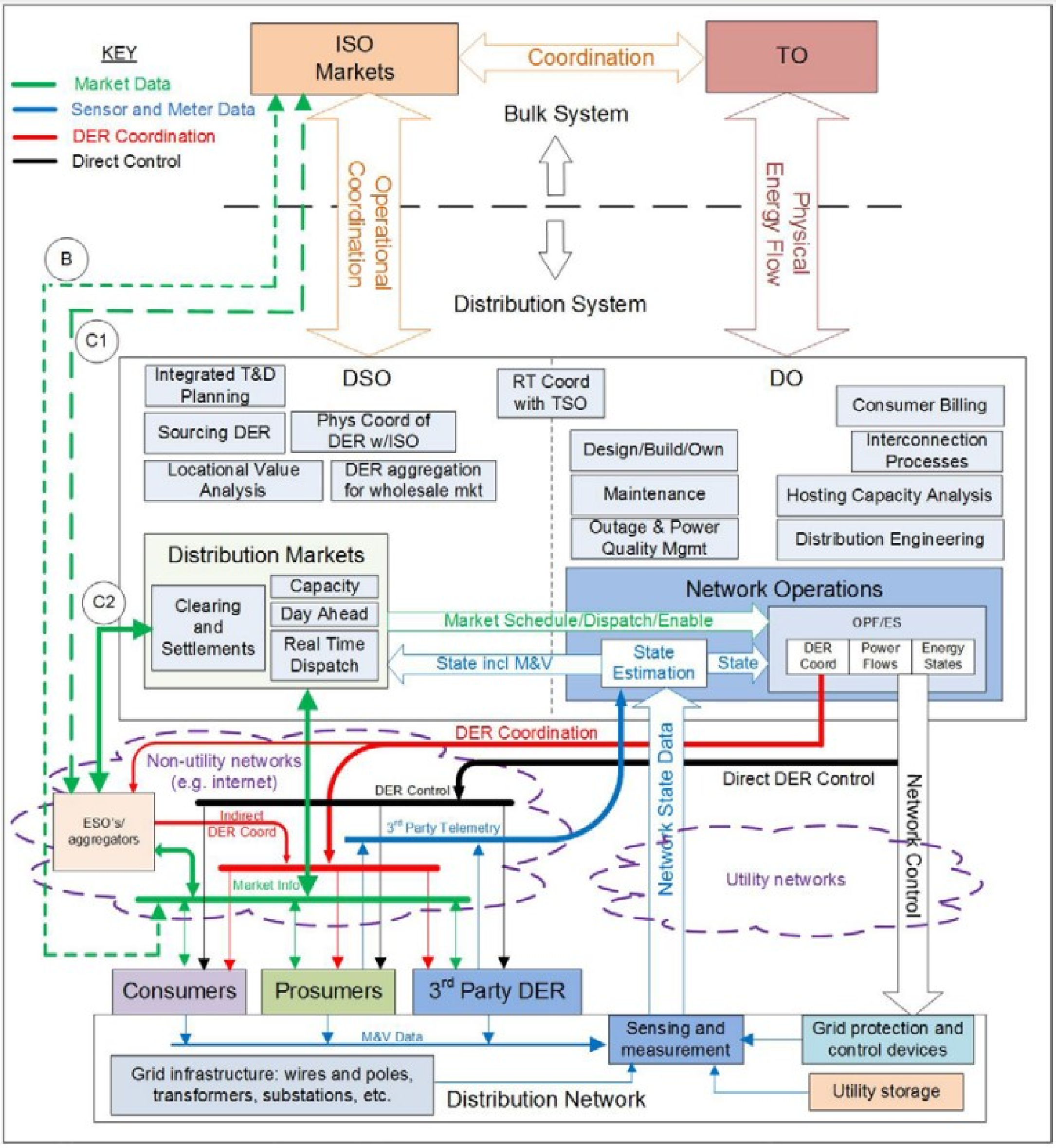

Figure 2-5: Functional entities and data flow in a high DER system. source [74].

Some of key points raised by the authors of the FEUR report with respect to DSO-TSO coordination are as follows:

1. The **Total TSO** model is not recommended due to the complexity of a single large optimisation and sub-optimal division of roles between the DSO and TSO. It is instead recommended that the DSO coordinates DER schedules to ensure 'safe and reliable' operation of the distribution grid.
2. The **Minimal DSO** model requires real-time communication and operational procedures between the DSO and TSO.

3. In the **Minimal DSO** model, the DSO can procure distribution grid services from DERs that may also be participating in wholesale markets.
4. It is recommended that dispatch priority should be ‘non-discriminatory’ and should allow the DSO to maintain ‘safe, reliable operation’ of the distribution grid. Furthermore, the DSO and TSO should coordinate to ensure ‘reliable operation of the *integrated grid*’.
5. The **Market DSO** model C2 is reported to be a simplification on the C1 model. In the C2 model, DER aggregators do not participate directly in the wholesale markets, whereas in the C1 they do. However, the C2 model requires the DSO to provide a single aggregated resource to the TSO at each T-D interface.

To expand on these key points raised in the FEUR report, further work is required in defining the communication and operational procedures between the DSO and TSO, in particular the process required for the TSO market to reach a solution acceptable to the DSO. If DERs are both participating in wholesale markets and providing services to the DSO, this raises an important question of how access to these DERs should be prioritised between the DSO and wholesale markets. Finally, further work is needed to define how the DSO can aggregate DERs, which can have differing prices and locations on the distribution network, into a single resource to the TSO in a ‘non-discriminatory’ fashion.

2.2.1.3 SmartNet DSO-TSO coordination models

In the European Union SmartNet project [61], [63], an ‘Integrated Reserve’ market architecture is proposed to maximise the delivery of ancillary services and congestion management from DERs to both the transmission and distribution grid. In the proposed architecture (illustrated in Figure 2-6), network models can be integrated with market clearing, and devices (such as DERs) can be aggregated and bid into the market and then disaggregated for dispatch.

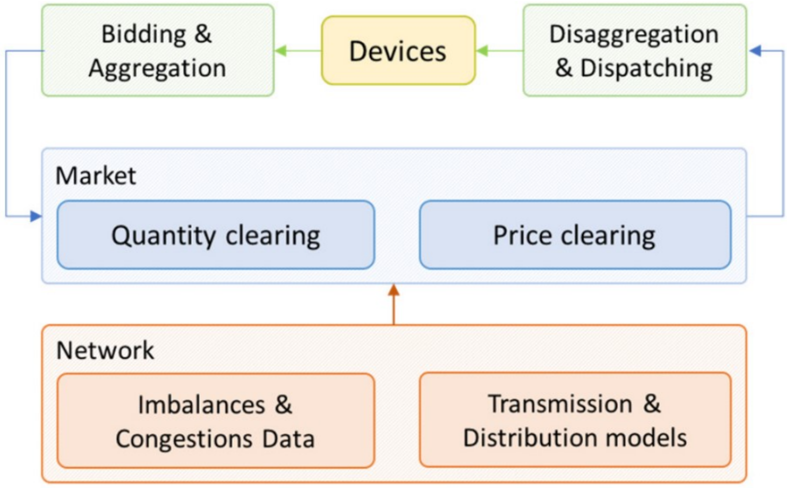

Figure 2-6: SmartNet integrated reserve architecture; source [37].

Within the SmartNet market architecture, five coordination schemes are proposed which provide options for the roles and coordination of the DSO and TSO in terms of network operation, market clearing and control and communication with DERs.

The five DSO-TSO coordination schemes are summarised as follows:

1. *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 congestion at distribution level.
2. *Local market*: the DSO operates a distribution level market; clears services and transfers them to the TSO operated market.
3. *Shared balancing responsibility*: the DSO has balancing responsibility for the distribution grid while the TSO has balancing responsibility for the transmission system. This is the only scheme where the TSO has no control over DERs.
4. *Common DSO-TSO market*: distribution constraints[16] are included in market clearing. Either in a *Centralised* optimisation process for entire T-D system (TSO and DSO jointly operate) or with separate DSO markets run first (*Decentralised*).
5. *Integrated flexibility*: TSO, DSO and third parties all bid for flexibility in a common market.

The schemes can be grouped into centralised and decentralised approaches (see Figure 2-7). In the centralised approaches, market clearing and dispatch of DERs is carried out by a central market operator (usually the TSO). In decentralised

[16] Limits to safe network operation, such as voltage and thermal limits.

approaches, separate markets run locally by the DSO which dispatch DERs, and in some cases these markets can bid in to the TSO market.

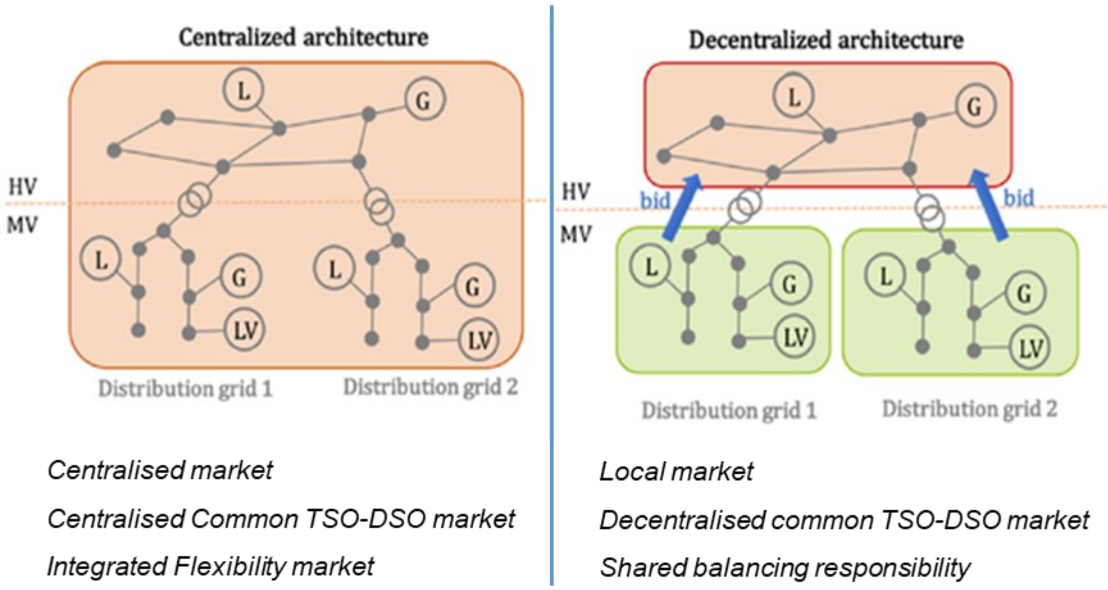

Figure 2-7: SmartNet centralised and decentralised market structures; source: [37].

Figure 2-8 shows the high level information flows between the market actors in the SmartNet models including market bids, prequalification and aggregation of DER flexibility.

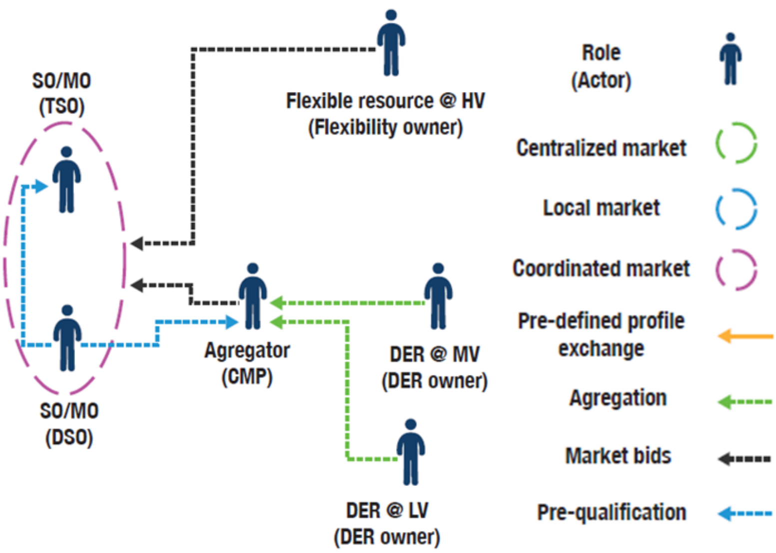

Figure 2-8: Smartnet DSO-TSO market actors (for the Common DSO-TSO coordination model). See [81] for illustrations of all SmartNet models.

In [38], four of the SmartNet schemes have been simulated in three European countries (Italy, Spain and Denmark), where the total costs for frequency restoration reserves

(FRR)[17] are compared. In this thesis, coordination schemes are developed to provide reserve in the GB balancing mechanism (2-90 mins timescales) and emphasis is placed on assessing complexity and computational tractability.

Further detail on each of the five SmartNet models (highlighted in *italic*) is provided below including discussion of commonalities, and important differences, between these and the FEUR models (highlighted in **bold**).

Centralised market

In both the *Centralised market* and **Total DSO** models, the TSO is responsible for dispatching DERs. In the **Total TSO** model, the TSO also manages distribution network congestion, whereas in the *Centralised market*, the TSO does not generally consider distribution level constraints. In exceptional cases the distribution network constraints could be included in the TSO market clearing of the *Centralised market* [76], in which case the *Centralised market* and **Total TSO** models converge.

The **Minimal DSO** model is very similar to the SmartNet *Centralised market*. In both models, the TSO controls DERs, but the DSO must coordinate (or prequalify) the dispatch of DERs to prevent distribution network constraints. One subtle difference is that, in the **Minimal DSO** model the DSO also procures flexibility from DERs, adding further complexity, whereas in the *Centralised market* the DSO does not procure flexibility from DERs and instead the DSO can be involved in ‘system prequalification’ prior to market clearing, where the DSO can block DER activation on a specific area of distribution network, if deemed to cause network constraints. The DSO can also be involved in validating the results of the TSO market clearing, with the potential for multiple iterations of market clearing until the DSO approves the result of the TSO market.

Local market

In the *Local market,* the DSO dispatches DERs in a separate market to solve distribution network congestion and clears DER positions for participation in the TSO market. Importantly, in the *Local market* it is proposed that the DSO has priority in using flexible resources from the local distribution network. The TSO then has access to the flexibility remaining after the local market. The *Local market* model does not have an

[17] FRR are needed to restore system frequency to nominal by responding to instructions to increase or reduce energy production/consumption within 2 min [14].

exact equivalent FEUR model as in the **Market DSO** models, the DSO aggregates DERs for dispatch by the TSO rather than operating its own market.

Shared balancing responsibility

The *Shared balancing responsibility* model has no equivalent in the FEUR models. The DSO is assigned balancing responsibility for the distribution network and a pre-defined schedule of power flow is defined between each Transmission-Distribution (T-D) interface. The TSO has no access to flexibility from DERs in this model which are solely available to the DSO.

Common DSO-TSO market

In the *centralised Common DSO-TSO market*, the DSO and TSO jointly run a single central optimisation that includes distribution constraints. This is equivalent to the FEUR **Total TSO** model, except that the DSO runs the market jointly with the TSO. In the *decentralised Common DSO-TSO market*, the DSO aggregates DER flexibility which is dispatched as a result of a combined optimisation of the flexibility requirement of both the TSO and DSO.

Integrated Flexibility market

The *Integrated Flexibility market* involves the DSO, TSO and other commercial market participants competing for flexibility in a common market run by a neutral market operator. Contrary to most European wholesale power exchanges, grid constraints are proposed to be integrated into the common market clearing. There is no priority to the DSO or TSO over commercial actors in accessing flexibility in the *Integrated Flexibility market* model: flexibility is allocated to the highest bidder.

2.2.2 Academic literature on DSO-TSO coordination

This section presents a review of the existing academic literature assessing the high-level models already described along with alternative models.

2.2.2.1 Application of the SmartNet models to a 3-bus transmission network

The work of Papavasiliou & Mezghani in [56] applies the SmartNet co-ordination schemes to a system balancing problem on a 3-bus meshed transmission network connected to three identical radial distribution networks (see Figure 2-9). It is one of the few academic papers comparing DSO-TSO coordination models in any technical depth, including optimisation formulations, network modelling and balancing costs.

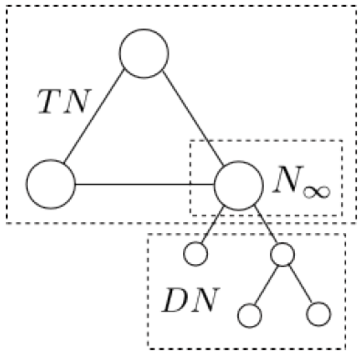

Figure 2-9: 3-bus transmission-distribution test network. Source: [82]*. DN* refers to a set of distribution nodes connected to transmission node *TN*.

The paper provides optimisation formulations and balancing costs on a test network for all the SmartNet coordination models except the *Integrated Flexibility market*. Thus, it includes:

- *Centralised Common TSO-DSO market*
- *Decentralised Common TSO-DSO market*
- *Centralised Ancillary Services market*
- *Local Ancillary Services market*
- *Shared balancing responsibility market*

In the *centralised Common DSO-TSO market,* a single optimisation of the entire T-D system is used to dispatch DERs. Linearised power flow equations are applied to the transmission network while a Second Order Cone Programming (SOCP) convex relaxation [83] is applied to the distribution system. The linearised transmission power flow equations are applied to all the coordination models while the SOCP equations are applied when the distribution network constraints are modelled (in all but the *Centralised Ancillary Services market).*

In the d*ecentralised Common DSO-TSO market*, a ‘residual supply' function is calculated based on the change in objective function with a change in power flow between T-D. To reduce the computational burden of calculating a detailed residual function, the authors propose a linear function. There is a trade-off between the accuracy of the residual function which affects the accuracy of the overall optimisation, and the computational requirements to calculate and communicate the residual function. This is an area that could be further explored in the development of a d*ecentralised Common DSO-TSO market* model.

In the *Centralised DSO-TSO market* the TSO can access DERs but does not model distribution constraints. The process of DER prequalification is not modelled and is assumed to have already taken place. In the case study considered in the paper, distribution constraints (such as thermal and voltage limits) do not limit the reserve capacity available from DERs. However, in the case of high DER penetrations and binding distribution constraints, prequalification and/or DSO validation of TSO market results would need to be considered in more detail.

In the *Local market* the DSO market clears first with half of the reserve capacity allocated to the DSO. The TSO then has access to the other half, which is the more expensive half due to the DSO already accessing the cheaper half. There is potential for refining this approach and in further development of the *Local market,* other options for allocation of flexibility between the DSO and TSO should be considered. For example, the DSO can have priority in accessing DERs to solve distribution constraints, however any remaining flexibility (not just half) can be available to the TSO.

In the *Shared balancing responsibility* market, the balancing costs are higher due to the TSO not having access to distribution network reserves. Assigning a suitable T-D schedule is not resolved in any detail in the paper (aside from assuming the T-D schedule would be obtained from results of a forward market).

2.2.2.2 Traffic light concept framework for DSO-TSO coordination

The German Association of Energy and Water Industries' (BDEW) ‘traffic light' concept [84], illustrated in Figure 2-10, provides a useful 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 traffic light scheme could be applied within the SmartNet *Local market* model to allocate flexibility between the DSO and TSO depending on the network state.

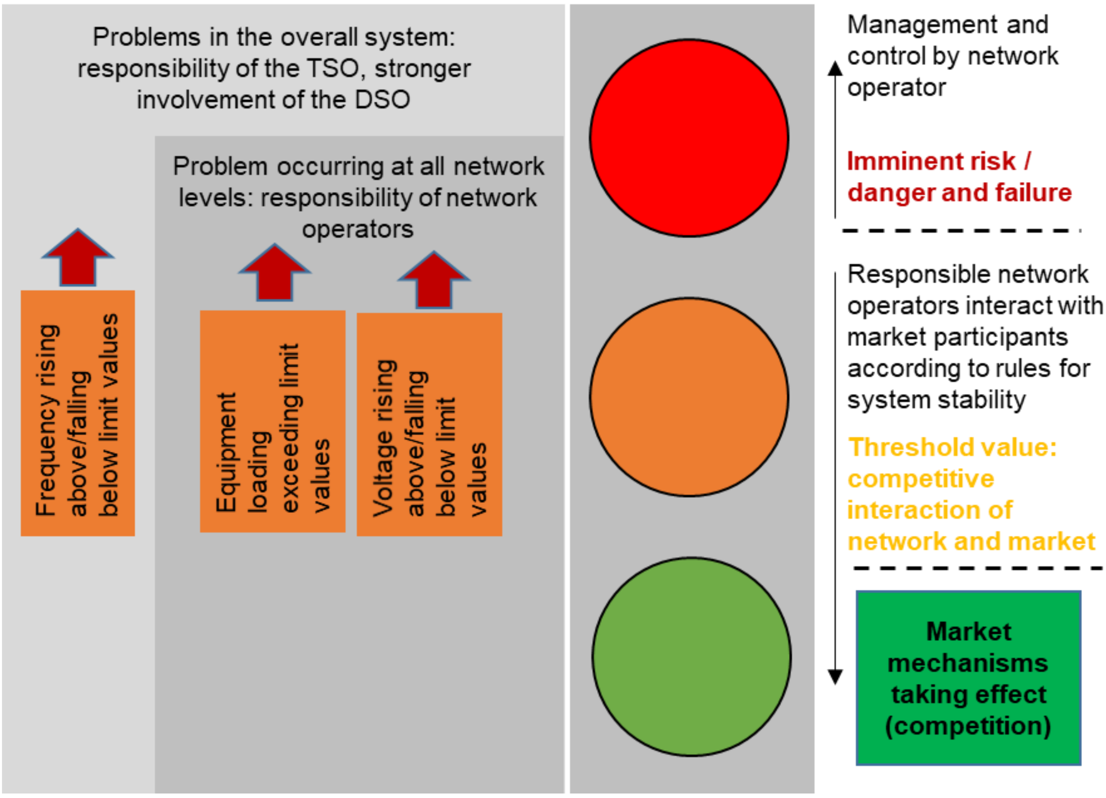

Figure 2-10: BDEW traffic light concept; source: [84].

The traffic light concept has been discussed in several other works including: [34] where DSO-TSO cooperation in each system state (green/amber/red) is considered but not demonstrated; [85] and [86] where implementations are outlined without any test case demonstrations; [87] and [88] where implementations are demonstrated at LV but with limited consideration of DSO-TSO interaction. In [89] a local flexibility market model (described in more detail in [90]) is designed, and uses the traffic light concept. A Balancing Responsible Party (BRP)[18] is modelled, with a balancing position in the wholesale market, which competes with the DSO for DER flexibility (provided via an aggregator). The traffic light application in [89] provides a useful formulation of the priorities of access to DERs in the different grid states (red, amber, green), in particular

[18] A balancing responsible party (BRP) is a market participant (such as a supplier, owner of generation assets or third party) with contractual responsibility for managing supply and demand within their portfolio. In GB, the BRP must comply with the Balancing and Settlement Code (BSC), and must supply Elexon with their overall contracted position for each settlement period, known as their Energy Contract Volume Notification (ECVN), prior to gate closure [238]. The BRP is then responsible for paying for any imbalance between their ECVN and their metered position.

the DSO has priority in the red state. Some limitations of [89] to be covered within this thesis are the inclusion of distribution network constraints and including the TSO as a market participant.

2.2.2.3 Application of DSO-TSO coordination models in academic literature

Three of the SmartNet models from [82]: the *centralised Common DSO-TSO market; Shared balancing responsibility market* and *Local market,* are developed further in [91] using game-theoretic analysis to compare the efficiency of the coordination schemes. Once again, the centralised approach offers the highest resource allocation efficiency, however the *Shared balancing responsibility* approach had higher efficiency when modelled using a non-cooperative game compared to the *Local market* which was modelled as a multi-leader Stackelberg game.

In [92], a *decentralised Common DSO-TSO market* approach is followed with the communication between T-D carried out using a ‘generalised bid' function (GBF), a similar concept to the residual supply function of [82], which represents the marginal cost of power generation from distribution. A cut-set approach is used as part of a Benders Decomposition formulation to calculate the GBF, in this case the TSO optimisation is the master problem, and the distribution optimisation is the subproblem. The method is reported to give fast convergence; however, 3 cuts are used to represent the GBF in the case studies considered, and the DSO cost function must be convex for the Benders decomposition to be applied. As the number of DERs increases, more than 3 cuts would be required to accurately represent the distribution cost function which would increase computational time. There is scope for further work in considering the number of cuts required for a close approximation of a more complex cost function, such as in a distribution network with more DERs, and the associated computational times.

In a comprehensive study of the co-optimisation of T-D markets [93], locational marginal prices are calculated, both at T-D, using both centralised and distributed optimisation techniques. The paper does not provide comparison between DSO-TSO coordination schemes, but instead provides methods to allow the centralised and decentralised approaches to be realised. For example, tractable convex relaxation and dual decomposition techniques are developed which can be applied to distributed optimization of networks with millions of nodes.

In [73], an approach similar to the *decentralised Common DSO-TSO market is* applied, with joint procurement of reserve from DERs by both the DSO and TSO. The joint procurement approach is shown to reduce the total system costs compared with sequential procurement of flexibility (DSO then TSO) in the case study presented. The authors of [73] argue that in sequential DSO and TSO markets, undesired price coupling can occur in that the TSO market prices are likely to be higher due to including generation bids. As a result, DERs could increase bids to those the TSO can offer, thus increasing the prices the DSO must pay if they are to procure flexibility from these DERs. While [73] provides valuable insights into joint market clearing, the test network in the case study is not representative of a real system and AC power flow is not implemented, therefore activation of flexibility is arbitrary and events where the DSO and TSO compete for flexibility are not captured.

A useful consideration of cross impacts for the DSO, TSO and retailer is presented in [42] including TSO services (such as demand turn-down) causing congestion at distribution level, or DSO congestion services acting in the opposite direction to TSO reserve services, resulting in further reserve activation required by the TSO. The paper also includes the implementation of uncoordinated (sequential) and co-ordinated (centralised) DSO-TSO models which include the retailer as well as the DSO and TSO. It is shown that the centralised co-ordination improves the welfare of the system compared to the sequential operation. Usefully, the DSO optimises the cost of procuring flexibility against network reinforcement and in the case studied, reinforcement is significantly reduced by implementing a DSO flexibility market. The work in [42] is useful as it considers potential DSO-TSO conflicts and includes the retailer, however, it only considers a centralised DSO-TSO coordination mechanism and could be expanded to consider decentralised coordination mechanisms.

An approach to visualising the effect of DER flexibility on the active and reactive power operating points at the T-D interface is presented in [94]. The results of field trials are presented along with a ‘flexibility maps’ of active and reactive power from DERs. A similar approach is taken in [95] active-reactive power charts are proposed to communicate the flexibility available from the distribution network (i.e. DERs) to the TSO. These methods are useful as a tool for informing the DSO and TSO of the ‘flexibility map’ of active and reactive power, which could be an input to the T-D power flow schedule in the SmartNet *Shared balancing responsibility* model but does not examine how that flexibility would be allocated between the DSO and TSO.

2.2.3 Industrial applications of DSO-TSO coordination

In terms of industrial application, one of the most advanced trials of TSO control of DERs is the Power Potential project [96], where a DER Management System (DERMS) is being employed to coordinate the provision of reactive power services to the TSO from DERs across several grid supply points (GSPs) or T-D interfaces. The control scheme aligns with the SmartNet *Centralised Market* concept where the TSO activates DERs with DSO prequalification to ensure distribution network constraints are respected. While this project is state-of-the-art in the application of DSO-TSO coordination, the DSO does not compete for access to the DERs, and the project is mainly focused on transmission constraints. Although trials are taking place for DSO flexibility markets [71], [79], [80] which do not involve the TSO, the author is unaware of any coordinated DSO-TSO markets, such as those proposed in the literature, in large scale trial or operation. It is anticipated that with increasing uptake of DERs there will be a growing need for coordinated procurement of flexibility between the DSO and TSO, and a gap exists in the development of useful DSO-TSO coordination models which are compatible with existing market arrangements.

2.2.4 DSO-TSO coordination model assessment

The SmartNet models have been assessed for further development based on their compatibility with congested distribution networks with high levels of DERs. 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. Due to the commonalities between the FEUR and SmartNet models, the recommendations of the FEUR report are used in the assessing the SmartNet models where appropriate. The remainder of this section contains more detailed assessment of the five SmartNet models.

<u>Centralised market</u>

The *Centralised market* does not propose a full network model and distribution constraints are only managed through prequalification or validation of TSO market results by the DSO. It is not made clear in [61] [38], [63] how the DERs should be compensated if distribution constraints result in adjustments to their schedules during DSO prequalification or market validation. This model, as presented, appears more suited to uncongested[19] distribution networks with lower penetrations of DERs where in most cases the TSO market dispatch would pass the DSO prequalification/validation. However, in congested distribution networks with high DER penetration, it would be beneficial for the DSO to participate in a market for flexibility, rather than rejecting TSO market outcomes in the event of distribution network constraints.

Centralised Common DSO-TSO

In terms of finding an optimum solution for DER dispatch, the *centralised Common DSO-TSO market* model, which is equivalent to the **Total TSO** model, could (in theory) be the best way of finding the lowest cost dispatch as this formulation would include the entire transmission and distribution network as a single optimisation. Setting aside the computational complexity and timing aspects of adopting such an approach, it is simply concluded in [74] that the **Total TSO** model is not the optimal solution for assigning responsibility between the TSO and DSO. A large T-D system model would make it more vulnerable to small disturbances, and the authors propose that a hierarchical optimisation such as the **Market DSO** model, is preferable. Two of the SmartNet models rely on a single T-D system optimisation and therefore have the same potential issues as the **Total TSO** model. These are the *centralised Common DSO-TSO market* and *Integrated Flexibility market*. The *centralised Common DSO-TSO market* model has been selected to serve as a baseline model (equating to the **Total TSO** approach). However, this is purely for comparison with a theoretical optimum and it is not anticipated that this approach will be suitable in practice due to the reasons outlined above.

Shared balancing responsibility

In the *Shared balancing responsibility* model, the T-D power flow schedule would have to be determined in a dynamic way that balances the needs of both the DSO and TSO. Limiting the TSOs access to DERs could be suboptimal especially if the DSO has little need for DER flexibility in a relatively uncongested distribution network [97]. Due to the challenges of defining an optimum T-D schedule and the potential for suboptimal access to DER flexibility, this model is not developed further.

[19] Operating safely within thermal or voltage or limits, with no risk of exceeding these limits at peak demand or maximum generation output.

Integrated Flexibility

The *Integrated Flexibility market* model presents serious challenges in operation, particularly integrating transmission and distribution constraints into a single neutral market clearing. If there is no priority to the DSO or TSO in accessing DER flexibility, other than the price they are willing to pay, there a high potential for congestion to result in rising system operating costs [98]. Furthermore, the TSO and DSO would need to share their network models and real-time operational data with the neutral market operator. For these reasons, and due to the requirement for a single T-D optimisation, the *Integrated Flexibility market* has not been selected for development.

Decentralised Common DSO-TSO market and *Local market*

The *decentralised Common DSO-TSO market* and *Local market models* have been chosen for further development in this thesis. These models offer advantages over prequalification in the *Centralised market* and do not require a single T-D optimisation as in the *centralised Common DSO-TSO* and *Integrated Flexibility market*. A key difference between the *Local market* and *decentralised Common DSO-TSO market* is that in the *Local market,* the DSO has priority in accessing DERs, while in the *decentralised Common DSO-TSO market,* access is the result of a combined optimisation (see Figure 2-8). The combined optimisation will require two-way communication between the DSO and TSO markets to ensure that both markets reach the same solution.

A summary of the SmartNet model assessment is shown in Table 2-1 which includes the decision on the suitability of the model for further development in this thesis.

Table 2-1: SmartNet model assessment summary

SmartNet Model	Pros	Cons	DSO-TSO priority	Decision
Centralised market	Simplest approach with least coordination	Iterative DSO validation of TSO market clearing	DSO has no access to DER flexibility	Not selected
Centralised Common DSO/TSO	Theoretically optimum solution	Needs full (T-D) network model	Combined DSO-TSO optimisation	Baseline Model.
Shared balancing responsibility	Clearly defined boundaries. DSO and TSO optimise separately	T-D boundary flow schedule could lead to sub-optimal solutions	TSO has no access to DER flexibility	Not selected

Integrated Flexibility	Includes commercial participants.	Needs full (T-D) network model.	Price driven.	Not selected
Local market	Distribution constraints are managed	Complexity in DSO aggregating flexibility	DSO has priority over TSO in DER access	Selected for development
Decentralised Common DSO/TSO	Distribution constraints are managed	Complex two-way market clearing process	Combined DSO-TSO optimisation	Selected for development

2.3 Distribution network congestion management

When distribution networks operate close to their thermal and voltage limits, often due to increased peak demand and high levels of DERs, this is referred to as network 'congestion' [99]. The use of flexibility for congestion management is increasingly being considered as an alternative to network reinforcement[20]. Probabilistic methods can reduce the risk of the DSO over or under procuring flexibility to manage congestion, due to the uncertainty around demand and output from intermittent renewable generation [100].

Congestion management techniques can be categorised into centralised and decentralised approaches [101], [102]. In centralised congestion management, network parameters such as voltage and current are kept within operating limits by a central system operator (SO). The SO will have visibility of the network (at least partially at key monitoring points) and will redispatch generators, possibly via market clearing, to maintain system limits. In GB, transmission network congestion is centrally managed in the balancing mechanism[21] and in most North American markets, wholesale market

[20] In GB, distribution network investment and charges are regulated by Ofgem using price controls, known as 'RIIO' which stands for 'Revenue = Incentives + Innovation + Outputs.' In the next price control framework (RIIO-ED2), which takes effect in 2023 [70], it is stated 'we expect DNOs to first consider whether flexibility, including energy efficiency measures and Demand Side Response (DSR), would provide a more economic and efficient solution than network reinforcement'.

[21] For more detail, refer to Appendix A.

clearing is centralised[22]. However, with increasing penetrations of DERs, which may operate in local or 'decentralised submarkets' [30], there is increasing research interest in decentralised approaches to manage local congestion. In decentralised approaches, multiple entities (such as aggregators) optimise distributed assets, sometimes acting independently to solve local congestion [103], but often acting in coordination with a central SO [102].

The literature on congestion management within distribution networks is numerous and overlaps with the highly researched areas of smart grids, demand response, optimisation of DERs and local markets. In this section, the literature on distribution network congestion management including centralised, decentralised and probabilistic techniques is presented. A critical analysis is then carried out on the compatibility of existing congestion management techniques with the proposed DSO-TSO coordination models.

2.3.1 Centralised congestion management

Centralised voltage control optimization is used in [104] to minimise curtailment of non-firm generators connected at distribution level. A centralised distribution management system (DMS) is proposed in [105] where the DSO can directly control DERs to solve congestion. The DMS is applied to networks with high wind penetration with the objective of reducing curtailment. Although the above approaches are useful in reducing curtailment, they do not provide a competitive market mechanism. A lack of market mechanisms to compensate DERs may discourage investors in generation due to uncertain returns on their investments [34], [106]. Therefore, in this thesis market based congestion management and DSO-TSO coordination schemes are to be developed.

A centralised pricing mechanism is used in the Ecogrid EU flexibility market project [107], where the modelling detail of network congestion is limited to specified feeder limits. The trade-off between using DERs for congestion management and system balancing is presented, which is similar to the competition between the DSO and BRP for DER flexibility in [89]. In the Ecogrid EU approach to congestion management, the

[22] For example, refer to the Californian ISO (CAISO) market: http://www.caiso.com.

DSO defines critical points (often referred to as 'pinch points'[23]) in the network, then requests reduced import/export from aggregators at times when congestion is likely to occur at these points [108]. The major advantage of the Ecogrid EU approach is that it is simple and compatible with existing market arrangements, representing an additional service that aggregators can offer while participating in wholesale and TSO markets [109]. This method could be applied to congestion management, particularly at LV, however, further work is required in identifying the critical points as these are effectively treated as 'static' (always the same) in [108] which may not cover the range of possible causes of network congestion.

2.3.2 Decentralised congestion management

In [110] a decentralised approach is used to calculate prices for a multi-supplier multi-buyer system. Dual decomposition is used to split the overall problem into sub problems for each supplier, and by iteration, the sub-problems converge on the global solution, similar to [111]. This allows suppliers to participate with limited information sharing, however, this comes at the expensive of extra computation resulting from the various iterations of subproblem calculations.

In [112] market splitting between local and national electricity markets is implemented to maximise the value of the decentralised local markets. Critical areas or zones of distribution network are identified where constraints occur and a zonal local market model is implemented. Constraints are treated rather hypothetically in [112] and no mention is made of how the zones in the paper would be identified on a real network.

The proposed flexibility clearing house (FLECH) in [113] offers a market for distribution network congestion management that can be operated in parallel with existing electricity market arrangements (see Figure 2-11). In [113], the FLECH market is run as either a 'single-side aggregator' (SSA) auction where the DSO specifies the required volume of flexibility and accepts offers from aggregators in merit order (cheapest to most expensive) until that volume is provided, or alternatively, a 'supermarket' is suggested where the aggregator proposes flexibility and prices and the DSO optimises their portfolio investment risk (for more details see [113]).

[23] Measurement points in the electricity network which may be operating close to voltage or thermal limits. For example, see https://www.ssen.co.uk/OrkneySmartGrid/.

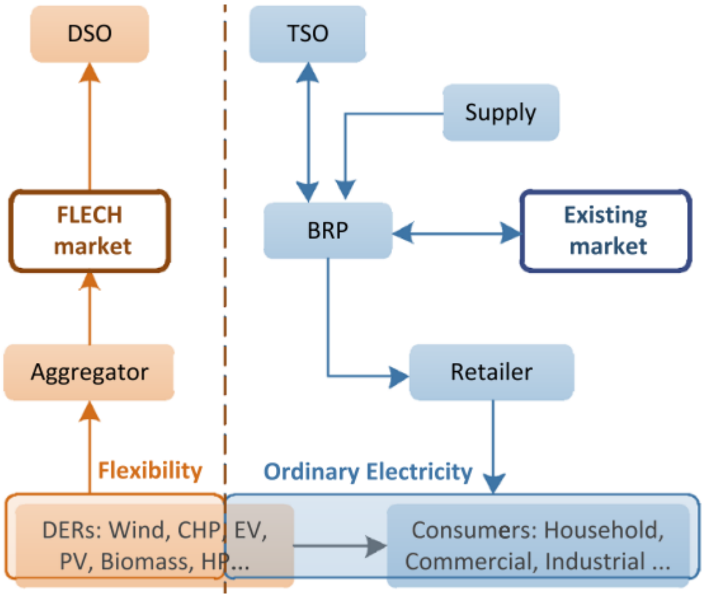

Figure 2-11: FLECH market and existing market parallel operation; source: [113].

In the FLECH market, congestion management is defined as a thermal overload, or voltage and reactive power management. The market structure in [113] is useful in that it runs in parallel with existing wholesale market arrangements and proposes the trading process for flexibility procurement between the DSO and aggregator with rough timescales. However, the method for quantifying required DSO flexibility is not detailed and no detailed case study is provided.

2.3.3 Congestion management modelling methods

Useful methods have been developed in the academic literature to model distribution network congestion management with potential applications in system operation and planning. These methods include distribution locational marginal prices, multi-agent systems and probabilistic modelling.

2.3.3.1 Distribution locational marginal prices

Locational marginal prices (LMPs) are the marginal cost of generating electricity specific to a location on an electrical network [114]. They are applied widely in North America and are calculated as a result of centralised electricity market clearing by the SO which includes network parameters and costs for each generation unit [115]. In European electricity markets, LMPs are not applied, and electricity is traded in power exchanges, with limited involvement by the SO, and limited account for location or network constraints. A major advantage of LMPs is that they give the market direct information on the locational value of generation, giving a clear signal for investment where it is required. Distribution LMPs (DLMPs) are an extension of LMPs to distribution level, and are being researched as a possible solution in the transition to the decentralisation of electricity supply including the application to emerging markets for distribution system congestion management [97].

In [116], a centralised optimisation with DLMPs for unbalanced three-phase networks is proposed for congestion management at distribution, including the use of 'soft normally open points' combined with market mechanisms. In [111], centralised and decentralised approaches are presented to calculate distribution system `shadow prices' which are equivalent to DLMPs. For the shadow price algorithm and BRP optimisations presented in [111], the decentralised shadow price will converge on the centralised calculation, without sharing of information between BRPs, however, this requires several iterations of the BRPs providing positions to the DSO and the DSO recalculating and sharing shadow prices with the BRPs.

In [117], a bi-level optimisation is proposed for day-ahead markets for congestion management. The upper-level optimisation is an optimal power flow (OPF) of the distribution system by the DSO to produce nodal prices (DLMPs). The lower level optimisation is the aggregator flexible load scheduling depending on the nodal prices published by the DSO. In [118] DLMPs are proposed for distribution congestion pricing (DCP) along with a DSO day ahead market integrated into the NordPool[24] spot market. Energy bids are submitted to the DSO by the aggregator, the DSO then calculates the DLMPs using the initial energy bids. In the case of congestion, the DCP is separated from the DLMP, and the aggregator can reschedule energy bids according to these DCPs.

Optimising EV charging to solve congestion at LV has been proposed in [119] with a centralised DSO optimisation with DLMP calculation and decentralised EV fleet optimisation by the aggregator according to the DLMPs. In [119] it was found that the optimal solution of the EV aggregators' problem matches the optimal (most efficient) allocation of EV charging by the DSO. In [99] a decentralised aggregator optimisation is demonstrated for congestion management of distribution networks using DLMPs. The authors use a convex quadratic programming formulation of the centralised DSO

[24]https://www.nordpoolgroup.com/

and decentralised aggregator problems and show that the two optimisations are equivalent.

DLMPs are a popular congestion management technique in academic works, and there is some prospect of them being operationalised in North America where LMPs are applied at higher voltages in centralised market clearing[25]. However, they are not strongly compatible with European electricity markets where wholesale market clearing is carried out with limited consideration of network constraints, and where centralised system balancing markets (often referred to as 'reserve markets') run close to delivery to resolve network constraints. The closest approximation of LMPs in European wholesale markets is the cleared electricity price for each participating country in the coupling of European power exchanges where cross-border transmission capacity is integrated into market clearing[26]. Given that LMPs are not applied at transmission level in GB, it is unlikely that DLMPs will be applied at distribution level without substantial amendment to market operation, balancing and settlement arrangements[27]. In this thesis, congestion management solutions are sought which are compatible with existing market arrangements, therefore, DLMPs will not be considered further.

2.3.3.2 Multi-agent systems

With the widespread deployment of DERs and advances in ICT, the energy system is becoming highly distributed with the potential for multiple control algorithms, or 'agents' operating at different levels which can be modelled or even controlled as multi-agent systems (MASs). An agent is a computer system that operates autonomously within a system to meet design objectives, and a MAS is an integrated system of these agents which communicate to achieve a desired outcome[120]. In the literature on 'smart grids', agents have been applied to simulating the balancing of generation and demand, negotiating energy price, scheduling energy storage and in home energy management including heating and ventilation systems [120], [121].

[25] For example, LMPs are published for the Pennsylvania - New Jersey-Maryland (PJM) regional transmission operator market at https://www.pjm.com/.

[26] The EPEX spot power exchange operates in central western Europe, GB and Scandinavia. Prices are published at https://www.epexspot.com/en/market-data.

[27] An overview of the existing GB balancing mechanism is provided in Appendix A. More details on the balancing and settlement code can be found at https://www.elexon.co.uk/.

In [122] a MAS for modelling DER behaviour in a congestion management scheme is described, which includes device agents, household agents and aggregator agents. A single aggregator is assumed to communicate to the DSO the available flexible demand in its cluster (assumed to be a LV feeder), along with an equilibrium price calculated by the aggregator for matching local supply and demand. The paper refers to [123] for more detail on the platform where 'graceful degradation' is described as disconnecting customers with 'non-firm' connection contracts when market strategies do not relieve congestion at distribution. The platform is again demonstrated in [124] where a Home Energy Management System (HEMS) is proposed to provide network support.

A MAS is again used in [125] where a decentralised approach is favoured over centralised optimisation. The decentralised approach relies on a bid curve transformation aggregated from individual device agents across a feeder. There is limited network information in the formulation which simply assumes a limit to the total flow from feeder and does not model network constraints in any detail.

In one of the few examples of practical applications of MASs in power systems, they have been implemented in the PowerMatching City smart grid demonstrator which involved 25 households in the Netherlands [126]. In the trial, agents are used to trade power for aggregated household devices (e.g., solar PV, EVs, smart appliances) in a real time market to maximise profit for each agent. The DSO is represented by an agent with the objective of optimising network load within the cluster of houses to manage network congestion.

MASs provide valuable insights into the dynamic interaction of the various entities in the smart grid, and agents are likely to play a significant part in future distribution system operation particularly in managing home energy devices. However, in this thesis the operationalisation of congestion management and DSO-TSO coordination schemes will not require the added complexity of modelling agent behaviour at this level of detail.

2.3.3.3 Probabilistic methods for congestion management

With the widespread adoption of domestic solar PV and changing demand patterns caused by HPs and EVs, there is more uncertainty in future domestic demand profiles compared to conventional demands [127]. Combined with the growing deployment of larger intermittent DGs such wind and solar PV farms, this has introduced significant challenges and uncertainty in the planning and operation of distribution networks [128].

With greater uncertainty, there is more risk of over or under investing in network capacity, with the consequence of stranded or inefficient use of network assets [129]. The conventional approach to network planning using static network limits, based on maximum generation/minimum demand scenarios, needs to change to a more probabilistic planning methodology that accounts for generation and load diversity [67]. While flexibility from demand side response (DSR) can provide an alternative to network upgrades, it has been concluded in [129] that probabilistic methods, taking account of planning uncertainty, are required to properly assess the value of DSR.

Probabilistic approaches to assessing network congestion are presented on three-phase LV network models for the north of England in [130] and [131]. The impacts of low carbon technologies are assessed using Monte-Carlo methods to carry out power flow studies from 0 to 100% penetration of EV, PV and HPs. While probabilities of voltage and current violations are presented, the flexibility required to address these violations is not considered.

In [100], a flexibility market is presented, which includes day-ahead and real-time procurement of flexibility using scenario based probabilistic methods to estimate the likelihood of congestion. The DSO is assumed to carry out demand shifting of flexible assets. However, in practice it is more likely that the aggregator would optimise the shifting of demand. Furthermore, arbitrary levels of demand flexibility are assumed (e.g., 10%), and the modelling does not include individual agent behaviour or three-phase LV networks.

Other than using Monte-Carlo or scenario based approaches, methods of estimating LV network congestion and subsequent dispatch of flexibility are rare in the literature. State-of-the-art load forecasting methods are widely applied to aggregated national demand, such as in [132] and [133], however methods of forecasting individual customer demand such as employed in [134] and [135] will be required to more accurately forecast congestion on LV feeders.

2.4 Congestion management requirements by voltage level

In the future, with the decarbonisation of electricity supply and demand, congestion management will be important at all voltage levels, including potential congestion at LV resulting from EVs and HPs [27], [52], which, when aggregated can cause congestion at MV[28]. Distributed generation (e.g. 33 kV connected wind/solar) can cause congestion at HV level [136] and large scale renewable generation such as large onshore wind farms already causes constraints at EHV in GB [14].

In previous works, it has been concluded that due to the potential unbalance between loads on LV networks, three-phase unbalanced approaches should be applied to LV network modelling [137], whereas at MV, balanced phases is an acceptable approximation [138]. At HV, balanced phases are commonly assumed and at EHV the DCOPF approximation of AC optimal power flow can be used with reasonable accuracy on transmission networks with lower *r/x* (resistance/reactance) ratio's [139].

Modelling requirements vary from EHV down to LV: generally increasing in complexity and modelling accuracy with decreasing voltage. This poses a significant challenge as not only is the required modelling complexity increased with lower voltage, the number of nodes also increases dramatically. Taking a high-level example, the number of HV/EHV substations in the English transmission system (owned by NGET) is approximately 395 [140], whereas the number of households connected at LV served by this HV/EHV transmission network is approximately 22.69 million [141].

In the literature, most congestion management methods involving OPF or DLMPs focus on balanced modelling of MV/HV networks and although examples of three-phase (unbalanced) OPF applied to LV networks exist in the literature [142], [143], they are limited by their tractability in terms of the required computational power and time required to solve non-linear AC OPF formulations on large networks. Cloud computing and advances in OPF approaches, such as linearisation and convex relaxations, could improve the tractability of three-phase OPF [144]. However, its application relies on a centralised market where the network constraints are known to the market operator. In practice, for LV congestion management. it may be beneficial to separate the network modelling and market optimisation activities. The optimisation of flexibility could be carried out by a separate entity, such as an aggregator. As highlighted in the Electric Nation trial [145], it is important to provide at least a proxy of network constraints to the aggregator to prevent subsequent actions from causing network stress events.

[28] The definitions of low, medium, high, and extra-high voltage can vary in GB between DNOs and the TSO. In this thesis, low voltage (LV) is defined as 400 V, medium voltage (MV) is defined as 11 kV, high voltage (HV) is 33 kV / 132 kV and extra-high voltage (EHV) is 275 kV / 400 kV.

There are gaps in the literature in DSO congestion management methods: few works provide methods that are compatible with existing market arrangements, such as that proposed in the Ecogrid EU [109] and FLECH [113] projects, but also include detailed network modelling to consider network congestion at all voltage levels including unbalanced LV networks.

2.5 Compatible congestion management approaches

DSO congestion management is an integral part of the DSO-TSO coordination schemes developed in this thesis. The congestion management methodology must be compatible with the TSO system balancing function and existing wholesale electricity market clearing. Within most European countries, wholesale electricity markets are largely decoupled from the electricity networks and are cleared purely on the basis of supply and demand, irrespective of location or constraints on the electricity network[29]. The TSO in these countries must carry out a balancing role, dispatching generation (or flexible demand to a limited extent) in real-time to resolve imbalances and transmission network constraints for secure network operation.

In this thesis, DLMPs or dynamic tariffs[30] which require network constraints to be included in wholesale market clearing will not be considered. Based on the different modelling requirements at different voltage levels, as discussed above, and the need for compatibility with the proposed DSO-TSO coordination model, it is proposed to implement separate distribution congestion management methods for LV and MV/HV. Detailed three-phase network modelling is to be applied at LV where EVs will be both a significant cause of network constraints and source of flexibility in the future.

A tractable LV three-phase congestion management market will be developed that operates in advance of the DSO-TSO coordination market. The constraints from the LV congestion management method must also be fed into the DSO-TSO coordination model which will manage MV/HV distribution network congestion.

[29] The European single market does include cross-border transfer capacity between participant countries, however, internal transmission network constraints within these countries are not generally included in wholesale market clearing. A good overview of the European single market can be found in [239].

[30] For more information on electricity tariff design refer to [240].

2.6 Aggregation of DERs

When considering coordination of access to DERs between the DSO and TSO, it is important to consider the entity contracting directly with the DERs and acting as an intermediary: the aggregator. In recent years aggregators have become established as a provider of aggregated flexibility from multiple smaller DERs to the TSO, for example providing frequency response from batteries and commercial heating and ventilation systems [146] [147]. This section includes high-level frameworks and discussions that describe their role, followed by a review of related academic papers. An analysis of the relevance of this work to the DSO-TSO coordination work in the thesis is then provided.

2.6.1 High-level aggregator frameworks

The Universal Smart Energy Framework (USEF) [65] is a proposed Europe-wide framework for flexibility markets, with the aggregator as the key market player as illustrated in Figure 2-12.

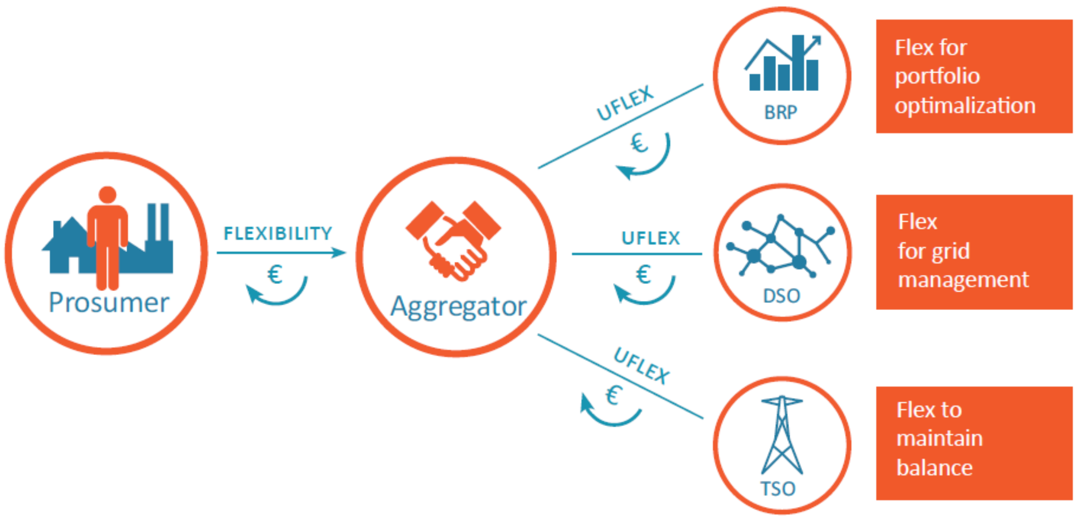

Figure 2-12: Customers for the aggregator's flexibility services; source [65].

The USEF framework provides 7 different models for aggregators [148]. The differences between the models are in the aggregator having its own BRP, or the aggregator having a contract with the BRP, and the method to assign energy volumes between the BRPs. The USEF market design includes distribution network operating regimes similar to the traffic light concept (see section 2.2.2.2) but with green, yellow, and orange stages to indicate the network state (level of congestion). The USEF framework defines a congestion point, a part of the grid where capacity might be exceeded but leaves how to determine these congestion points up to the DSO.

In [64], the subtle distinction is made between an Independent aggregator, without access to the customer meter, and a supplier-aggregator, with a supply licence and access to the meter. By providing DSR, the independent aggregator can cause imbalance to the supplier due to adjusting the demand from the supplier's forecast position. This is referred to as the 'open energy position' and [64] raises the issue of the independent aggregator providing compensation to the BRP for causing this imbalance. Furthermore, a coordinated approach from European regulators on the role of the aggregator is called for in [64], as well as improving access to independent aggregators in both flexibility and energy markets.

Aggregator dispatch schemes can be broadly divided into two categories: fully dispatchable (direct) and price driven (indirect). These are described as follows:

- **Fully dispatchable**: where DERs are under the direct control of an aggregator or other type of VPP operator. This is the approach used in practice by aggregators providing frequency response at short timescales [146] [147], however this can only be done within parameters agreed with the DER customer who can always override or opt out of providing services to the aggregators if required for the core function of the equipment.
- **Price driven:** where price signals or tariffs are offered to households and DER owners such as in [41], [117], however the decision to respond to the price signals are down to individual preferences.

As previously discussed, tariffs are not to be applied in this thesis, to minimise overlap with existing wholesale and retail markets, the modelling of which are out-with the scope of this thesis. It is assumed that DERs will be fully dispatchable by the aggregator or directly by the DSO (possibly via the aggregator) and that suitable contracts between them will be in place. It is envisaged that the DSO will run a long-term LV congestion management market in advance in which aggregators receive contracts to manage LV congestion using DERs (in particular EVs). Furthermore, the DSO-TSO coordination mechanism will include a flexibility market for MV/HV distribution congestion management which takes bids/offers from the aggregator and dispatches them in merit order, similar to the approach taken by the TSO in balancing markets.

2.6.2 Literature on aggregators

The literature on aggregators, or virtual power plants (VPPs) as they are sometimes referred, is extensive. There are numerous papers considering bidding behaviour of VPPs, particularly focusing on uncertainty in the VPP portfolio market position when including intermittent renewables [149]–[151]. However, such papers focus on optimisation of the VPPs portfolio in wholesale markets, and do not account for distribution system constraints which could affect the availability of DERs in a VPP's portfolio. Furthermore, most works on VPPs focus on larger generators, whereas this thesis extends the VPP literature by considering aggregation of larger numbers of domestic flexibility providers, or agents, such as EVs.

In [152], the VPP provides a congestion management service to the DSO on balanced networks at high voltages. In [89] and [90] a local flexibility market (LFM) is proposed, operated by the 'aggregator', providing the platform for trading and scheduling flexibility. Market participants in the LFM include the DSO, the BRP (that, in turn, has commitments in wholesale markets) and DER owners. This is an alternative model to the established definition of an aggregator as a market participant, in which the aggregator's role is like the neutral market facilitator proposed in the *Integrated Flexibility* SmartNet model (see section 2.2.1.3). The approach is useful in considering the competition for DER flexibility between the DSO and BRP, however provides limited consideration of distribution system constraints or coordination with the TSO. Furthermore, given the already established role and definition of aggregators as market participants in industry and academia, the neutral market facilitator should not be termed aggregator.

In [153], a linearised optimisation strategy is presented to maximise profit for the aggregator in providing flexibility from EVs and PV to the TSO and in selling power on the spot market. Distribution network constraints are included within the optimisation, thus covering the requirement of DSO congestion management within this thesis. In practice, power exchange spot markets are cleared with no considering of distribution network constraints and an aggregator is unlikely to have a detailed network model, along with knowledge of other demands to include in their optimisation. To be compatible with existing practice of deregulated electricity markets in Europe, it is proposed that the DSO contract LV congestion management to an aggregator for a given area of electricity network, and provide the aggregator with a proxy for network constraints rather than the distribution network model being included within the aggregator optimisation.

2.6.3 Aggregators and DSO-TSO coordination

In the literature, the competition between the DSO and BRP for DER flexibility via aggregators is covered, however, rarely is the coordination between the DSO, BRP and TSO balancing markets all considered in the same work, such as in [154]. While the focus in the literature is often on an aggregator providing flexibility to a BRP, there is little academic work considering the current situation in GB where adjustments by an independent aggregator to DER positions can cause imbalance for the BRP, i.e. the 'open-energy' position detailed in [64]. It is worth noting that some aggregators are supplier-aggregators which are themselves BRPs, in which case coordination between aggregator and BRP is not required.

In the GB balancing mechanism (BM), when the TSO dispatches flexibility for constraint management, these adjustments are accounted for in their imbalance calculation. In other words, the BRP will not be considered out of position because of balancing action by the TSO. It is assumed in this thesis that the same will apply to the DSO congestion management flexibility market and any imbalance caused by the DSO or TSO in dispatching DERs does not incur imbalance charges to the BRP.

2.7 Discussion of findings

Five models have arisen from the SmartNet project to develop DSO-TSO coordination schemes for facilitating the provision of ancillary services from DERs. Two of these models have been selected for further development in this thesis: The *Local market* and *decentralised Common DSO-TSO market*. The *Local market* model prioritises the DSO in accessing DERs for congestion management and shows promise for application to system balancing. The *decentralised Common DSO-TSO market* model provides an interesting alternative to the *Local market model*, where access to DER flexibility is co-optimised between the DSO and TSO, after being aggregated by the DSO. In both models the responsibility for distribution network management is assigned to the DSO as recommended in the FEUR report. Furthermore, these models are compatible with existing transmission system balancing markets in GB, with the potential for the *Local* or *decentralised Common DSO-TSO markets* to run in advance of, or in conjunction with the TSO balancing markets. The rationale behind the exclusion of the remaining 3 SmartNet models (*Integrated Flexibility market, Shared BRP* and *Centralised market*) is summarised as follows:

- The SmartNet *Integrated Flexibility market* will not be progressed as it requires a single T-D network optimisation by the TSO. It has been concluded that this is too complex a problem to model and a leading report on DSO-TSO coordination recommends against it [74].
- The SmartNet *Shared BRP* model has been shown in the literature to result in lower social welfare than the other models when applied to system balancing [56].
- The *Centralised market* does not include distribution network constraints except in prequalification, and the DSO does not participate in any market for flexibility to manage distribution system congestion. This model reflects current practice; however, it does not sufficiently solve the problem of DSO congestion management in a future with high penetration of DERs.

The SmartNet *centralised Common DSO/TSO market* (which also involves a single T-D network model) is to be used as a theoretically optimal baseline, purely for comparison with the two selected models and not as a practical option.

Further work is needed to define how the DSO can aggregate DERs in a non-discriminatory fashion and how access to DERs should be prioritised to ensure reliable operation of the *integrated grid* as recommended by the FEUR report. There is limited literature which compares the available DSO-TSO models and there is scope for further exploration of the two models selected for study. In the application of the d*ecentralised Common DSO-TSO market*, the aggregation of DERs using a residual supply function warrants further investigation, in particular with respect to the trade-off between accuracy and computational burden associated with calculating the supply function. There are clear gaps in the literature on the design of the *Local market* TSO-DSO coordination model and further work is required on the allocation of flexibility between the DSO and TSO. In [74], the DSO and TSO are reserved half of the available DER flexibility each, however an alternative method could be considered which allocates flexibility in a less arbitrary or static fashion. One such method is the traffic light concept, which will be applied to the allocation of DER flexibility between the DSO and TSO in the *Local market*.

From the analysis of distribution network congestion management, there are research gaps in developing a method that is both compatible with existing electricity market arrangements and provides adequate distribution network constraint modelling. This thesis proposes separate markets for LV and MV/HV congestion management due to the different modelling requirements between LV and MV/HV, namely the requirement for three-phase (unbalanced) network modelling at LV and balanced network modelling being adequate at MV and above. In this thesis, it is proposed to contract three-phase LV network congestion management in advance using a tractable method suitable for tens of thousands of nodes, and to carry out single-phase MV/HV congestion management at gate closure in a DSO-TSO coordination mechanism which is compatible with the existing wholesale and balancing market arrangements in GB.

The aggregator as noted in the literature is a central market player in congestion management and DSO-TSO coordination activities. In this thesis, the aggregator portfolio optimisation is considered in LV congestion management, whereas, in DSO-TSO coordination modelling, DERs (individually or aggregated) are to be optimised with the objective of minimising system balancing costs rather than maximising aggregator profits.

2.8 Chapter summary

In this chapter, the literature on DSO-TSO coordination models has been considered. High-level DSO-TSO coordination models have been assessed in terms of complexity, compatibility with the GB electricity market, and in their application to system balancing and distribution system congestion management. Three of these models have been selected for further development in this thesis: The SmartNet [38] *Local*, *decentralised Common DSO-TSO* and *centralised Common DSO-TSO* markets.

In the next chapter, to address the research gaps identified from the literature review, the *Local market* and *decentralised Common DSO-TSO market* will be developed to include a MV/HV distribution system congestion management market operated by the DSO. Subsequent chapters will also develop approaches for LV distribution congestion management that are compatible with existing electricity market arrangements in GB.

Chapter 3:

DSO-TSO Coordination Modelling

In this thesis, models are developed to coordinate access to DERs between the DSO and TSO. A review of the prominent DSO-TSO coordination models in the literature has been conducted and three of the SmartNet [38] coordination models: *Local, decentralised Common DSO-TSO*, and *centralised Common DSO/TSO* markets have been selected to be developed for application to distribution networks with high levels of DERs.

In this chapter, DSO-TSO coordination models are developed to facilitate access to DERs: for MV/HV congestion management in the case of the DSO, and for system balancing and EHV congestion management in the case of the TSO. The outline of this chapter is as follows: the integration of the coordination schemes within the GB electricity market timeline is presented; the coordination models are then developed; and finally, the optimisation methods used in the coordination models are detailed.

Henceforth, for brevity, the *decentralised Common DSO-TSO market* model is referred to as the *Decentralised* model and the *centralised Common DSO-TSO market* model is referred to as the *Centralised* model.

3.1 Market timeline

Figure 3-1 illustrates how the proposed DSO-TSO coordination schemes integrate within the GB electricity markets timeline (further explanation of which can be found in Appendix A) comprising day-ahead and intraday power exchange auctions, ancillary service markets for reserve and frequency response running a month or more ahead, and the BM running from gate closure. The 'DSO Market' is an additional market mechanism proposed in this thesis for distribution network congestion management as part of the *Local market* and *Decentralised* DSO-TSO coordination mechanisms. The DSO Market coordinates with the TSO BM using the DSO-TSO coordination models developed in the remainder of this chapter.

In this thesis, it is assumed that the market positions of all transmission connected generation and DERs are determined as a result of forward markets (bilateral trades and day-ahead/intraday power exchanges). These positions are provided to the SO (DSO or TSO) at 'gate closure', which in GB is 1 hour prior to delivery for the TSO. This mirrors the operation of most European liberalised electricity markets where the role of the TSO is to resolve network constraints and imbalances as a result of these forward market positions [155]. In the *Local market* and *Decentralised* DSO-TSO coordination schemes developed in this thesis, the DSO gate closure is ahead of that of the TSO's because the DSO carries out congestion management, aggregates DERs and communicates market results to the TSO in advance of the TSO market. The DSO gate closure must allow sufficient time for these activities, and it is proposed in this thesis that the DSO gate closure is 1 hour ahead of the TSO gate closure although this is not prescriptive and could be adjusted[31]. For timeseries analysis carried out in this thesis, the DSO and TSO markets will be modelled at 30 minute timesteps for consistency with a settlement period in the BM which is 30 minutes as shown in Figure 3-1.

[31] For example, the GB BM gate closure was initially set at 3.5 hours before delivery, which was revised to 1 hour to reduce participant exposure to imbalance charges [241].

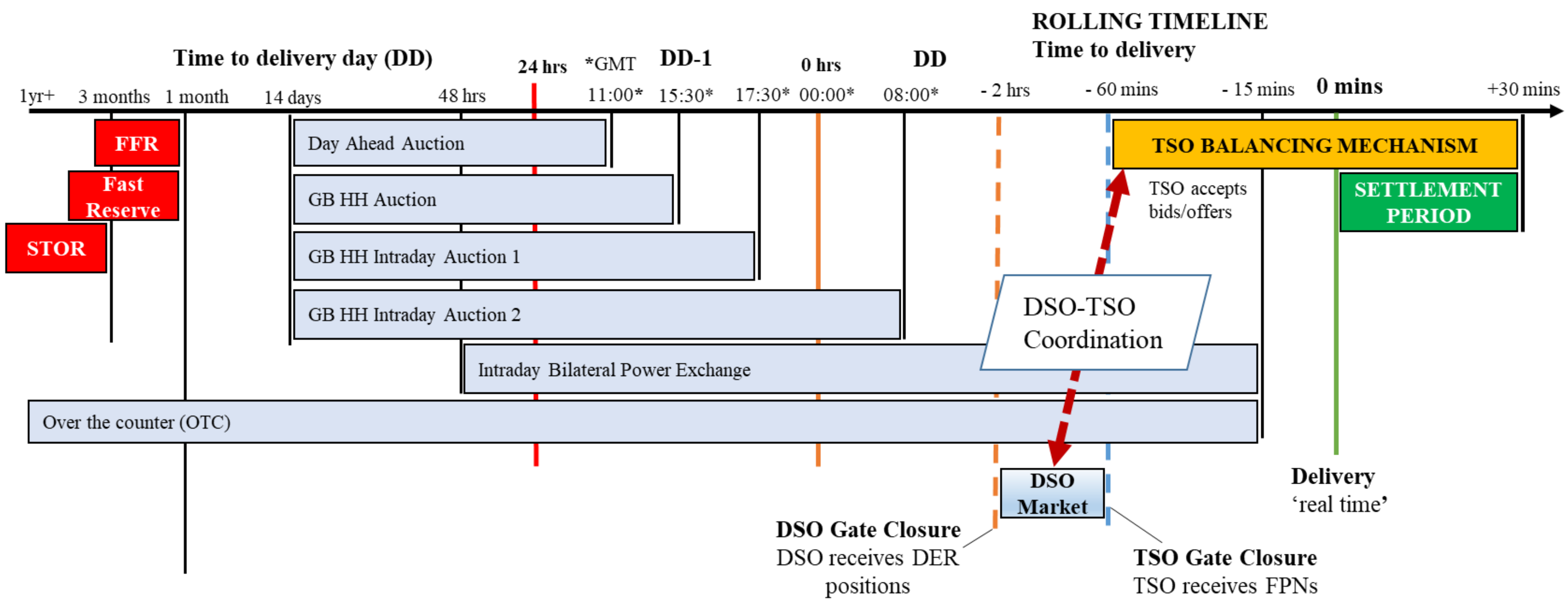

Figure 3-1: Timeline for GB electricity markets[32] *including proposed DSO Market and DSO-TSO Coordination; data:* [7] [156] [157]. *MFR – Mandatory Frequency Response, FFR – Firm Frequency Response, STOR – Short Term Operating Reserve, FPN – Final Physical Notification.*

[32] For more detail on the GB electricity wholesale and balancing mechanism refer to Appendix A.

3.2 DSO-TSO coordination models

The DSO-TSO coordination models developed in this thesis (*Centralised, Decentralised and Local market*) have the dual objectives of MV/HV congestion management for the DSO and system balancing and EHV congestion management for the TSO. In the *Decentralised and Local market* models, the term 'DSO' can indicate multiple DSOs operating markets at multiple T-D interfaces. The TSO coordinates all DSOs and manages the power flow over each T-D interface based on the results of a transmission level balancing market. The coordination models consider markets for active power redispatch, and while reactive power is included in the AC power flow studies, the management or coordination of reactive power is not considered in this thesis which should be considered in future work.

In this section, the *Centralised* model is developed followed by the *Decentralised* and *Local market* methodologies of aggregating and prequalifying DER flexibility for participation in the TSO market.

3.2.1 Centralised model

The *Centralised* model is the most straightforward in terms of coordination between the TSO and DSO. It extends existing TSO balancing system designs, such as the GB BM, by including distribution constraints within a single T-D network model. As shown in Figure 3-2, all transmission and distribution connected market participants submit their contracted positions to the central balancing market operated jointly by the DSO and TSO[33]. By carrying out optimal power flow with balancing (described in section 3.3), the system operator determines any imbalances or network constraints, and redispatches generation and flexible demand to resolve them.

[33] In the *Centralised* model, the term 'TSO' represents the combined DSO-TSO market operator on the T&D network.

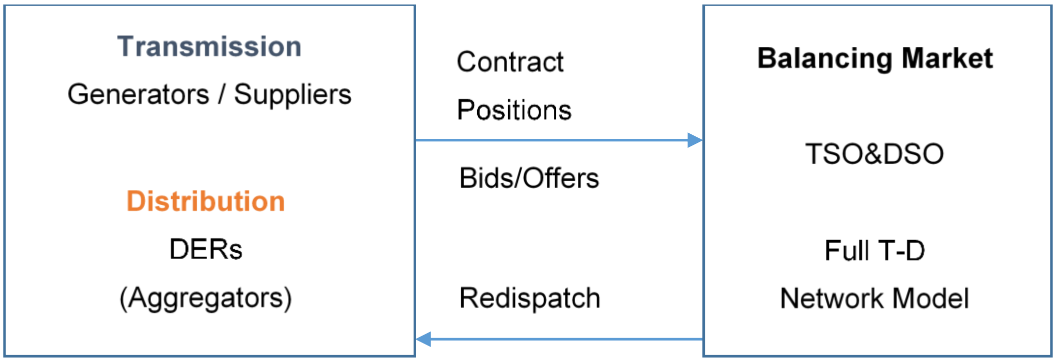

Figure 3-2: Centralised coordination model schematic.

In the GB BM, BRPs (including generators and suppliers) are required to submit positions one hour ahead of delivery (gate closure). Generators and any flexible demand also submit bids and offers[34] for the TSO to adjust their positions (redispatch) in the balancing market. The *Centralised* model extends the existing GB BM market design by including distribution connected balancing parties (DERs, and aggregators) along with distribution constraints within the system balancing model. The dispatch is to be optimised using a nonlinear ACOPF balancing formulation which is detailed in section 3.3. It should be noted that in GB it is mandatory for large transmission connected generators to participate in the balancing market, whereas for suppliers and distribution connected assets this is optional.

3.2.2 Local market

In the *Local market* model shown in Figure 3-3 the DSO manages distribution network congestion by operating a traffic light style congestion market, the concept of which was introduced in section 2.2.2.2. The DSO market clears ahead of the TSO gate closure and provides adjusted DER limits and set points to the TSO at gate closure of the TSO market.

The DSO does not aggregate DERs, but instead adjusts DER positions to manage distribution network constraints (in the 'red' state) and updates DER limits (or bounds) to prevent actions by the TSO causing congestion at distribution level (in the 'amber'

[34] As is convention in the GB BM [238], in this thesis a bid represents the cost to reduce generator output, and an offer represents the cost of increasing output, both are in £/MWh.

state)[35]. With the potential network congestion removed (the 'green' state), any remaining flexibility is available for participation directly in the TSO market. In terms of allocation of costs, the DSO pays for adjustments to DER positions to resolve distribution constraints, and the TSO pays for any further adjustments to DER set points as a result of the TSO balancing market.

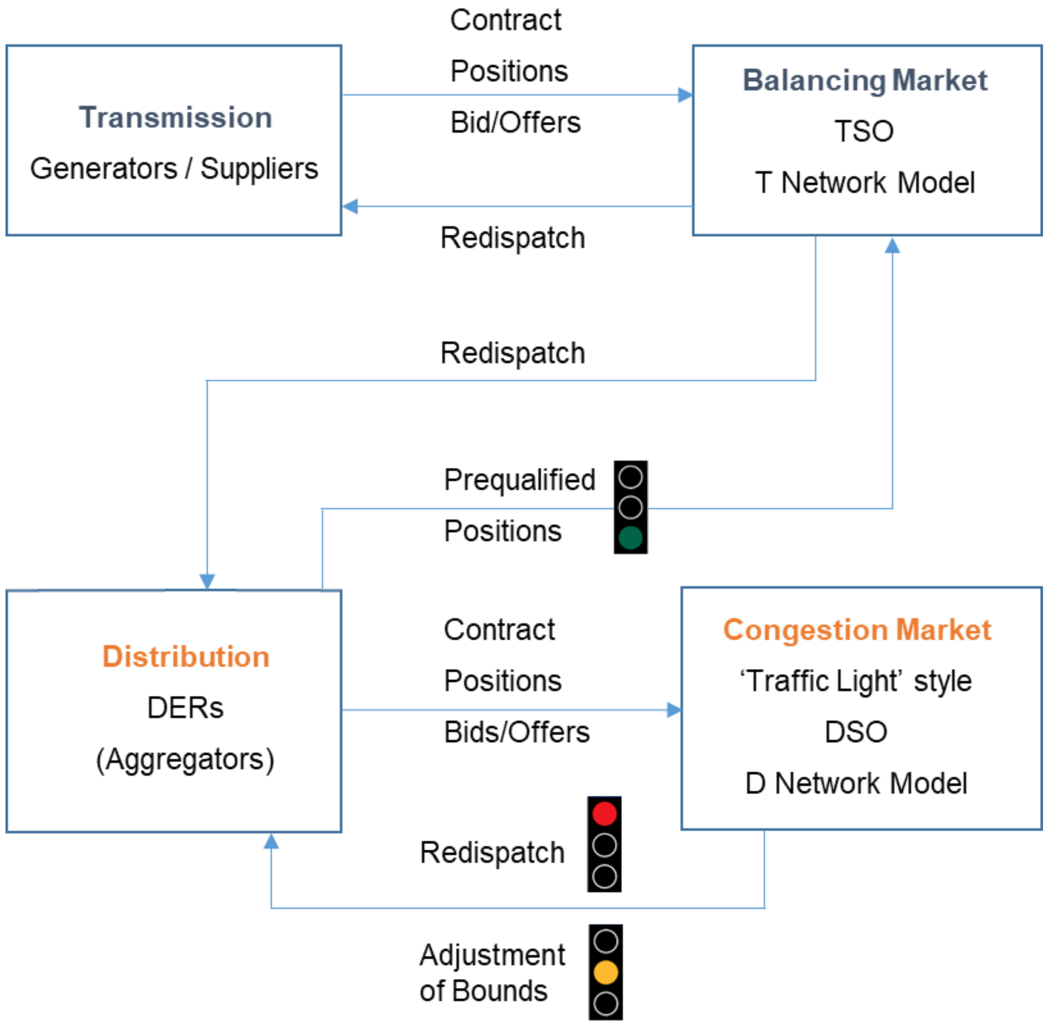

Figure 3-3: Local market model schematic.

3.2.2.1 DSO congestion market

The first stage is for the DSO to check the feasibility of possible market outcomes, by taking the positions (p_g^G) of all DERs and demands, along with the upper (P_g^{UB}) and lower bounds (P_g^{LB}) of the flexible DERs. The DSO uses an ACOPF with balancing

[35] Redispatch is carried out by the TSO in the balancing market using the adjusted and prequalified DER positions provided by the DSO.

optimisation to detect and resolve network congestion, with bids ($C_g^{\downarrow}$) and offers ($C_g^{\uparrow}$) from flexible DERs to move down or up from their respective positions within the limits of the bounds provided.

This network congestion check is carried out twice: for all DERs at their upper bounds and at their lower bounds. The DSO can concurrently check both the upper and lower bounds, UB and LB respectively, by setting p_g^G to P_g^{UB} and P_g^{LB}, respectively, for all DERs, as shown in Figure 3-4. If no network congestion occurs for either the upper of lower bounds, the network is in the 'green' state, however if there is potential congestion, the network enters the 'amber' state.

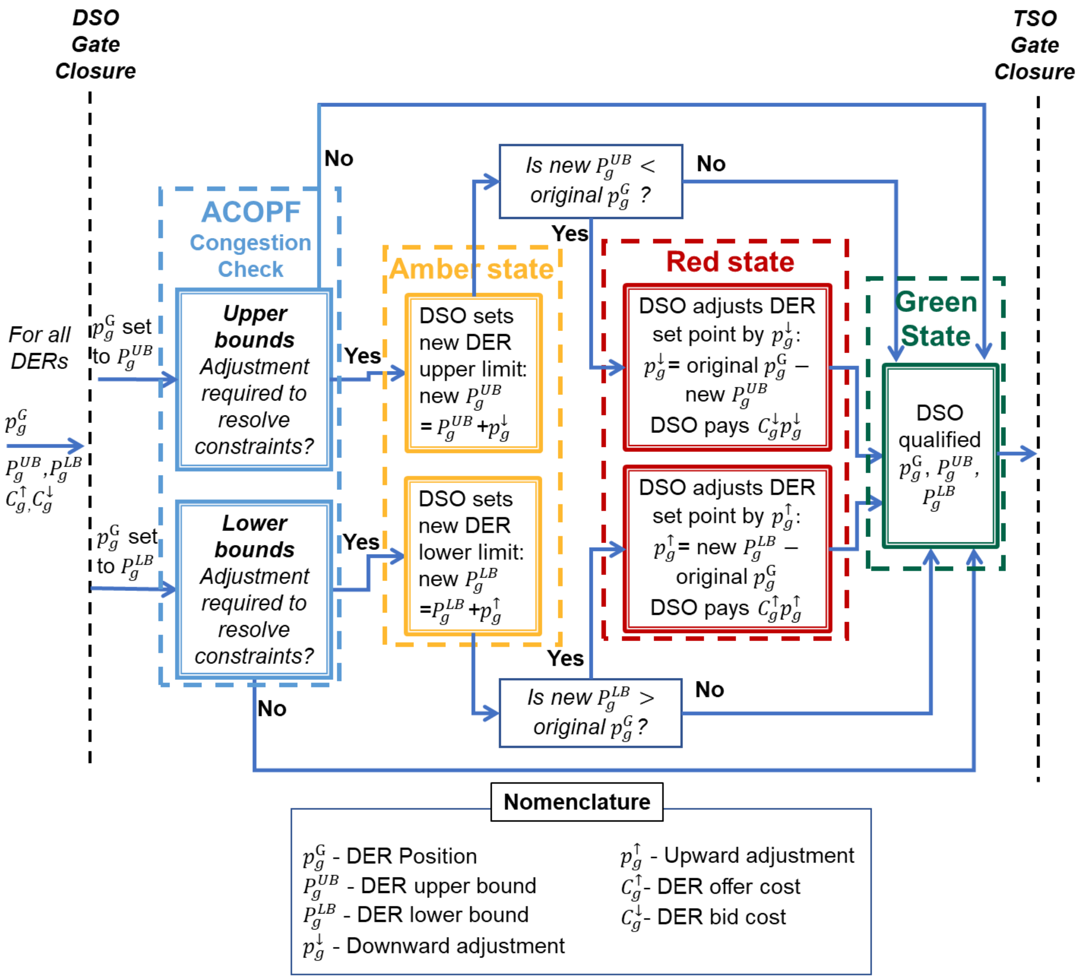

Figure 3-4: DSO congestion market operation: amber, red and green states.

Amber state

In the amber state, DERs have made bids/offers that could potentially cause congestion. In this case, adjustments are made to the original DER bounds (P_g^{LB} and P_g^{UB}) to maintain the network within thermal and voltage limits for all DERs either at their upper or lower bounds. If the original DER set points (p_g^G) do not require any adjustments to maintain the network within thermal and voltage limits, the network is returned to the green state. If adjustments are also required to the original DER set points, the network enters the 'red' state.

Red state

In the red state, the declared positions of DERs (p_g^G) will cause network congestion if not adjusted and it is triggered when adjusted DER bounds in the amber state also require a subsequent adjustment to p_g^G. For example, if a new (adjusted) upper bound P_g^{UB} from the amber state is lower than the original p_g^G, then p_g^G will also need reduced as it cannot exceed the new upper bound. The DSO pays for any adjustment to p_g^G based on the bid/offer costs of the DERs ($C_g^{\downarrow}/C_g^{\uparrow}$)[36]. Once these adjustments to p_g^G have been made to resolve potential congestion, the network returns to the green state.

Green state

When the network is in the green state, the DERs can participate directly in the TSO market, within the DER bounds qualified by the DSO, without the risk of causing constraints at distribution level. If there are no distribution network constraints for the submitted upper and lower bounds of DERs, there will be no need for adjustments by the DSO and the cost will be zero.

3.2.2.2 TSO balancing market

After DSO market clearing, the distribution system demand, $\sum_{d \in D} p_d^D$, is aggregated to the distribution bus at the T-D interface, and DERs are added directly as individual units with values of p_g^G, P_g^{UB} and P_g^{LB} cleared by the DSO.

[36] The DERs could also be paid for adjustments to their bounds in the amber state, and this is explored in the case studies in the following chapter. The default approach is not to pay the DERs for adjustments to their bounds in the amber state but to pay for adjustments to their set points in the red state.

The T-D interface flow, F_s, makes up the difference between total DER positions ($\sum_{g\in G} p_g^G$) and total demand ($\sum_{d\in D} p_d^D$) at distribution after DSO market clearing, including losses, thus;

$$F_s = \sum_{g\in G} p_g^G - \sum_{d\in D} p_d^D + Losses \qquad (3-1)$$

where F_s is bounded by the T-D transformer capacity.

Transmission network modelling

The transmission network modelling approaches covered in this thesis include: a single transmission bus model with connection point to the wider grid; a limited transmission network model with connection point to the wider grid; and a transmission network model with no wider grid connection.

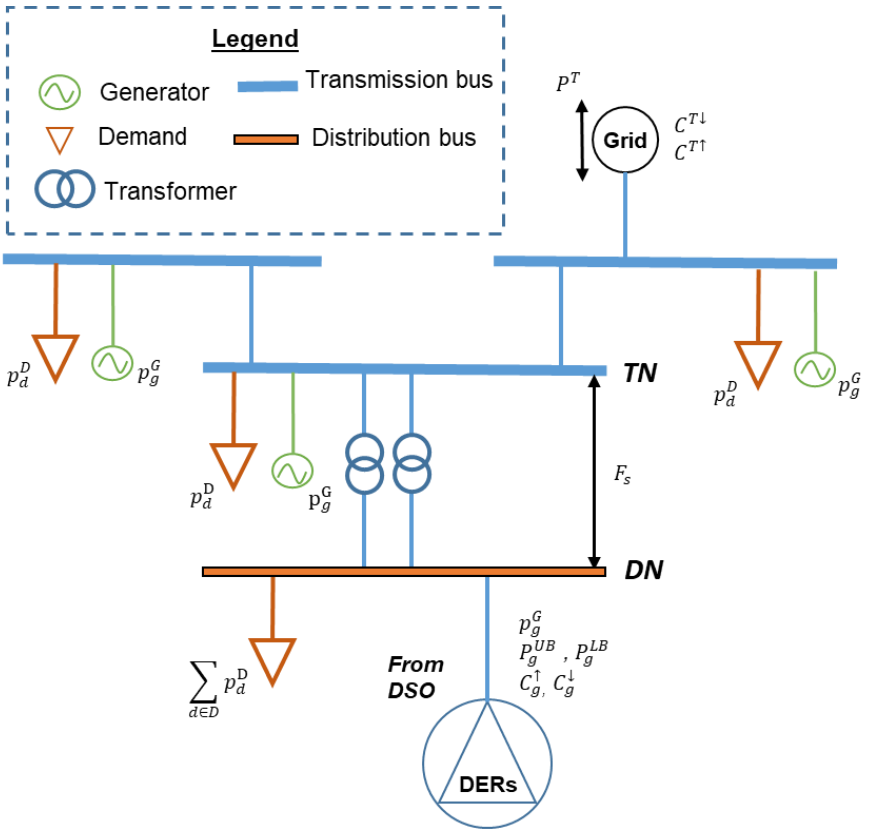

Figure 3-5: Transmission bus with aggregated distribution demand and DERs. N represents a T-D interface between transmission bus TN and distribution bus DN

Figure 3-5 illustrates a limited transmission network model with connection to the wider grid. One T-D interface is shown between buses *TN* at *DN;* however, multiple

T-D interfaces can be included in the transmission market model taking prequalified DER positions from multiple DSO *Local markets* run in parallel. Transmission connected generation can be modelled to participate in the TSO balancing market in the same way as DERs.

Where the connection to the wider transmission grid is modelled, P^T represents the grid import/export power flow with associated costs, $C^{T\uparrow}$ and $C^{T\downarrow}$, for increased or decreased grid import, respectively.

TSO balancing market operation

The TSO market operates using the same balancing model with the same objective function as the DSO market. A DCOPF balancing model, with reduced computational cost, could be sufficient for the TSO, due to lower losses and voltage variation.

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

3.2.3 T-D interface power flow adjustment cost

In both the *Decentralised* and *Local market*, there is no cost to the DSO for adjusting the D→T power flow. In both models, the DSO minimises the amount of adjustments to DERs to manage distribution network congestion and import/export across the T-D interface is at zero cost. An alternative to this approach could be the TSO setting a dynamic cost on D→T power flow depending on transmission capacity and supply/demand balance. However, in this thesis it is asserted that the DSO should not be penalised for transmission level constraints and instead their role should be to minimise redispatch costs to manage distribution constraints. In the models proposed in this thesis, the DSO will not reduce output from renewable generators such as PV and wind, unless distribution constraints arise, even if this coincides with a period of generation surplus for the TSO.

The *Decentralised* and *Local market* coordination models provide a mechanism for the TSO to adjust output from DERs, in competition with transmission level resources, to manage transmission constraints and to balance supply and demand. Therefore, if there is a surplus of renewable generation or transmission constraint, the TSO can access the cheapest sources of flexibility from distribution and transmission level assets to balance supply and demand or manage the constraint, however the DSO will not bear the cost of these actions. There will be instances where actions by the DSO are in conflict with the goals of the TSO and these are explored in the case studies in the following chapter.

3.2.4 Decentralised model

In the *Decentralised* model, the responsibility for managing distribution network congestion falls to the DSO. The DSO runs a congestion market, shown in Figure 3-6, in which participating flexible DERs provide bids and offers to adjust output from their contract positions to resolve constraints.

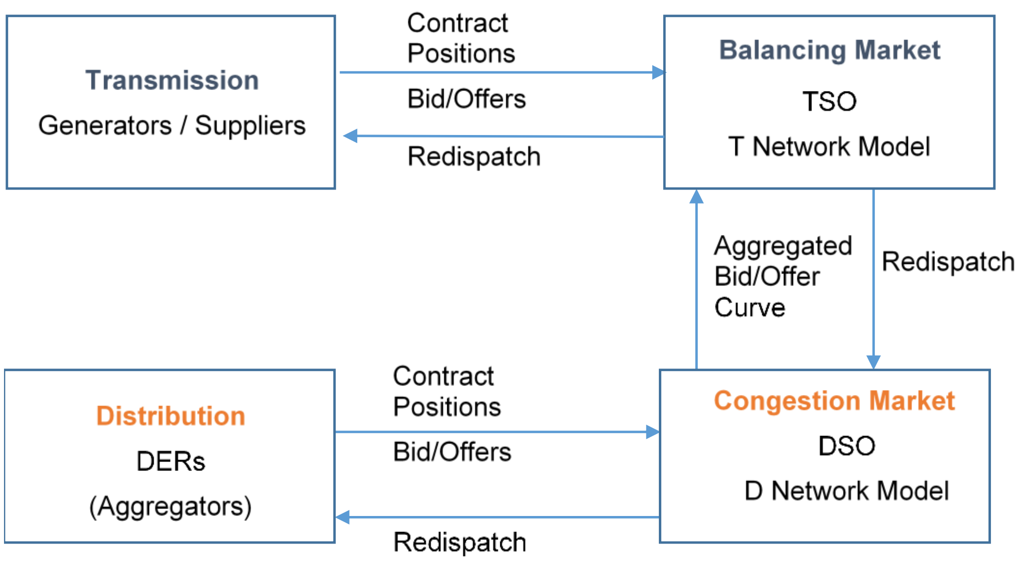

Figure 3-6: Decentralised model schematic

The operation of the *Decentralised* and *Local market* congestion markets are very similar, and the traffic light style approach used in the *Local market* could be applied to the *Decentralised model* with the same implementation of the red and amber states. However, in the green state of the *Local market* DERs participate directly in the TSO market which is not the case for the *Decentralised* market. Instead, in the *Decentralised* market the DSO calculates aggregated bid and offer curves to represent the total flexibility cost for all DERs, while respecting distribution network constraints, and passes these to the TSO.

Following the operation of the DSO congestion market, the TSO operates the transmission system balancing market which includes transmission connected assets and distribution system flexibility represented at the T-D interface (grid supply points) by the aggregated bid/offers from the DSO. After the TSO market clears, the TSO passes redispatch instructions for the aggregated DERs to the DSO. The DSO then activates the aggregated volume requested by the TSO by redispatching the DERs.

This *Decentralised* model introduces a significant increase in complexity in terms of coordination between the DSO and TSO (compared to the *Centralised* model) with multiple DSO markets aggregating DERs potentially at every T-D interface. However, this allows for parallelisation and greater scalability by dividing the single large T-D model with one operator into multiple network models with multiple DSOs.

The details of the DSO congestion market, aggregated bid/offer curve methodology, TSO system balancing and DSO redispatch are outlined in the following.

3.2.4.1 DSO congestion market

In the *Decentralised* model the DSO congestion market operates to resolve any distribution constraints at minimum cost, and to determine the resulting optimal D→T flow for the DSO. The *Local market* traffic light methodology including red and amber states from Figure 3-4 can be applied to the DSO congestion market, with DERs being compensated for adjustments to set points in the red state or having upper and lower bounds adjusted to prevent possible network congestion in the amber state. The DSO congestion market takes place ahead of the TSO market, with the following steps carried out by the DSO:

1. Receive market positions of all DERs (p_g^G) and inflexible demands (P_d^D), along with the upper (P_g^{UB}) and lower bounds (P_g^{LB}), bids ($C_g^{\downarrow}$) and offers ($C_g^{\uparrow}$) from flexible DERs to move down or up from their respective positions.
2. Determine optimal D→T flow, F_S, with no consideration of transmission constraints.
   - F_S is the D→T flow corresponding to the minimum DER adjustments required to solve distribution network congestion.
   - The optimal objective function, O_S, is the minimum cost of any adjustments to DER positions required to solve network congestion calculated using an ACOPF balancing formulation.
   - The D→T active power flow (import/export to transmission) is at zero cost.

3. Determine the feasible upper and lower bounds for D→T active power flow (F^{UB} and F^{LB} respectively) based on the results of ACOPF for all DERs set at upper and lower bounds (P_g^{UB} and P_g^{LB} respectively):
   - Follow the ACOPF congestion check methodology from the *Local market* traffic light scheme (see Figure 3-4), including red and amber states.
   - DERs are paid for adjustments to p_g^{G} in the red state, but are not paid for adjustments to upper and lower bounds (P_g^{LB} and P_g^{UB})[37].

3.2.4.2 Aggregated bid/offer curve methodology

Once any required adjustments are made to DER set points and upper/lower bounds in the DSO congestion market, the DSO provides an aggregated bid/offer curve to the TSO for each T-D interface to represent the costs of adjusting the D→T active power flow. The TSO can then use the DSO aggregated bid/offer curve to optimise power flow at each DSO-TSO interface during transmission system balancing. In this thesis, the DSO aggregated bid/offer curve is represented using a piecewise linear (PWL) function of bid and offer costs for adjustments of the D→T flow (F_n) from its optimal set point (F_S). The steps taken by the DSO to calculate the aggregated bid/offer curve are as follows:

1. An aggregated bid/offer curve is constructed based on a PWL cost function, for a range of D→T flows, $F^{LB} < F_n < F^{UB}$, for z evenly distributed points F_n. Reductions of F_n from F_s are bid points ($F_n^{\downarrow}$):

$$F_n^{\downarrow} = F_S - \frac{(F_S - F^{LB}) \times n}{z}: \ 1 \geq n \geq z \tag{3-2a}$$

   Increases in F_n from F_s are offer points ($F_n^{\uparrow}$):

$$F_n^{\uparrow} = F_S + \frac{(F^{UB} - F_S) \times n}{z},: 1 \geq n \geq z \tag{3-2b}$$

2. For each value of $F_n^{\downarrow}$ and $F_n^{\uparrow}$, the bid and offer costs, $\mathrm{C}_n^{\downarrow}$ and $\mathrm{C}_n^{\uparrow}$ are calculated for adjusting the D→T flow from F_s to F_n as follows:
   - The D→T flow is fixed at F_n

[37] The DERs could also be paid for adjustments to their bounds in the amber state, and this is explored in the *Local market* case studies in the following chapter.

- Using ACOPF balancing formulation, the cost, $C_n^{\uparrow}$ and $C_n^{\downarrow}$, is calculated for the DER adjustments to achieve each value of $F_n^{\uparrow}$ and $F_n^{\downarrow}$ respectively.

3.2.4.3 TSO balancing market

At DSO market gate closure, the DSO passes the aggregated bid/offer curve for every T-D interface to the TSO for use in the transmission system balancing optimisation. Along with the bid/offer curve, comprising bid $C_n^{\downarrow}$ and offer $C_n^{\uparrow}$ costs and the range of bid points $F_n^{\downarrow}$ and offer points $F_n^{\uparrow}$, the DSO also passes the optimal set point F_s and upper and lower bounds of D→T power flows, F^{UB}, F^{LB}.

As well as the aggregated bid/offer curves representing the cost of adjustments to T->D set point, F_s, for the DSO, the TSO receives transmission connected generation set points p_g^G, and their respective bid and offer costs $C_g^{\downarrow}$ and $C_g^{\uparrow}$. At the TSO gate closure (1 hour ahead of delivery), the TSO then carries out transmission system balancing using an ACOPF balancing formulation to resolve constraints and match supply and demand at lowest cost. To do this the TSO can adjust transmission connected generator set points or adjust the D→T flow at each T-D interface.

3.2.4.4 DSO Redispatch

Based on the results of the TSO system balancing optimisation, the TSO passes redispatch instructions to transmission connected generation and revised D→T set points, F_R, to each DSO, as required to solve network constraints and/or balance supply and demand. If transmission constraints do not occur and supply/demand is balanced, or if it is cheaper to adjust transmission assets than to change D→T flows, there will be no redispatch instructions sent to the DSOs which will remain at their optimal D→T active power flow set point, F_s.

When the DSO receives redispatch instructions from the TSO, the D→T flow at each DSO interface is fixed, at the revised set point, F_R. The DSO then repeats its system balancing optimisation to make the adjustments to DER set points, p_g^G, to manage distribution constraints and provide the TSO with the requested D→T flow, F_R.

The *Decentralised* model has an additional stage on the market timeline shown in Figure 3-1 as the DSO carries out redispatch of DERs after the TSO market. To implement the *Decentralised* model, sufficient time from gate closure to delivery will be required for the TSO to pass instructions to the DSO and for the DSO to carry out redispatch of DERs. Currently the TSO has from 1 hour ahead of delivery to carry out redispatch, which would need either include the final DSO redispatch, be shortened to allow time for DSO redispatch, or lengthened to allow time for both TSO and DSO redispatch. Having the DSO carry out redispatch after the TSO balancing market adds an additional challenge to maintaining system frequency as actions by the DSO may be counter to short term frequency response actions by the TSO. This appears to be a disadvantage of the *Decentralised* model which is not explored further in this thesis but could be studied in further work.

3.3 Optimisation methods

To carry out electricity system balancing, tools are required to model both the network and optimal dispatch of resources. Currently, even at transmission level in GB, adjustments by the TSO to manage system constraints are often carried out based on minimising the number of instructions, particularly at short timescales [158]. However, with increased information and communication technology (ICT), including smart meters and increasing numbers of smaller DERs, rather than large, centralised generation, the TSO and DSO will likely require tractable, and largely automated, tools for dispatching flexibility for system balancing. These tools could be utilised by NGESO in the GB balancing mechanism and by DSOs to manage distribution constraints as part of DSO-TSO coordination models such as those proposed in this thesis.

In academic works such as [93], [119], [143], optimal power flow (OPF) is used to find the lowest cost dispatch while satisfying network constraints. In North American markets, security constrained economic dispatch, a simplified approach to OPF, is used in centralised wholesale market clearing [159]. This thesis makes extensive use of OPF in the proposed DSO-TSO balancing market coordination. Using OPF at distribution level poses some unique challenges compared to transmission. Firstly, at transmission level it is usually acceptable to ignore losses and assume voltages are at their nominal value across the network. The most commonly applied technique incorporating these assumptions is DCOPF, which allows the non-linear ACOPF power flow equations to be linearized by assuming all voltage angles are close to zero [160]. This significantly reduces computational time as well as guaranteeing a globally optimal solution. However, at distribution level, the *r/x* ratio is higher, resulting in higher losses and voltage variation. Therefore, the ACOPF must be applied, or at least approximated, to include losses and voltage to have a more accurate representation of network constraints at distribution. Limitations of the non-linear ACOPF formulation used in this thesis are that a globally optimal solution is not guaranteed; it assumes balanced phases which is often not the case at LV; and the method is not tractable to apply to hundreds of thousands or even millions of LV nodes. To address the tractability of using ACOPF at LV, it is proposed to use a heuristic three-phase (unbalanced) load flow method for congestion management at LV (described in chapter 5) and ACOPF at higher voltage distribution (11 kV and above).

In the *Local market* and *Decentralised* DSO-TSO coordination models developed in this thesis, DCOPF is applied to transmission level balancing markets operated by the TSO and ACOPF is applied to distribution level congestion management by the DSO. In the *Centralised* model, ACOPF is applied in single optimisation model at distribution and transmission. Further details on the ACOPF and DCOPF formulations applied in this thesis are provided in the following.

3.3.1 ACOPF formulation

The ACOPF was first formulated in the 1960s [161] and has been developed and widely applied since. The following formulation, from [162], is in polar coordinates. Consider an electricity network, where $\mathcal{G}$ is a set of generators (at transmission level) or DERs (at distribution level)[38], $\mathcal{D}$ is a set of demands; $\mathcal{B}$ is a set of buses; $\mathcal{L}$ is a set of lines; $\mathcal{G}_b$ and $\mathcal{D}_b$ are sets of generators/DERs and demands at bus b; $\mathcal{B}_b$ is a set of buses connected by a line to bus b; b_0 is the slack bus; P_d^D and Q_d^D are the real and reactive power demand of load d; p_g^G and q_g^G are the real and reactive power output from generator/DER g; P_g^{LB} and P_g^{UB} are the lower/upper bounds on p_g; Q_g^{LB} and Q_g^{UB} are the lower/upper bounds on q_g; v_b is the voltage at bus b; v_b^{LB} and v_b^{UB} are the lower and upper bounds on v_b; c_g^G is the operating cost (£/MWh) of generator/DER g; $p_{bb'}^L$ and $q_{bb'}^L$ are the real and reactive power flows through line bb'; $S_{bb'}^{max}$ is the apparent power rating of line bb'; θ_b is the voltage phase angle at bus b; G_b^B is the shunt conductance at bus b; B_b^B is the shunt susceptance at bus b.

[38] DERs can be generators, batteries or demand side response (DSR). In this thesis, upward DSR means turning down demand, which has the same effect as turning up generation.

The objective function chosen in this thesis, is to minimise the cost of system balancing for the system operator (3-3)[39], subject to the following constraints: Kirchhoff's current law (KCL) governing real and reactive power balance (3-4)-(3-5); load flow equations (3-6)-(3-7)[40], as well as constraints on voltage phase angle (3-8), the redispatch constraints (3-9)-(3-10), minimum and maximum operating voltages (3-11), generator active and reactive power bounds (3-12)-(3-13), and the line flow constraint (3-14).

$$min \sum_{g \in G} \left(C_g^{\downarrow} p_g^{\downarrow} + C_g^{\uparrow} p_g^{\uparrow} \right) + \sum_{d \in D} V_d^D \left(P_d^D - p_d^D \right) \tag{3-3}$$

$$\sum_{g \in G_b} p_g^G = \sum_{d \in D_b} p_d^D + \sum_{b \in B_b} p_{bb'}^L + G_b^B v_b^2 \tag{3-4}$$

$$\sum_{g \in G_b} q_g^G = \sum_{d \in D_b} Q_d^D + \sum_{b' \in B_b} q_{bb'}^L - B_b^B v_b^2 \tag{3-5}$$

$$p_{bb'}^L = v_b^G G_{bb} + v_b v_{b'} (G_{bb'} \cos(\theta_b - \theta_{b'}) + B_{bb'} \sin(\theta_b - \theta_{b'})) \tag{3-6}$$

$$q_{bb'}^L = -v_b^G B_{bb} + v_b v_{b'} (G_{bb'} \sin(\theta_b - \theta_{b'}) - B_{bb'} \cos(\theta_b - \theta_{b'})) \tag{3-7}$$

$$\theta_{b0} = 0 \tag{3-8}$$

$$p_g^G = p_g^G + \left(p_g^{\uparrow} - p_g^{\downarrow} \right) \tag{3-9}$$

$$p_g^{\uparrow} \geq 0, \; p_g^{\downarrow} \geq 0 \tag{3-10}$$

$$v_b^{LB} \leq v_b \leq v_b^{UB} \tag{3-11}$$

$$P_g^{LB} \leq p_g \leq P_g^{UB} \tag{3-12}$$

$$Q_g^{LB} \leq q_g \leq Q_g^{UB} \tag{3-13}$$

$${p_{bb'}^L}^2 + {q_{bb'}^L}^2 \leq (S_{bb'}^{max})^2 \tag{3-14}$$

where $C_g^{\downarrow}$ is the bid to reduce output; $C_g^{\uparrow}$ is the offer to increase output; $p_g^{\downarrow}$ is the downward re-dispatch variable; $p_g^{\uparrow}$ is the upward re-dispatch variable; V_d^D is the value of lost load (VOLL) of load d; p_d^D is the served load and $(P_d^D - p_d^D)$ is the unserved or 'lost' load. Note: $C_g^{\downarrow}$ and $C_g^{\uparrow}$ can also be represented by a piecewise linear (PWL)

[39] The dispatch positions are already set as part of forward markets, and the role of the system operator is to minimise the cost of redispatch required due to network constraints or to correct imbalances between supply and demand.

[40] The derivation of (3-6) and (3-7) from the rectangular form of KCL can be found in [242].

function in which case rather than a single bid or offer cost, there are multiple costs for different levels of redispatch (as applied in the *Decentralised* model).

The parameters $G_{bb'}$,G_{bb},$B_{bb'}$, and B_{bb} are defined by

$$G_{bb'} = -\frac{g_{bb'}}{\tau_{bb'}}, \quad G_{bb} = \frac{g_{bb'}}{\tau_{bb'}^2}, \quad B_{bb'} = -\frac{b_{bb'}}{\tau_{bb'}}, \quad B_{bb} = \frac{b_{bb'} + 0.5 b_{bb'}^C}{\tau_{bb'}}$$

where $\tau_{bb'} = 1$ except for transformers which are represented as 'lines' with a tap ratio of $\tau_{bb'}$; $b_{bb'}^C$ is the line charging susceptance; and $g_{bb'}$ and $b_{bb'}$ are the conductance and susceptance of line $b_{bb'}$ which are defined by

$$g_{bb'} = \frac{r_{bb'}}{r_{bb'}^2 + x_{bb'}^2}, \quad b_{bb'} = \frac{-x_{bb'}}{r_{bb'}^2 + x_{bb'}^2}$$

where $r_{bb'}$ and $x_{bb'}$ are the resistance and reactance of line $b_{bb'}$.

Inflexible real power demand (P_d^D) can be shed at the VOLL (V_d^D) if it can't be met while satisfying constraints (3-4)-(3-14). Flexible real power demand is modelled as a generator, p_g^G, with associated bid/offer costs ($C_g^{\downarrow}$ / $C_g^{\uparrow}$ respectively) for an increase or reduction to demand within upper and lower bound constraints (3-12).

Reactive power demand (Q_d^D) is modelled is inflexible and must be met within the constraints (3-4)-(3-14) to reach a feasible solution (no shedding of reactive power demand is permitted in the ACOPF model). Generators can provide variable reactive power output within specified upper and lower bounds as specified in (3-13), however the cost of adjusting reactive power output is not included in the objective function (3-3). In further work the cost of adjusting reactive power could be included in the objective function to represent future markets for reactive power. In the case studies provided in this thesis involving ACOPF, generators are modelled as being able to provide between power factors of between 0.85 (lagging) for Q_g^{UB} and 0.95 (leading) for Q_g^{LB}as per grid code [163]. Bus voltage magnitudes (v_b) are set at 1 p.u with lower and upper voltage limits of 0.94 p.u and 1.06 p.u based on the steady state voltage limits (of <132 kV) in operational timescales from [164].

The OATS[165] optimisation software is used to solve the above ACOPF formulation using the non-linear ipopt [166] solver.

3.3.2 DCOPF formulation

The DCOPF is a linearised version of the ACOPF where all voltage magnitudes are fixed and voltage angles are assumed to be small [167]. As a result, reactive power and losses in the network become zero. This approach is more suitable to optimisation of transmission networks which have lower *r/x* ratio's than distribution networks. In this thesis, the objective function of the DCOPF is the same as the ACOPF, however, (3-4) and (3-6) are linearised by removing voltage terms and reactive power and voltage dependent shunt terms are removed:

$$\sum_{g \in G_b} p_g^G = \sum_{d \in D_b} P_d^D + \sum_{b \in B_b} p_{bb'}^L \tag{3-15}$$

$$p_{bb'}^L = B_{bb'} \sin(\theta_b - \theta_{b'}) \tag{3-16}$$

$$\theta_{b0} = 0 \tag{3-17}$$

$$P_g^{LB} \leq p_g \leq P_g^{UB} \tag{3-18}$$

$$p_{bb'}^L \leq P_{bb'}^{max} \tag{3-19}$$

The DCOPF has been implemented using the OATS platform [165] and the cplex [168] linear solver.

3.4 Chapter Summary

In this chapter, the operating principles of the DSO-TSO coordination models to be explored in this thesis: *Centralised, Decentralised* and *Local market,* have been presented in further detail. The models have been developed to optimise the redispatch of generation and DERs to solve MV/HV network constraints and additionally in the TSOs case, to balance supply and demand.

The *Centralised* model is by far the simplest approach and involves a single ACOPF balancing optimisation. In the *Local market,* the DSO uses the ACOPF balancing optimisation as part of a 'traffic light' style mechanism to provide the TSO with an optimal D→T flow (from the DSOs perspective) along with upper and lower bounds for all DERs to respect distribution system constraints. The *Decentralised* model uses the same ACOPF balancing optimisation formulation to produce an aggregated bid/offer curve for the TSO to represent the cost of adjusting the D→T flow.

In the next chapter, the Dec*entralised* and *Local market* models are applied to test networks in a range of case studies, and compared with the theoretically optimal *Centralised* model in terms of computational times and objective function.

Chapter 4:

DSO-TSO Coordination Case Studies

This chapter presents the results and discussion of case studies used to assess the three DSO-TSO coordination models described in chapter 3 of this thesis. Firstly, illustrative examples are provided to demonstrate the allocation of congestion management and system balancing costs between the DSO and TSO in the proposed coordination models. A three transmission bus model is then outlined, and used to compare the performance of the *Centralised*[41], *Decentralised* and *Local market* models on a simplified network. A more detailed 60 bus distribution network model of Cornwall in the south west of England is then used to compare the three DSO-TSO coordination models in a region where high levels of DG are leading to network constraints. Levels of generation and demand for the region are estimated for the year 2030 based on a high uptake of renewable generation and DERs including EVs and HPs. Case studies are carried out on the Cornwall network for single timestep snapshots for a single DSO with zero and non-zero grid import price. The scalability of the *Local market* is then assessed with multiple DSOs and with increasing numbers of nodes. In each case, the models are compared in terms of computational efficiency and system balancing costs[41]. Finally, to capture the influence of competing objectives of the DSO and TSO in the *Local market*, a timeseries analysis is carried out on the Cornwall network for a single DSO.

4.1 Illustrative DSO-TSO cost allocation examples

To illustrate the division of costs between the DSO and TSO for congestion management and system balancing using the coordination models developed in this

[41] The *Centralised* model is included as a benchmark for assessing the *Decentralised* and *Local market* models. The *Centralised* model gives the most accurate system balancing cost as it uses a single T&D network model with no information lost between the DSO and TSO.

thesis, two simple examples are provided. In the first example, a distribution constraint is studied, and in the second example a transmission constraint is also considered. The detailed market operation of the three coordination models are provided in the other case studies in this chapter, but not in these illustrative examples, which are used to illustrate concepts which apply to both the *Local market* and *Decentralised* models. In the following examples, distribution congestion management is carried out by the DSO, and the TSO carries out transmission congestion management and overall system balancing, as is the case with the *Local market* and *Decentralised* models[42].

4.1.1 3-bus network with distribution constraint

Figure 4-1 shows a 3-bus network with a single T-D interface between distribution bus 2 and transmission bus 1. The test system has generators connected to bus 1, 2 and 3 and demands connected to buses 1 and 2.

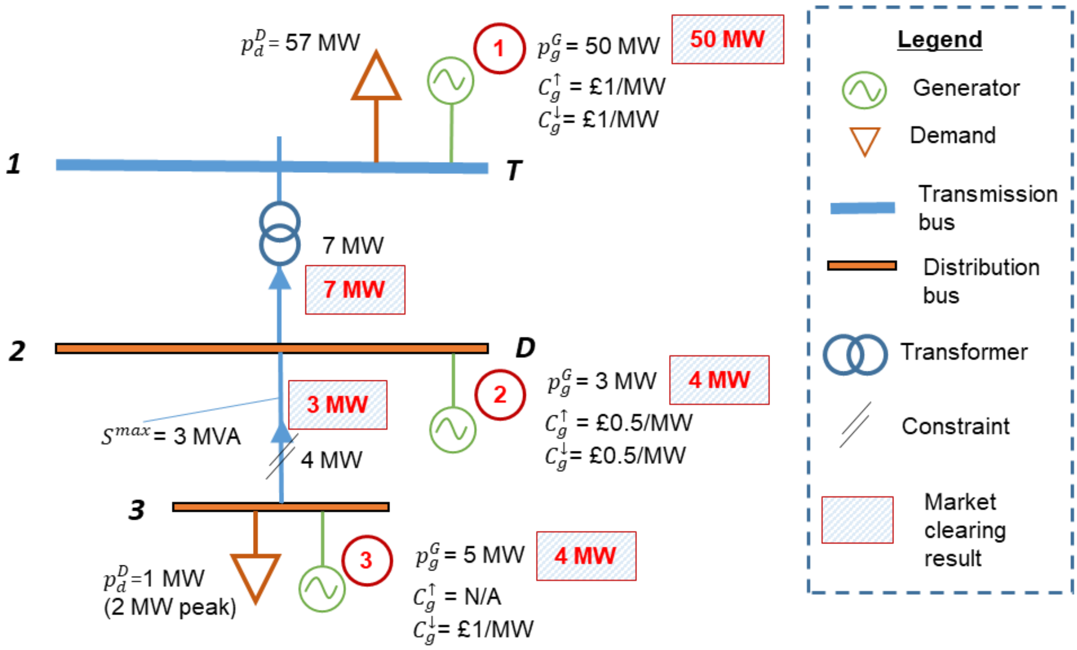

Figure 4-1: Example T-D network with three generators.

[42] In the *Centralised* model, the D and T markets are combined and operated by a single system operator, however, costs could be allocated between the DSO and TSO in a similar fashion to the *Local market* and *Decentralised* models if required.

The set points of the generators and demands are shown in Table 4-1 along with bids and offers to reduce and increase output of each generator.

Table 4-1: 3-bus network parameters

Bus	Demand (p_d^D)	Generator set point (p_g^G)	Bid ($C_g^{\downarrow}$)	Offer ($C_g^{\uparrow}$)
1	57	50	1	1
2	-	3	0.5	0.5
3	1	5	1	n/a

The scenario considered in this example is that of constraint management by the DSO and system balancing by the TSO. Both must be carried out at minimum cost by making the least expensive adjustments to generator set points. Firstly, there is a distribution line constraint that the DSO must solve (by adjusting generation set points) and secondly the overall supply and demand must be balanced by the TSO. In this example, a basic transport model is used to balance supply and demand (ignoring losses, voltage and reactive power) with the exception of a single distribution line rating constraint S^{max} (between distribution buses 2 and 3). All other lines are assumed to be unconstrained. Note the values used in this example are illustrative and are not intended to be realistic representation of a power system.

The market operation rules for the DSO and TSO are as follows. Distribution connected generators provide the DSO set points p_g^G, bids for reduced output $C_g^{\downarrow}$, and offers for increased output $C_g^{\uparrow}$. The DSO carries out distribution system congestion management by adjusting generator set points and passes results to the TSO. The TSO takes these results along with set points p_g^G , bids for reduced output $C_g^{\downarrow}$, and offers for increased output $C_g^{\uparrow}$ for transmission connected generators. The TSO then runs a market to balance total generation and demand as well as solving any transmission constraints.

Results and discussion

The total demand and generation of the submitted market positions are in balance at 58 MW, however, due to the 3 MVA line constraint between buses 2 and 3, the DSO must reduce the output of generator 3 from 5 MW to 4 MW. This creates an imbalance, with the D→T power flow being reduced by 1 MW resulting in demand exceeding generation. To resolve the imbalance, the TSO increases the output of generator 2 by 1 MW as it has the cheapest offer cost of the three generators.

These results, although trivial, are important in considering the allocation of costs between the TSO and DSO in the *Local market* and *Decentralised* models. In these models, the DSO incurs the cost of reducing the output from generator 3 due to the distribution network constraint between buses 2 and 3. However, the action by the DSO has resulted in an imbalance to the TSO, and the TSO incurs the cost of correcting that imbalance by increasing the output of generator 2. In the DSO-TSO coordination models proposed in this thesis, there is no cost imposed on the DSO for adjusting D→T power flow. The distribution constraint and subsequent action by the DSO has resulted in additional costs to the TSO and it could be argued that these costs should all be incurred by the DSO (and not the TSO) to provide a stronger price incentive to resolve the distribution network constraint.

As discussed, it appears that the DSO is causing an imbalance to the TSO, however, when considering the market timescales of the *Local market* and *Decentralised* models, this is not technically the case. The DSO market runs ahead of the TSO and although the DSO reduced its export from the market positions provided, the TSO is provided the adjusted D→T flow by the DSO prior to the TSO market running, and the TSO has no knowledge of the original market positions.

The TSO can adjust the D→T flow provided by the DSO, by accessing the cheapest source of upward flexibility within the distribution network, which in this example is from generator 2. The DSO does not incur the cost of balancing the overall system, however, if actions by the DSO increase that cost, this can provide a signal for more lower cost transmission connected flexibility to balance any distribution system import/export variations.

To prevent the DSO from causing an imbalance to the TSO, the TSO could set the D→T flow in advance such as in the *Shared Balancing Responsibility* SmartNet model (see section 2.2.1.3). However, by doing this the TSO risks limiting access to DERs: for example, in the *Shared Balancing Responsibility* model, the TSO has no direct access to DERs. This can potentially increase congestion management costs for the DSO and system balancing costs for the TSO as illustrated in the following transmission constraint example.

4.1.2 4-bus network with transmission and distribution constraint

This example of a transmission and distribution constraint, illustrated in Figure 4-2, is similar to the first example above, with the addition of a second distribution interface (T-D2) connecting to bus 4 (with generator 4 connected) and a transmission constraint which limits the import from the wider grid (G) to 2 MW. The scenario being considered is the same as the previous example where the DSO must manage distribution constraints and the TSO must manage overall system balancing.

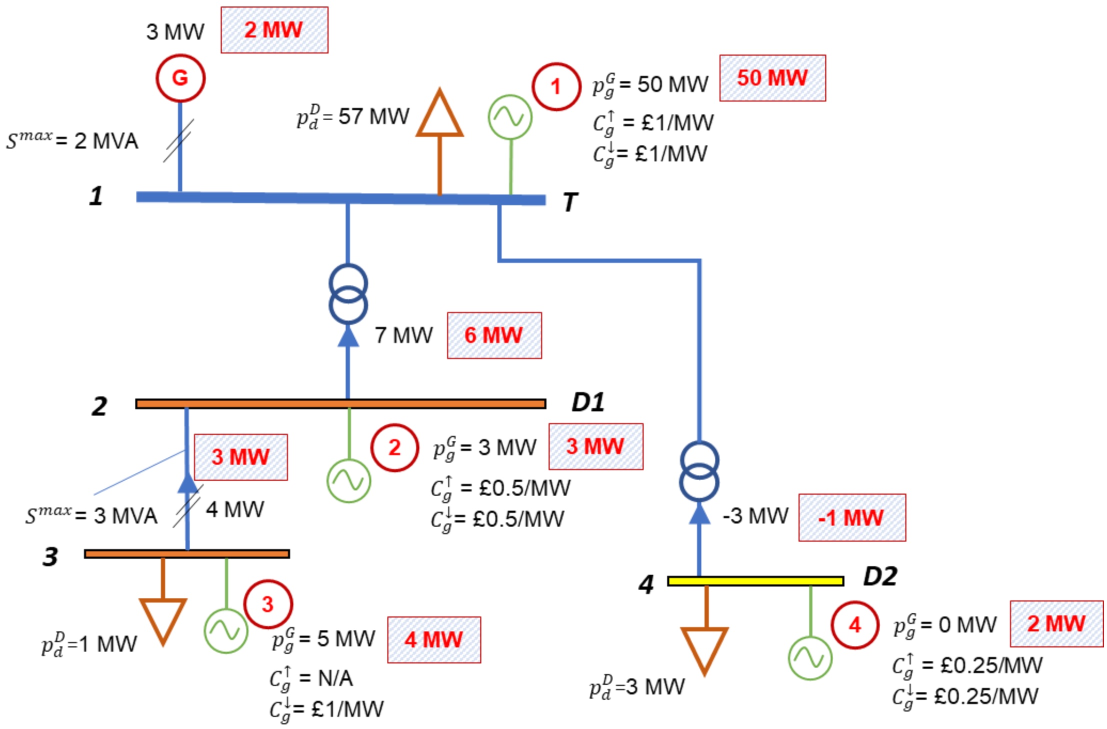

Figure 4-2: Example T-D network with two T-D interfaces.

The set points of the generators and demands are shown in Table 4-2 along with bids and offers to reduce and increase output of each generator.

Table 4-2: 4-bus network parameters

Bus	Demand (p_d^D)	Generator set point (p_g^G)	Bid ($C_g^{\downarrow}$)	Offer ($C_g^{\uparrow}$)
1	57	50	1	1
2	-	3	0.5	0.5
3	1	5	1	n/a
4	3	0	0.25	0.25

Results and discussion

As with the first example, the distribution constraint between buses 2 and 3 results in the requirement to reduce output from generator 3 by 1 MW. In this example, there is a further 1 MW shortage of generation due to the transmission constraint resulting in a reduction of 1 MW grid import to bus 1. With the addition of generator 4 there is a cheaper source of generation than generator 2 which was used to rebalance the network in the previous example.

The reduced output from generator 3 by 1 MW is balanced by an increase in output from generator 4 by 1 MW. Therefore, assuming the distribution systems connected to D1 and D2 are operated by two different DSOs (for convenience referred to henceforth as DSO-1 and DSO-2), DSO-1 is paying for a constraint and DSO-2 is being paid to balance that constraint. The output from generator 4 is increased by a further 1 MW to balance the reduction of grid import due to the transmission constraint. As illustrated, the increased competition for flexibility between DSOs can drive down the costs of flexibility for congestion management and for system balancing for the TSO.

If the TSO had set the D→T boundary flows in advance (assuming they are set at the initial D→T flows prior to DSO adjustments), and then experienced an unexpected imbalance of -1 MW, this could have two unintended effects. Firstly, DSO-1 would pay more to use generator 2 to maintain the prescribed flow across D2→T. Secondly, the TSO would have lost access to generator 4, which was providing the cheapest source of generation to balance both the transmission and distribution constraints. By prescribing D→T boundary flows in advance, the TSO risks losing access to the cheapest sources of flexibility, whereas by allowing the D→T flow to change closer to delivery, the TSO can balance the flow across multiple T-D interfaces and access the cheapest sources of flexibility.

4.2 Three transmission bus model

Having explored the allocation of costs between the DSO and TSO for illustrative examples, case studies are now presented to demonstrate the operation and results of the three models on a three transmission bus model.

The three transmission bus model, adapted from [82], has a T-D interface at each transmission bus which connects to a 6 bus distribution system as shown in Figure

4-3. Buses 1 and 2 have the same distribution network topology connected, as is shown for bus 3 in Figure 4-3. All distribution bus numbers in the three transmission bus model are prefixed with the transmission bus number *N* to which the distribution nodes are connected. For example, bus 11 connects to transmission bus 1, and bus 22 is one of the set of nodes connected to transmission bus 2. All distribution buses (except 11, 21 and 31) have demand, flexible demand and generation connected.

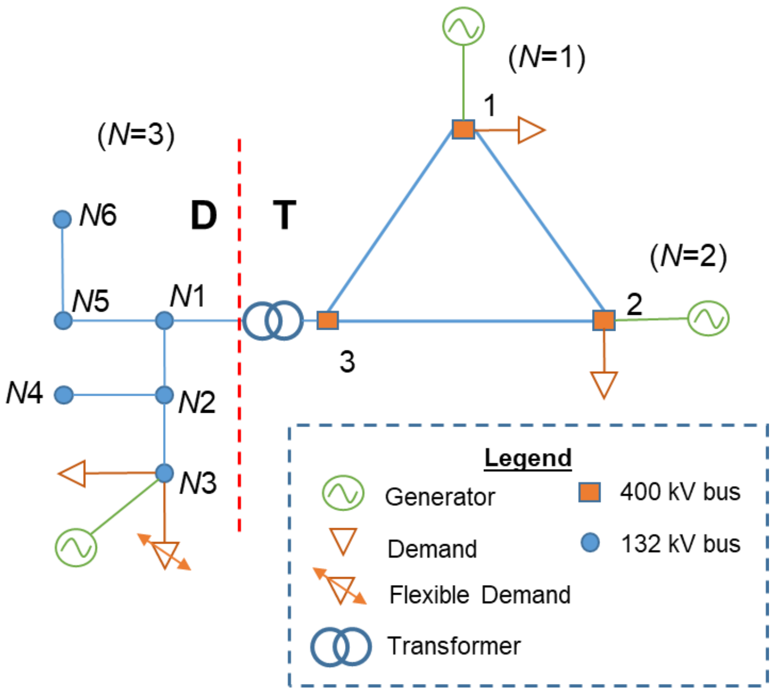

Figure 4-3: Three transmission bus model. D-distribution, T-transmission. N- transmission bus number which prefixes all distribution bus numbers.

Details of the demand, flexible demand and generation market input set points are provided in Table 4-3. These set points would be provided to the market operator at gate closure. In the *Centralised* model there is a single market operator (assumed to be the TSO) solving the T-D system as a single balancing market, whereas in the *Local market* and *Decentralised* models the DSO operates a market first for congestion management and provides results to the TSO at the T-D interface, the TSO market then runs for the transmission system.

For simplicity, each distribution system is identical, i.e., has the same topology and the same levels of demand and generation. Network constraints are not modelled and there is no requirement for congestion management, therefore, in the *Local market* and *Decentralised* models, the DSO only has to aggregate resources to the T-D interface (with no adjustments required to manage distribution constraints), and the TSO will balance supply and demand.

From inspection of Table 4-3, supply and demand are already balanced at transmission level, however each distribution network is exporting 25 MW to the transmission network creating an overall 75 MW generation surplus. Therefore 75 MW of generation turn-down or demand turn-up will be required to balance overall supply and demand. Furthermore, transmission connected generators will pay 30-35 £/MW to turn down (as indicated by negative bids[43]), which means the TSO can profit by paying to turn down the flexible demands (equivalent to an increase in generation) at buses *N*2 and *N*3 where the income from generation turn-down exceeds the cost of the demand turn-down (indicated by the flexible demand bid cost).

Table 4-3: Three transmission bus model: demand, generation, and costs.

			Generation					**Flexible Demand[1]**			
Bus[2]	kV	Inflexible Demand (MW)	Set point (MW)	Upper Bound (MW)	Lower Bound (MW)	Bid[43] (£/ MW)	Offer[43] (£/ MW)	Set point (MW)	Flexibility (MW)	Bid (£/ MW)	Offer (£/ MW)
		P_d^D	p_g^G	P_g^{UB}	P_g^{LB}	$C_g^{\downarrow}$	$C_g^{\uparrow}$	p_g^G	P_g^{UB}	$C_g^{\downarrow}$	$C_g^{\uparrow}$
1	400	350	350	390	0	-30	45	-	-	-	-
2	400	150	150	150	0	-35	50	-	-	-	-
3	400	0	-	-	-	-	-	-	-	-	-
***N*2**	132	70	85	85	0	0.1	0	-10	+10	8	8
***N*3**	132	70	85	85	0	0.1	0	-10	+10	16	16
***N*4**	132	70	85	85	0	0.1	0	-10	+10	40	40
***N*5**	132	70	85	85	0	0.1	0	-10	+10	50	50
***N*6**	132	70	85	85	0	0.1	0	-10	+10	80	80

[1] Expressed in terms of generation. i.e., +10 MW represents 10 MW demand turn down.

[2] The bus prefix *N* represents the distribution system number. As the dispatch in all three distribution systems (N=1,2,3) is the same, the total dispatch will be triple that shown for *N2-N6*.

The DGs connected to buses *N*2-*N*6 are operating at their upper bound. The bid costs for turning down the DGs are very low at £0.1/MW, however, the transmission

[43] In this thesis, positive bids and offers represent costs to the TSO and negative bids and offers represent revenue.

connected generators are willing to pay to be turned down hence they will be the preferred choice for the TSO for turn-down.

4.2.1 Results and discussion

The system balancing costs along with computational time are discussed for each of the three DSO-TSO coordination models in the following sections. In the scenarios modelled, the objective is to balance generation and demand (including flexible demand) in the three transmission bus network at minimum cost. The generation and demand set points, as well as bids and offer costs for adjusting these set points are described in Table 4-3. The following scenarios are modelled with the following assumptions:

- *Centralised* model: the TSO carries out system balancing with a full distribution and transmission network model, adjusting generators and flexible demand connected at both distribution and transmission levels.
- *Local market* model: the DSO prequalifies distribution connected generator and flexible demand using the traffic light mechanism described in section 3.2.2.1. Once prequalified they are managed directly by the TSO, however the TSO does not have visibility of the distribution network.
- *Decentralised* model: the DSO prequalifies, and aggregates distribution connected assets using the aggregated bid/offer curve methodology described in section 3.2.4.2. The TSO can then adjust the D-T flow but does not have visibility of the distribution network.

In all cases it is assumed that the set points, bids and offers of the generation and flexible demand is provided by the market participants at gate closure (at least 1 hour ahead of delivery) and that the DSO and TSO have an accurate forecast of inflexible demand at gate closure. The metrics used to compare the performance of the three coordination models are computational time, and system balancing costs. These metrics quantify the trade-off between the accuracy and scalability of the methods.

A DCOPF with balancing formulation (detailed in section 3.3.2) has been used for the high-level comparison of DSO-TSO coordination schemes on the three transmission bus model. The DCOPF has been implemented using the OATS platform [165] and the cplex [168] linear solver. Computational times report throughout the thesis are for studies conducted using a PC with a 3.3GHz i5 processor with 8GB RAM.

4.2.1.1 Centralised model

In the *Centralised* model, the function of the TSO market is to solve all distribution and transmission constraints, as well as balancing overall supply and demand, using a single balancing market with a full T-D network model. The TSO takes the positions of all DERs, and transmission connected generation, from Table 4-3, and balances supply and demand (there are no network constraints) by adjusting generator and DER set points (also referred to as redispatch) using the system balancing objective function (4-1) subject to DCOPF constraints (3-15) – (3-19).

$$\min \sum_{g \in G} \left(C_g^{\downarrow} p_g^{\downarrow} + C_g^{\uparrow} p_g^{\uparrow} \right) + \sum_{d \in D} V_d^D \left(P_d^D - p_d^D \right) \tag{4-1}$$

where $p_g^{\downarrow}$ and $p_g^{\uparrow}$ represent downward and upward redispatch of generators/DERs. The DCOPF generation and network constraints can be found in section 3.3.2. As line constraints are not modelled in this example, the binding constraints are on generation limits and power balance.

The results of generation and flexible demand redispatch for the TSO market are summarised in Table 4-4. As there is a surplus of 25 MW generation being exported by each distribution network, there is a requirement to reduce overall generation by 75 MW to balance supply and demand.

The generator at bus 2 is turned down by 75 MW, and it is then turned down a further 60 MW (giving 135 MW in total) to balance an increase of 20 MW export from each distribution system due to flexible demand redispatch. The reason for this is that the objective of the TSO market (4-1) is to balance supply and demand at minimum cost (referred to in this thesis as ‘objective function cost’), which is equivalent to maximising profit by adjusting generator/DER output.

Table 4-4: Three transmission bus redispatch: Centralised model.

		Generation		**Flexible Demand**	
Bus[2]	kV	Redispatch (MW)	Cost (£)	Redispatch (MW)	Cost (£)
		$p_g^{\downarrow}$	$C_g^{\downarrow} p_g^{\downarrow}$	$p_g^{\uparrow}$	$C_g^{\uparrow} p_g^{\uparrow}$
1	400	0	0	-	-
2	400	-135	-4725	-	-
3	400	-	-	-	-
***N*2**	132	0	0	+10[1]	80
***N*3**	132	0	0	+10[1]	160
***N*4**	132	0	0	0	0
***N*5**	132	0	0	0	0
***N*6**	132	0	0	0	0
Objective function cost: -£4005, Time: 0.1s					

[1]In terms of generation. i.e., +10 MW represents 10 MW demand turn down.

[2] The bus prefix *N* represents the distribution system number. As the dispatch in all three distribution systems (N=1,2,3) is the same, the total dispatch will be triple that shown for *N*2-*N*6.

The generator at bus 2 is willing to pay the TSO £35/MW to turn down (note it is common for gas generators in the BM to pay to be turned down based on fuel cost saving), and there are flexible demands that can balance this action at a cost of £8/MW and £16/MW at distribution buses *N*2 and *N*3. Therefore, the TSO maximises the demand turn down at buses *N*2 and *N*3 (totalling 20 MW per distribution system) as this allows the TSO to gain maximum revenue from turning down the generator at bus 2 by a further 60 MW in total. The flexible demands at buses *N*4-*N*6 were not activated due to their offers being above £35 meaning it would cost more to turn them down than the income received by the TSO for the corresponding turn down of generators as buses 1 or 2.

The objective function cost of -£4005 represents a profit for the TSO by receiving £4725 from the generator at bus 2 to turn down by 135 MW, minus the cost of £720 (3x£240) to turn down flexible demands at buses *N*2 and *N*3 (for all 3 distribution systems) by 60 MW in total. The actions by the TSO resulted in an increase in power flow from D→T of 20 MW per T-D interface. If the TSO did not have access to flexible demand at distribution, and in the absence of any DSO-TSO coordination, the flexible demands at distribution would not be redispatched. This would have reduced the profit for the TSO from £4005 down to £2625[44], a reduction of 34%.

The *Centralised* model gives the optimal result due to having perfect information of all bids and offers of flexible demands and generation located at distribution level. Furthermore, DCOPF of the three transmission bus model solves extremely quickly (under 1 second) which shows that for such a simple example there is no benefit to gained from using the more complex *Local market* and *Decentralised* models. However, as discussed in section 2.2.4, the *Centralised* model does not provide optimal allocation of responsibility between the DSO and TSO, and for larger realistic T-D networks the computation time and modelling complexity of the *Centralised* model would increase significantly.

The operation of the *Local market* and *Decentralised* models is now demonstrated to give the reader an understanding of how they operate in a relatively simple example.

4.2.1.2 Local market

In the *Local market* model, rather than the TSO operating a market for the entire T-D network, the DSO manages distribution constraints in the traffic-light style congestion market illustrated in Figure 3-4, and the TSO manages transmission network congestion and overall system balancing.

DSO congestion market

In this simple three bus example, where there are no distribution constraints, the DSO congestion market operates in the ‘green’ state, with no need for any adjustments to DER upper/lower bounds or set points.

The DSO market, outlined in 3.2.2, operates as follows: The DSO uses the system balancing objective function (4-1), with DCOPF constraints for all DERs at upper and lower bounds based on the DER market positions in Table 4-3. In this example, as there are no network constraints, there is no requirement for adjustments to the DER set points, or upper/lower bounds and the cost to the DSO for congestion

[44] Without any redispatch of flexible demand, the total D→T flow for all 3 distribution systems is 75 MW (3 x 25 MW) rather than 135 MW with demand turn down. In this case, the TSO only turns down generator 2 by 75 MW to balance supply and demand for which the TSO is paid £2625.

management is zero. The optimal D→T power flow, is 25 MW export, based on the DSO carrying out no adjustments to the original set points.

TSO balancing market

After the DSO market runs, the DSO passes the prequalified DER positions, which in this example are unchanged from the original DER positions, to the TSO. The DERs are all added to the T-D interface (bus *N*1 in Figure 4-3) along with the aggregated demand $\sum_{d \in D} p_d^D$ of 350 MW per DSO.

Along with the DERs and aggregated demands for at each T-D interface, the TSO receives transmission connected generation set points p_g^G, and their respective bid and offer costs $\mathrm{C}_g^{\downarrow}$ and $\mathrm{C}_g^{\uparrow}$. The TSO uses the system balancing objective function (4-1), with DCOPF constraints to minimise the cost of system balancing and transmission system congestion management. In the *Local market* the TSO passes dispatch instructions directly to the DERs and a DSO redispatch is not required as in the *Decentralised* model.

The redispatch in the *Local market* model, shown in Table 4-5, matches that of optimal results from the *Centralised* model but with increased computational time.

Table 4-5: Three transmission bus dispatch: Local market.

		Generation		**Flexible Demand**	
Bus[2]	kV	Redispatch (MW)	Cost (£)	Redispatch (MW)	Cost (£)
1	400	0	0	-	-
2	400	-135	-4725	-	-
3	400	-	-	-	-
***N*2**	132	0	0	+10[1]	80
***N*3**	132	0	0	+10[1]	160
***N*4**	132	0	0	0	0
***N*5**	132	0	0	0	0
***N*6**	132	0	0	0	0
Objective function: -£4005, Total time: 2.3 s[1]					

[1]Time for single DSO (assuming they can operate in parallel) and the TSO

In this example, there are no distribution constraints and DER bounds are not modified in the DSO congestion market. Therefore, adding DERs directly to bus *N*1 in the *Local* *market* results in exactly the same dispatch by the TSO as in the *Centralised market* where the DERs are modelled in their original network locations.

The total time in Table 4-5 includes all three DSOs which would operate in parallel. The time to operate the DSO market in the *Local market* model includes a balancing DCOPF for the upper and lower bounds of the DERs, then a further DCOPF validation of any adjustments to the DER bounds. At around 0.6 s per DCOPF this results in the time of 1.8 s per DSO in this example.

The division of costs between the DSO and TSO has been discussed in section 4.1 and is discussed in more detail in subsequent sections of this thesis. That being said, it should be noted that the redispatch of generator 2 resulted in a profit £4725 to the TSO, but this required flexible demand redispatch by the DSO at a cost of £240 per DSO. With separate TSO and DSO markets, there is a risk that the TSO carries out actions at the expense of the DSO or vice versa. However, in the *Local market and Decentralised* models, the TSO pays for the adjustments from the optimal D→T flow and not the DSO. The DSO only pays for DER adjustments to resolve distribution constraints in the DSO market as shown in the illustrative examples in section 4.1.

4.2.1.3 Decentralised model

In the *Decentralised* model, rather than the TSO operating a market for the entire T-D network, the DSO manages distribution constraints, and the TSO manages transmission network congestion and overall system balancing. The steps involved in the *Decentralised* model are summarised as follows (for more detail refer to section 3.2.4): the DSO receives positions from each DERs and runs the congestion market to resolve distribution constraints; then the DSO provides an aggregated bid/offer curve to the TSO representing the cost to the DSO of adjusting D→T flow across the T-D interface; the TSO then runs the transmission level market incorporating the aggregated bid/offer curve from the DSO; and finally the DSO dispatches DERs according to the prescribed D→T flow by the TSO. In this example, there are three T-D interfaces, and it is assumed there are three DSOs, although as each distribution system is identical, the results are the same for each DSO. The results of the *Decentralised* model for each DSO are as follows.

DSO congestion market

The DSO congestion market operates in the same way as in the *Local market* and the optimal, maximum and minimum D→T flow is calculated as follows:

1. The DSO takes market positions of distribution connected generators and flexible demands (at buses N1-N5) shown in Table 4-4.
2. Using system balancing objective function (4-1), and DCOPF constraints, the optimal D→T flow, F_S, is determined as +25 MW (export) per distribution system and the optimal objective function cost, O_S corresponding to this D→T flow, is £0. There are no distribution constraints and T-D flow comes at zero cost, hence the optimal market result for the DSO is to make no adjustments to DERs.
3. The maximum and minimum D→T active power flow, F^{UB} and F^{LB} are +75 MW and -400 MW, respectively. F^{UB} corresponds to all generators at maximum output (which they were already set at) plus 50 MW from all five flexible demands at their upper bounds (10 MW x 5). F^{LB}corresponds to the required import to meet all demands (70 MW x 5) when all generators are at their lower bounds (0 output) and flexible demands at lower bounds (-10 MW x 5).

Aggregated bid/offer curve

In the *Decentralised* model, an aggregated bid/offer curve is constructed (using the methodology in section 3.2.4.2) to represent the cost of adjusting the D→T power flow. The following results are presented for an aggregated bid/offer curve with z=2 evenly distributed points, but the same process can be repeated for higher values of z (z=3,4,5…) to improve the accuracy of the results:

1. The bid points for decreased D→T flow ($F_n^{\downarrow}$) are:

$$F_n^{\downarrow} = F_S - \frac{(F_S - F^{LB}) \times n}{z}:\ 1 \geq n \geq z \quad (4\text{-}2)$$

$$F_{1,2}^{\downarrow} = (-187.5, -400)\ \text{MW}$$

   Increases in F_n from F_s are offer points ($F_n^{\uparrow}$):

$$F_n^{\uparrow} = F_S + \frac{(F^{UB} - F_S) \times n}{z},:1 \geq n \geq z \quad (4\text{-}3)$$

$$F_{1,2}^{\uparrow} = (50, 75)\ \text{MW}$$

2. Using system balancing formulation (4-1), and DCOPF constraints, the costs, $O_n^{\uparrow}$ and $O_n^{\downarrow}$, is calculated for the DER adjustments (including flexible demand) to achieve each value of $F_n^{\uparrow}$ and $F_n^{\downarrow}$ respectively:

$$O_{1,2}^{\downarrow} = (21.2, 42.5)\ £$$

$$O_{1,2}^{\uparrow} = (440, 1940)\ £$$

The aggregate bid and offer curves for z=2 evenly distributed points, plotted in Figure 4-4, are passed to the TSO as a PWL function to represent the cost of adjusting the D→T flow across the T-D interface from the optimal D→T flow, F_S.

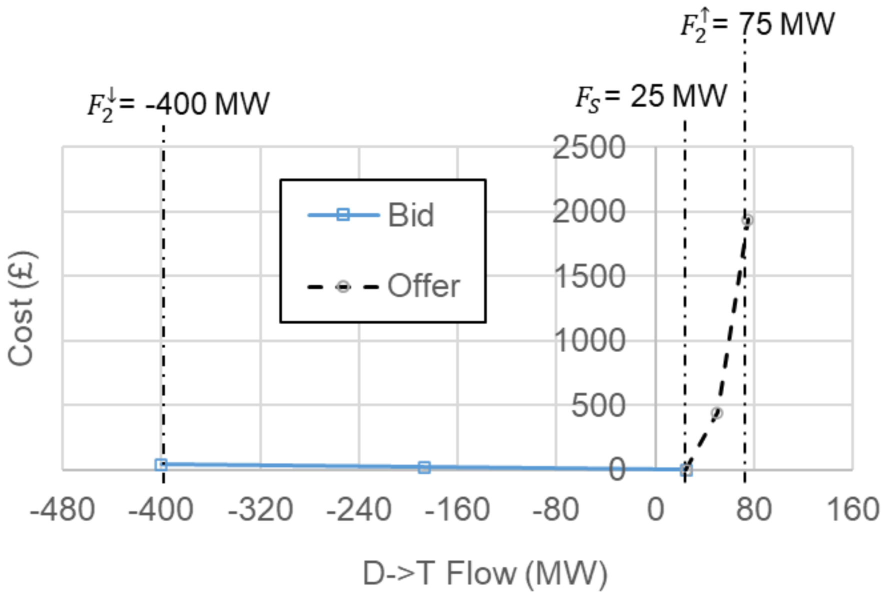

Figure 4-4: Aggregated bid/offer curves for z=2 evenly distributed points.

TSO balancing market and DSO redispatch

The TSO uses the system balancing formulation (4-1), with DCOPF constraints to minimise the cost of system balancing and transmission system congestion management.

As well as the aggregated bid/offer curves representing the cost of adjustments to D→T flow set point, F_S, for the DSO at each T-D interface, the TSO receives transmission connected generation set points p_g^G, and their respective bid and offer costs $C_g^{\downarrow}$ and $C_g^{\uparrow}$. The results of the TSO balancing market are presented in Table 4-6 for DSO aggregated bid/offer curves with z=2 and z=3 evenly distributed points.

The objective function cost in Table 4-6 represents the total system balancing cost for the TSO which includes the cost of DSO redispatch. This allows direct comparison with the total system balancing cost in the *Centralised* model. As is this case in the *Centralised* and *Local market* models, the TSO reduces the output from generator 2 by 75 MW to balance supply and demand and then reduces output further (by 75 MW for z=2 and 58 MW for z=3) with a subsequent turn-down in flexible demand in the distribution system. However, in the *Decentralised* model, the TSO income is reduced compared to the *Centralised* and *Local market* models which give a TSO profit of £4005.

Table 4-6: Three transmission bus redispatch: Decentralised model

		Generation				**Flexible Demand**			
Bus	kV	Redispatch		Cost (£)		Redispatch		Cost (£)	
		z=2	z=3	z=2	z=3	z=2	z=3	z =2	z=3
1	400	0	0	0	0	-	-	-	-
2	400	-150	-123	-5250	-4305	-	-	-	-
3	400	-	-	-	-	-	-	-	-
N2	132	0	0	0	0	+10	+10	80	80
N3	132	0	0	0	0	+10	+6	160	96
N4	132	0	0	0	0	+5	0	200	0
N5	132	0	0	0	0	0	0	0	0
N6	132	0	0	0	0	0	0	0	0
z=2: Objective function cost: -£3930, Total time: 5.3s[1]									
z=3: Objective function cost: -£3777, Total time: 6.4s[1]									

[1]Time for single DSO (DSO Market + PWL + Redispatch) and the TSO

For the three bus transmission network, the aggregated bid/offer curve provides sub-optimal results for overall system balancing cost for a small number of points (z=2 and z=3). The revised D→T flow, F_R determined by the TSO during system balancing depends on the intersection between the marginal TSO income (from generator 2), and the marginal costs for adjusting the D→T flow, as illustrated in Figure 4-5. For z=2, this occurs at 50 MW, for z=3 this occurs at 41 MW, whereas the optimal result (as determined in the *Centralised* model), is at 45 MW. The cost of these suboptimal results is a reduction in the TSO profit of 1.9% and 5.7% for z=2 and z=3 respectively compared to the *Centralised* model. In this example, z=2 resulted in a greater profit to the TSO than z=3, but z=3 has a D→T power flow closer to the optimum.

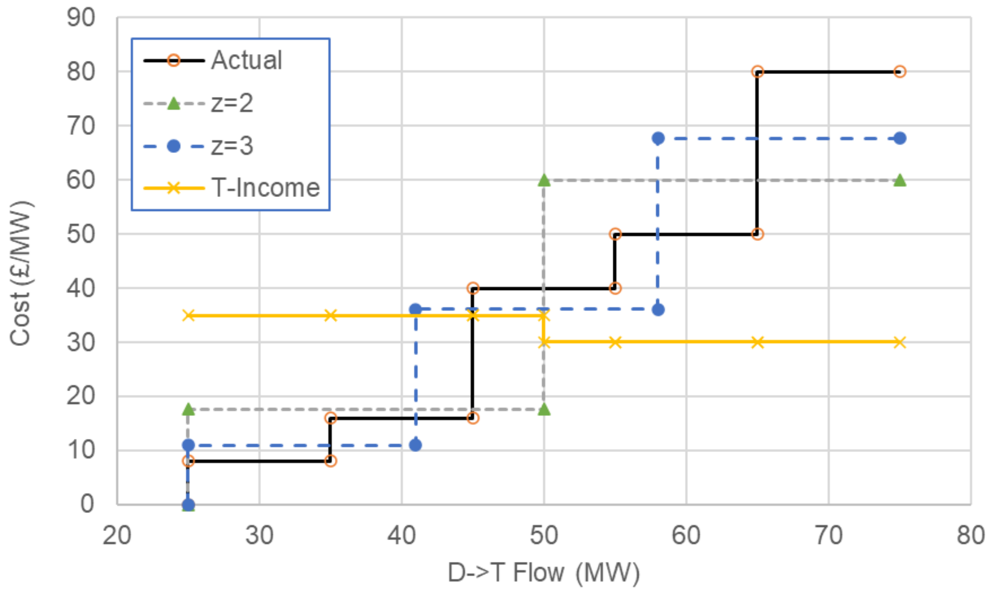

Figure 4-5: Decentralised model: Marginal costs for D→T Flow adjustments calculated from DSO aggregated bid/offer curves with 2 and 3 points (z=2 and z=3), 'Actual' bid curve for flexible demands N2-N5, and TSO income bid curve (labelled as T-income).

One potential solution to the problem of the suboptimal results using the aggregated bid/offer curves is more intelligent selection of the points on the curves. If the points were selected based on the 'Actual' bid curve shown in Figure 4-5, e.g., for z=3, if the first point is set at 35 MW, and the second is set at 45 MW, the resulting system balancing objective function cost is -£4005 which matches the *Centralised* model. While this method is adequate for a simple unconstrained network such as the three transmission bus model, it would not be sufficient when the DSO bid curve does not exactly follow the bid curve of the flexible demands or generation. In this case, using more points (z>3) will eventually converge on the optimum PWL function[45] to accurately represent the cost of adjusting the D→T power flow. However, increasing z comes with a computational cost and a trade off needs to be reached between tractability and providing a PWL function that minimises system operating costs.

[45] The PWL function is the mathematical representation of the aggregated bid/offer curve. The terms can be considered synonymous and in the remainder of the thesis, PWL points is frequently used in reference to the points on the aggregated bid/offer curve.

Computational time with number of PWL points

The total solving time for the *Decentralised model* is significantly higher than the *Centralised* model by 2 orders of magnitude even with z=2, which represents the minimum number of PWL points. However, it is important to recognise how the total time breaks down between the three DSOs and the TSO. This is shown in Table 4-7 where the DSO times are provided for a single DSO and the total time is for a single DSOs and the TSO.

Table 4-7: Decentralised: computation times with number of PWL points, z.

		Time (s)				
z	DSO Market[1]	DSO PWL[1]	TSO	DSO Redispatch[1]	Total[2]	**Objective Function (£)**
2	1.2	2.8	0.6	0.7	5.3	-3930
3	1.2	3.9	0.7	0.6	6.4	-3777
4	1.2	5.1	0.7	0.6	7.6	-3930
5	1.2	7.0	0.7	0.6	9.5	-4005

[1]Time for a single DSO.
[2]Time for single DSO (DSO Market + PWL + Redispatch) and the TSO

The time for the DSO market includes a balancing DCOPF for the upper and lower bounds of the DERs. The DSO market runs once and the time for this does not increase with the number of PWL points z. The main computational burden is on the DSO to produce the PWL function which involves running 2 DCOPFs (bid and offer) for each point.

Thus, in this example, with every increase in z, the DSO PWL time increases by between 1 and 2 seconds. For the small number of DERs this example, the time for the TSO optimisation is higher for the *Decentralised* model than in the *Centralised* optimisation. This is because the PWL function in the *Decentralised* model increases the modelling complexity compared to the *Centralised* model which uses simpler bid/offers to represent generator/DER costs. However, for a large number of DERs represented by a single PWL function, the computational time for the TSO could be lower in the *Decentralised* model.

For multiple DSOs, the DSO operations will be done in parallel, in which case the time for three DSOs would equal the total time for a single DSO as in Table 4-7. In terms of the trade-off between computational time and system balancing cost (which is also referred to as objective function cost), in this simple example, going from z=2 to z=5 almost doubles the computational time and increases TSO profit by 1.9%. This is a relatively small gain in operating profit for a large cost in computational time. In more realistic networks with upwards of tens of thousands of buses, the computational time in this method could become problematic. To take 7 s to produce an aggregated bid/offer curve with five points using DCOPF on a simple 3-transmission bus model could mean taking several minutes to do so using ACOPF on a realistic distribution model. The time taken must be within operational timescales to be of practical use: this will be assessed on the 60 bus Cornwall distribution network later in this chapter.

4.2.1.4 Summary of results

The total system balancing (objective function) cost and computational times of the three DSO-TSO coordination models when applied to the three transmission bus network are shown in Table 4-8. As previously discussed, in this example the TSO is able to generate profit, represented by a negative cost, hence the optimal result (as obtained by the *Centralised and Local market* models) is a profit of £4005.

Table 4-8: Three transmission bus: objective function cost and solving time for DSO-TSO coordination models.

	Centralised		**Decentralised**[1]		**Local Market**	
	Objective function cost (£)	Solve time (s)	Objective function cost (£)	Solve time (s)	Objective function cost (£)	Solve time (s)
TSO	-4005	0.1	-3930	0.6	-4005	0.1
DSO[2]	-	-	0	4.7	0	2.1
Total[3]	-4005	0.1	-3930	5.3	-4005	2.3

[1]Results for aggregated bid/offer curve with 2 points (z=2)

[2]Results for single DSO

[3]Assuming DSOs are run in parallel in the *Decentralised* and *Local market* models

Due to not including any network constraints, this example does not provide a full demonstration of the DSO market in the *Local market and Decentralised* models, However, it does demonstrate the increased complexity of the *Decentralised* model in constructing the aggregated bid/offer curve, and the relative simplicity of *Local market*, where the DSO prequalifies DER positions, which are then dispatched directly by the TSO. From the results of Table 4-8, the *Local market* outperforms the

Decentralised model, both in achieving the optimal result (matching the *Centralised* solution) and in less than half the time of the *Decentralised* model.

A further disadvantage of the *Decentralised* model is that it requires DSO redispatch after the TSO market which introduces a further stage of communication between the TSO and DSO. Furthermore, inaccuracies in the aggregated bid/offer curve in representing the cost of adjusting the D→T flow can result in a suboptimal objective function cost for the *Decentralised* model, as was the case in this example.

The implementation of these coordination models in the GB electricity system poses significant regulatory challenges. These include modification of the BM trading arrangements [169] to incorporate distribution system constraint management, either by the TSO in the *Centralised* model or by the DSO in the *Decentralised* and *Local market* models. In all three coordination models, changes would need to be made to the connection agreements of DERs to enter competitive balancing marketplaces for offering flexibility to the DSO and/or TSO. Changes could be required to the use of system charges, levied by the DNOs and NGESO [170] to account for changes to DER connection types and the provision of flexibility in the proposed models.

The technical challenges to be overcome for applying these models are numerous: the *Centralised* model would require the TSO to substantially increase their technical capabilities from operating the transmission system to operating the entire distribution and transmission networks. In the *Decentralised* and *Local market* models, DSOs would need to significantly advance their technical capabilities from a 'fit and forget' approach to operating distribution network congestion management markets. All models will require the widespread adoption of ICT including communication and network monitoring down to 11 kV. Full network models would be required down to 11 kV which is a major challenge given there are 230,000 secondary substations in GB. Furthermore, the DSO and/or TSO must potentially dispatch tens to hundreds of thousands of DERs and model large networks with potentially hundreds of thousands of nodes. There will be a requirement for a high level of automation of dispatch instructions and network optimisation, which could require faster alternatives to the ACOPF approach used in this thesis along with probabilistic techniques to forecast generation and demand at a significantly higher granularity than is currently practised.

In summary, the three transmission bus model has been useful in providing a high-level comparison of the three DSO-TSO coordination models. The following observations have been made in relation to the three transmission bus case studies:

- The aggregated bid/offer curve approach applied in the *Decentralised* model is the most computationally expensive.
  - There is a trade-off between computational time and optimality in selecting the number of points in the aggregated bid/offer curve.
  - Intelligent selection of the points on the bid curve could reduce the number of points required for an accurate solution. However, this must be assessed on a constrained network where the aggregated bid/offer curve would not match the bid curve of the DERs.
- Both the *Decentralised* and *Local market* models take significantly longer to solve than the *Centralised* model.

In the three transmission bus model, network constraints were not binding and a DCOPF was applied. As the size of distribution networks and number of DSO's increases, the parallelisation of the DSOs optimisation may reduce the gap in computational times between the *Local market/Decentralised* and *Centralised* models. However, this will depend on how tractable these coordination methods are, given they both involve several OPF runs either to construct the aggregated bid/offer curve in the *Decentralised* model or to do the upper and lower bound validation in the *Local market.* The performance of the three DSO-TSO coordination models in managing distribution constraints will now be assessed using ACOPF on a larger distribution network.

4.3 The Cornwall Network

To assess the performance of the TSO-DSO coordination models on a larger scale, a 60 bus model has been developed based on part of the distribution network in Cornwall in the south west of England. A representation of the network overlayed on a map of the area is shown in Figure 4-6. The Cornwall region has been selected due to being export constrained with high levels of DG including solar PV, wind, and energy from waste (EfW). The system operating costs and competition for procuring flexibility between the DSO and TSO can therefore be compared for the three DSO-TSO coordination models in a highly constrained region.

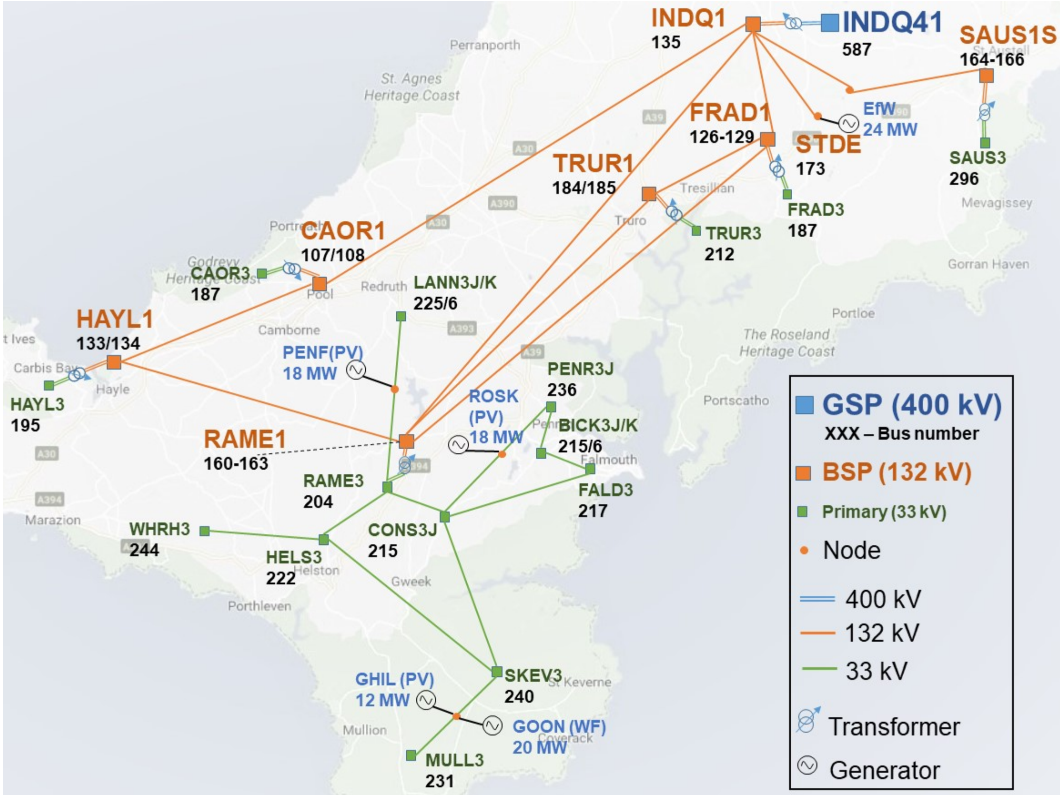

Figure 4-6: Schematic of Cornwall network, EfW - Energy from Waste Plant, WF - Wind Farm, BSP – Bulk Supply Point, GSP – Grid supply point.

The network model in Figure 4-6 has been developed using data in the long term development statement of the DNO [16]. It contains a 400 kV grid supply bus, connected to a ring of 132 kV distribution network. There are 19 transmission buses at 132kV and 33 distribution buses within the Rame network. Six BSPs 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 included in the model, along with the grid supply point (GSP) transformer, and are used to calculate the '($\mathcal{N}$-1)'[46] firm and reverse capacities in Table 4-9 and Table 4-10. At Rame, the 33 kV network is modelled, and demand and generation are aggregated to the 33 kV side of the eleven primary (33 kV / 11 kV) substations.

[46] $(\mathcal{N}-1)$ means a single circuit outage. The required magnitude of grouped demand that must be secured after a single circuit outage is defined for distribution networks in the P2/7 security of supply recommendation [153].

4.3.1 T-D interface for division of responsibility between TSO and DSO

In the Cornwall network, the T-D interface has been set at the BSPs where the voltage is stepped down from 132 kV to 33kV. In practice, the T-D interface is the point at which responsibility for operation and ownership passes between the transmission and distribution network operators/owners, which in England is at the GSPs. However, the 132 kV network in Cornwall is connected in a ring, and power flows in parallel between the 132 KV ring as well as between GSPs[47], making it unrealistic to model individual GSP interfaces in isolation as required in the *Local market and Decentralised* DSO-TSO coordination models. The T-D interface has been set at the BSP transformers and each 33 kV network can be modelled independently as generally they are operated radially with a single interface at each BSP. There are normally open points which can link 33 kV networks which are assumed to remain open in this work.

In the *Decentralised* and *Local market* models, both the TSO and DSO include the BSP transformer limits in their optimisation and in the 'single DSO' case studies a single T-D interface (at Rame BSP) is managed using the *Decentralised* and *Local market* models.

4.3.2 Demand and generation Inputs

Table 4-9 and Table 4-10 describe existing peak demand and embedded generation characteristics of the network, as well as how these characteristics may change under a modelled 2030 scenario from the National Grid Future Energy Scenarios (FES) [171]. 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 HP integration. The CR scenario was chosen to assess the performance of the DSO-TSO coordination models as it provides the highest anticipated levels of DERs out of the FES scenarios.

[47] This is not shown in Figure 4-6 however the schematic network of the wider Cornwall network [243], [244] shows that INDQ1 also connects to a 132 kV ring which runs in parallel to the 400 kV transmission network.

Table 4-9: Cornwall bulk supply point demand headroom : current and 2030 Community Renewables scenario, MVA; data: [16], [171].

BSP	Firm Capacity[1]	2018 Peak Demand	2018 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 ($\mathcal{N}$-1) secure transformer capacity for group demands greater than 60 MW. For example, the firm capacity for Truro is from one of the two Truro BSP transformers, due to group demand being above 60 MW. This is a simplified approximation of the P2/7 security of supply recommendation [172] which is the distribution security of supply standard in GB.

[2]Headroom is calculated from Firm Capacity minus Peak Demand (as in [25]). This does not include minimum embedded generation which would increase demand headroom.

[3]2030 Demand Estimate for Community Renewables scenario [171].

Table 4-10: Cornwall bulk supply point generation headroom : current and 2030 Community Renewables scenario, MVA; data: [25], [171].

	Reverse Capacity[1]	2018 Gen Capacity	2018 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 ($\mathcal{N}$-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 minus Gen Capacity (as in [25]). 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 [171].

The capacity of each generation and flexible demand technology included in the 2030 CR scenario is shown in Table 4-11.

Table 4-11: Cornwall generation and flexible demand by technology[1], 2030 Community Renewables scenario MW; data: [171], [16].

BSP	PV	Wind	Firm[2]	Battery	DSR[3]
Rame	195.8	59	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]All new EV and HP 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.

4.3.3 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 of course a high level of uncertainty around predicting the price of electricity in 2030 and no attempt is made to do so in this thesis. Two price cases are developed to provide alternative scenarios for flexibility costs from DSR and generation:

1. Cheap 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.

Price data for each of these cases is outlined in Table 4-12. Note these prices are for illustrative purposes, not to estimate realistic balancing costs. The positive prices in Table 4-12 ensure that the DSO (whose objective function is represented by (4-1)) 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. In the examples considered, all bids and offers are positive in the DSO market and 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 4-12: DER pricing: Cheap curtailment and Cheap DSR cases, £/MWh.

	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

[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 HPs and EVs.

DERs with 'non-firm' ANM connections have not been modelled in this thesis as generators may be discouraged from the uncertain return in investment if entering an ANM scheme [34] and the DSO markets proposed in this thesis provide an alternative to ANM connections where DERs are compensated for curtailment.

ANM connections could be included in the DSO-TSO coordination models, however this would add further complexity. Those with ANM connections would be curtailed at zero cost based on their principle of access agreement [51], however there could be regulatory challenges associated with some generators having existing non-firm ANM connections and other newer connections being compensated in the DSO market. In the GB transmission system, all generators receive 'firm' connections and are compensated in the BM if curtailed, rather than the mixture of firm and non-firm connections which exist at distribution level.

4.4 Case studies for DSO-TSO coordination model comparison

To effectively compare the coordination models, the performance of the three DSO-TSO coordination models will be assessed for a single snapshot of maximum generation with a single DSO managing the T-D interface at the RAME1 bulk supply point (BSP). This is carried on the Cornwall network for the following case studies:

- Zero grid cost: to represent a scenario where the TSO has no requirement for DER flexibility to balance supply and demand in the wider grid.
- Non-zero grid cost: to represent a scenario where it is cost effective for the TSO to access DER flexibility.

The results and discussion of these case studies is presented in the following.

4.4.1 Results: single DSO snapshot with zero grid cost

For comparison of the three coordination models on a constrained distribution network, ACOPF with balancing is carried out for a snapshot of 2030 maximum demand and generation for the CR scenario, summarised in Table 4-9 and Table 4-10 respectively, with 'Cheap Curtailment' costs from Table 4-12. The Cornwall network is export constrained in the case of maximum generation due to the generation capacity minus the maximum demand exceeding the reverse capacity of ($\mathcal{N}$-1) transformers (see Table 4-9) for most of the T-D interfaces including Fraddon, Truro, Rame and St Austell. The results of the *Decentralised* and *Local market* models are considered for a single DSO coordinating the T-D interface between the Rame 33kV network and the 132 kV transmission network. The snapshot is modelled with a zero grid balancing cost representing the case where the TSO has no requirement to adjust DERs to balance supply and demand in the wider grid. In the *Decentralised* and *Local market* models, the DER bids/offers are the same in the DSO market as in the TSO market, which in turn are the same as those used in the *Centralised* model. In all cases, the OATS[165] optimisation software is used to solve ACOPF formulation from section 3.3.1 using the non-linear ipopt [166] solver.

4.4.1.1 Summary of results: zero grid cost

The results of the ACOPF with system balancing for each of the three DSO-TSO coordination models are summarised in Table 4-13.

Table 4-13: Maximum generation snapshot (zero grid cost): objective function and solving time for DSO-TSO coordination models with single DSO.

	Centralised		**Decentralised**[1]		**Local Market**	
	Objective function cost (£)	Solve time (s)	Objective function cost[2] (£)	Solve time (s)	Objective function cost[2] (£)	Solve time (s)
TSO	2374	4.5	1801.5	2	1800.8	2.8
DSO	-	-	570.9	18.7	570.9	6.1
Total	2374	4.5	2372.4	20.7	2371.7	8.9

[1]Results for aggregated bid/offer curve with 2 points.

[2]The objective function cost for the DSO is the congestion management cost for Rame, and the objective function cost for the TSO is the congestion management cost for the remaining five BSPs plus overall system balancing cost.

In each of the three coordination mechanisms, the redispatch actions by the SO[48] were to turn down DERs due to the BSP transformer constraints. As the grid balancing price is set to zero, the TSO did not adjust DER output for grid balancing. The total objective function cost for congestion management and system balancing for the three models represents the cost of reducing output of wind, PV, and Firm generation in the constrained regions of Fraddon, Truro, Rame and to a lesser extent St Austell (where only the cheaper option of reducing output of Firm generation is required). In all cases, the Cornwall network exports 439 MW to the grid and 407 MW of generation is curtailed due to ($\mathcal{N}$-1) BSP transformer export constraints shown in Table 4-10.

As this case study only demonstrates a single DSO, only the Rame network (connecting to the RAME1 BSP) is modelled at 33 kV. For the other five BSPs, the aggregated demand and generation values in Table 4-9 and Table 4-10 are added to the T-D interface and BSP transformer constraints are modelled as part of the TSO balancing model. Therefore, the DSO market for prequalification and aggregation of DERs in the *Decentralised* and *Local market* are only applied to the Rame network.

Features specific to the *Decentralised* and *Local market* models are discussed further in the following sections, however, some initial observations on the results in Table 4-13 are now provided as an overview. As was observed in the three transmission bus model, the total TSO+DSO solving time for the *Decentralised* model is higher

[48] TSO in the case of the *Centralised* model and both DSO and TSO in the *Local market and Decentralised market* models.

than the other two models due to time taken to produce the aggregated bid/offer curve for the Rame network. However, aggregating the Rame distribution system to a single aggregated bid/offer curve has resulted in a TSO solve time of less than half of the *Centralised* model*.* The TSO solve time is also lower in the *Local market* compared to the *Centralised* model because distribution system modelling is assigned to the DSO in the *Local market*, which reduces the TSO network model size by 33 buses in this example.

4.4.1.2 Local market

In the maximum generation snapshot for the *Local market* case*,* the DSO congestion market first runs to solve network constraints within the Rame network. Both the red and amber states of the *Local market* traffic light scheme (illustrated in Figure 3-4) are triggered due to requiring reductions to the set points and upper bounds of several of the DERs to bring the export power flow within the Rame ($\mathcal{N}$-1) BSP transformer reverse power flow limits. The adjusted positions are passed to the TSO balancing market with the DERs modelled as being at a single bus on the distribution side of the T-D interface. The TSO does not model distribution network constraints but does have access to individual DERs (within limits approved by the DSO). In the TSO optimisation there is no need for any further adjustments to DERs within Rame, beyond those taken by the DSO, as there are no binding transmission network constraints, and the grid balancing price is set to zero. The objective function cost for the DSO in the *Local market* reported in Table 4-13 is for congestion management of the Rame network (the cost of reducing DER set points in the red state), whereas the TSO objective function cost is for managing the transformer constraints at the other BSPs. If the distribution networks behind all the BSPs were operated by a DSO (or multiple DSOs) in the *Local market* DSO-TSO coordination model, then all congestion management costs would fall on the DSO(s) and the TSO objective function cost in this example would be zero.

In this example, the objective function cost of the *Local market* is approximately the same as the *Centralised* model (as shown in Table 4-13) within a margin of error relating to loss approximation which is explored in more detail in the next case study which has a non-zero grid cost. However, this very much depends on the costs to the DSO of adjusting the upper and lower bounds of DERs in the amber state of the traffic light scheme, which in this example has been assumed to be zero. The effect of including costs to the DSO for lower and upper bound adjustments in the amber state is now illustrated.

Amber state DSO costs: lower bound adjustment

In the maximum generation snapshot, the *Local market* objective function matches the optimal *Centralised* model solution, however, additional costs could be incurred by the DSO to ensure secure network operation.

In the above example, no cost was incurred for the DSO to increase DER lower bounds in the amber state of the DSO congestion market to prevent actions by the TSO causing demand shedding at distribution level. In practice, a DNO gives limited credit to intermittent DERs in meeting grouped demand in the event of an ($\mathcal{N}$-1) outage [173]. DNO's usually carry out network reinforcement when there is insufficient import capacity to meet maximum demand, however, in the move towards the DSO, markets are emerging to utilise DER flexibility as an alternative to network reinforcement. In this thesis, it is assumed that DERs can be utilised to ensure that maximum demand is met, however, it is recognised that network reinforcement could be a more cost effective alternative.

In Rame, the import transformer capacity is 91.6 MW (parallel flow limit for the 45MW and 60 MW transformers), whereas the maximum demand is 94.8 MW. Without any DER output in Rame or network reinforcement there is an import capacity shortfall of 4.9 MW (which includes 1.7 MW losses).

To guarantee uninterrupted supply within Rame, the DSO must increase the combined lower bounds of DERs within Rame to 4.9 MW. This is an extreme example where it is assumed that the DERs all have lower bounds set to zero, whereas many DERs could have lower bounds above zero for operational reasons, in which case the DSO may not need to adjust lower bounds to guarantee security of supply. Nonetheless, assuming lower bounds of zero, if the DSO pays the same amount to increase lower bounds as for an increase in output (i.e., the 'Cheap curtailment' offer prices from Table 4-12), increasing the lower bounds by 4.9 MW would come at a cost of £138 to the DSO.

The system costs and bidding behaviour of participants of the *Local market* model will very much depend on the price paid by the DSO for adjustment to DER lower bounds. If the DSO does pay for adjustment to DER lower bounds, it would be in the interest of DERs to always set lower bounds to zero so that they are paid for increases to the lower bound when required by the DSO. If the price of the DSO adjusting DER lower bounds is set to zero, there is no incentive for DERs to strategically set their lower bounds to increase their income which will lower DSO system balancing costs. However, it DERs are providing a service to the DSO, in guaranteeing security of supply, particularly where the alternative is network reinforcement, there is an argument for compensating DERs for guaranteeing their lower bounds. Rather than relying on the DSO market to reward DERs for adjustments to lower bounds, a separate capacity market style mechanism could be preferable, to prevent strategic bidding and ensure security of supply at lowest cost.

Amber state DSO costs: upper bound adjustment

In the above example, the DERs within Rame were all operating with their set points at their upper bounds. Due to export constraints in Rame, in the *Local market* the DSO reduced the set points and upper bounds of several DERs in the red and amber states of the traffic light scheme and it was assumed that the DSO paid the bid price to reduce set points in the red state. Therefore, the *Local market* arrived at approximately the same objective function as the *Centralised* model. However, if the set points are not at the upper bounds, in the *Local market* the DSO may be required to reduce the upper bounds, even if the set points remain unchanged.

This can be illustrated by re-running the *Centralised* and *Local market* optimisations with the set points of several DERs within Rame reduced below their upper bounds. For a 21.5 MW reduction in DER set points within Rame while keeping the upper bounds the same, the objective function for the *Centralised* model is £2262. This is a reduction of £112 from the original result, as the DER turn-down required by the TSO within Rame is reduced by 21.5 MW. In the *Centralised* model the TSO only pays for reductions to set points, and does not need to change DER upper or lower bounds.

In the *Local market,* the DSO is still required to reduce the upper bounds of the DERs despite the fact the set points are now reduced. Due to export constraints within Rame, the DERs cannot operate at their upper bounds, therefore the DSO has to reduce the DER upper bounds by 21.5 MW to prevent actions by the TSO causing distribution constraints. Assuming the DSO has to pay the bid price for changes to the upper bounds, the total system balancing cost is £2372, which is £110 higher than the *Centralised* result for a 21.5 MW reduction in DER set points.

In practice, it would be less likely that intermittent DERs, specifically PV and wind, would operate below their upper bounds, in which case this issue would not commonly arise. An exception to this would be if DERs were to provide an upward reserve capacity, in which case they may operate below their upper bounds to have headroom to increase output when called upon by the TSO. In this case, the DSO reducing the upper bounds of DERs would reduce their potential income in an upward reserve market and should therefore be compensated at their bid price. This situation can be replicated using a non-zero grid cost and will be explored in the following case study.

4.4.1.3 Decentralised model

In the *Decentralised model,* the DSO congestion market first solves distribution network constraints within Rame by reducing the output from several of the DERs and provides the TSO with the optimal T-D flow (from the DSOs perspective) and the aggregated bid/offer curve representing the costs of adjusting the T-D flow from the optimum. In the TSO optimisation, the DERs are modelled as being at a single bus on the distribution side of the T-D interface. As there are no transmission constraints in the Cornwall model, and with the grid balancing cost set at zero, the TSO does not adjust the T-D flow at Rame. The aggregated bid/offer curve with 2 points is sufficient to produce the same objective function as the *Centralised* model within a small margin of error (as shown in Table 4-13). A non-zero grid balancing cost case study is required to demonstrate the inaccuracy of the aggregated bid/offer curve (shown on the three bus model in section 4.2.1.3) in representing the cost of adjusting the D→T power flow and this is explored in the next case study.

4.4.2 Results: single DSO snapshot with non-zero grid cost

In the previous case study with zero grid cost, the TSO had no requirement to access DER flexibility and did not adjust the D→T flow set by the DSO. A major benefit of DSO-TSO coordination is in facilitating TSO access to DER flexibility. This is demonstrated in the following case study for the three coordination schemes in this thesis.

The inputs to this case study are identical to the above maximum generation snapshot with the inclusion of a non-zero grid balancing cost to represent the TSOs requirement for DER flexibility. The grid bus balancing cost (at INDQ41 in Figure 4-6) is set at £8/MWh, meaning it costs the TSO £8 for every MWh exported to the grid from the

DSO. This value has been chosen as it will be cheaper for the TSO to turn down firm and mixed generation from Table 4-12, as these DERs have bid costs below £8/MWh, rather than exporting their output to the grid. This represents the case of the TSO balancing market being 'long' meaning generation outstrips supply, in which case the TSO may be required to pay generators to decrease output and £8 is a proxy for the marginal price in the TSO market.

4.4.2.1 Summary of results: non-zero grid cost

The results of the ACOPF with system balancing for each of the three DSO-TSO coordination models is summarised in Table 4-14.

The objective function cost for the DSO in the *Local market* and *Decentralised* model reported in Table 4-14 is for congestion management of the Rame network, whereas the TSO objective function cost is for managing the transformer constraints at the other BSPs and for overall system balancing. If the distribution networks behind all the BSPs were operated by a DSO (or multiple DSOs) using the *Local market* DSO-TSO coordination model, then all distribution congestion management costs would fall on the DSO(s) and the TSO objective function cost would only be for system balancing and transmission congestion management.

Table 4-14: Maximum generation snapshot (non-zero grid cost) : objective function and solving time for DSO-TSO coordination models with single DSO.

	Centralised		**Decentralised**[1]		**Local Market**	
	Objective function cost[2] (£)	Solve time (s)	Objective function cost[2] (£)	Solve time (s)	Objective function cost[2] (£)	Solve time (s)
TSO	5280	4.1	4802.4	1.6	4698.1	2.5
DSO	-	-	570.9	18.7	570.9	6
Total	5280	4.1	5373.3	20.3	5269	8.5

[1]Results for aggregated bid/offer curve with 2 points.

[2]The objective function cost for the DSO is the congestion management cost for Rame, and the objective function cost for the TSO includes the congestion management cost for the remaining five BSPs plus the cost of overall system balancing.

In the TSO balancing market for all models, the TSO has access to the DERs in the RAME network and access to the aggregated DERs behind the other 5 BSPs. In the *Centralised* model, the TSO has a full T-D model whereas in the *Local market* and *Decentralised* models, DERs within the Rame network are prequalified in the DSO market to respect the Rame distribution network constraints. With the addition of a grid export cost of £8/MWh, In the TSO market all DERs with bid costs below £8/MWh have their output reduced[49], this includes all 'firm' generators which have a bid cost of £2/MWh and 'mixed' generation at £5/MWh. The total export from the Cornwall network in the *Centralised* model is decreased from 439 MW in the case of zero grid cost to 315 MW for non-zero grid cost. Renewable generation (wind and PV) has a bid cost of £10/MWh and is only curtailed due to BSP constraints (as in the zero grid cost example) rather than due the non-zero grid cost.

The solve times for the three models are similar to those in the zero grid cost example, however the objective function costs for the *Decentralised* and *Local market* models diverge from the optimal *Centralised* model. The reasons for this are an inherent loss estimation error in the *Local market* model and the aggregated bid/offer curve error in the *Decentralised* model which are explored in more detail below.

4.4.2.2 Local market: loss estimation error

In the *Local market*, the DSO firstly makes any necessary adjustments to respect distribution constraints as part of the traffic-light style DSO congestion market and passes the optimal D→T flow F_s to the TSO balancing market. The T-D interface flow, F_s, is determined in the DSO congestion market using ACOPF and includes any losses in the distribution system:

$$F_S = \sum_{g \in G} p_g^G - \sum_{d \in D} p_d^D + Losses \tag{4-4}$$

However, the losses are a function of the power flow and will therefore change as a result of any adjustment of F_S in the TSO balancing market. This loss estimation error is inherent in the *Local market* methodology, and a loss adjustment correction would be required to reduce (or remove) this error.

To illustrate the magnitude of the error, the losses and resulting objective function cost error are considered for the current non-zero grid cost example. The optimum D→T power flow F_S found in the DSO congestion market for Rame (corresponding to the *Local market* results in Table 4-14), is 73.1 MW which is the maximum export from

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49 If all DERs had bid costs above £8/MWh, then there would be no incentive for the TSO to reduce their output (aside from to manage BSP transformer constraints), as it would be cheaper to export their output (at £8/MWh) than to reduce it.

the two Rame transformers. The maximum export from DERs within Rame is 172.3 MW and demand is 94.8 MW, therefore by re-arranging (4-4), the losses are estimated as 4.4 MW for this specific power flow[50]. The losses are added to the aggregated distribution demand at the Rame T-D interface of the TSO balancing market model. Due to the grid export cost of £8/MWh, in the balancing market the TSO reduces the output of Rame DERs with bid costs under £8/MWh by 45 MW in total, and subsequently reduces the Rame D→T flow to 28.1 MW.

When the reduced DER output and losses are modelled on the Rame distribution system, the resulting losses are 3.6 MW which is a reduction of 0.8 MW (18%) from the first estimate. In this example, overestimating the losses results in underestimating the balancing cost to the TSO and DSO, as higher losses mean lower adjustment in DER output or lower payments for grid export, hence the underestimate of overall objective function by £11 (0.2%) compared to the optimal *Centralised* model result. The error margin seen by the DSO would be higher: a loss estimation error of 0.8 MW equates to around 2.8% of the 28.1 MW Rame D→T flow determined in the TSO optimisation. In the absence of a loss function, either the TSO or DSO would be required to pay for the required adjustment in D→T flow, either by adjusting grid import or DER set points, as a result of the loss estimation error.

4.4.2.3 Decentralised model: aggregated bid/offer curve error

It was first found in the three transmission bus case study (section 4.2.1.3) that using an aggregated bid/offer curve with a limited number of evenly distributed points provides an imperfect representation of the cost of adjusting the D→T power flow in the *Decentralised* model. It was shown that this can result in a suboptimal objective function cost due to the TSO setting a suboptimal D→T power flow in the balancing market based the imperfect aggregated bid/offer curve. In this thesis, the difference in objective function cost for the TSO between the optimal *Centralised* model, and that of the aggregated bid/offer curve in the *Decentralised* model, is referred to as the 'aggregated bid/offer curve error'. Increasing the number of points on the aggregated bid/offer curve was shown in section 4.2.1.3 to reduce the aggregated bid/offer curve

[50] This figure is confirmed as matching the sum of the distribution branch and transformer losses returned by ACOPF.

error, however, this comes at the expensive of increased computational time to compute the objective function cost at each point.

The aggregated bid/offer curve error is highlighted by increasing the number of points, z, in the aggregated bid/offer curve estimation: the results shown for z= 2,3 and 4 are presented in Table 4-15. The objective function error compared to the optimal *Centralised* model result (£5280) is 1.8% for z=2 and 0.13% for z=4, with a corresponding increase in computation time of 28% or 5.6 seconds.

Table 4-15: Decentralised model: Computation times and objective function with number of PWL points, z.

	Time (s)				**Objective function cost (£)**[1]			**Objective function Error (%)**[2]
z	**DSO PWL**	**TSO**	**DSO redispatch**	**Total**	**DSO**	**TSO**	**Total**	
2	16.4	1.6	2.3	20.3	570.9	4802.4	5373.3	1.8
3	19.2	1.8	2.2	23.2	570.9	4737.1	5308	0.53
4	22.2	1.8	1.9	25.9	570.9	4715.9	5286.9	0.13

[1]The objective function cost for the DSO is the congestion management cost for Rame, and the objective function cost for the TSO includes the congestion management cost for the remaining five BSPs plus the cost of overall system balancing.

[2]Relative to the *Centralised* model result (£5280)

Figure 4-7 shows the marginal cost of reducing the Rame D→T flow from the optimal value F_S (73.1 MW) for aggregated bid/offer curves with z=2,3 and 4 points. As a reminder, F_S is the D→T flow corresponding to the minimum cost of DER adjustments to solve distribution congestion in the DSO market. In this example, the DSO reduced the output of several DERs to manage Rame distribution network congestion. The resulting D→T flow F_S from the DSO market, 73.1 MW, is the reverse power flow limit for the two Rame transformers. It is worth noting that the DSO has priority access to the cheapest DERs to resolve distribution congestion in the DSO market, and the DERs represented in Figure 4-7 are those with remaining downward flexibility available in the TSO market.

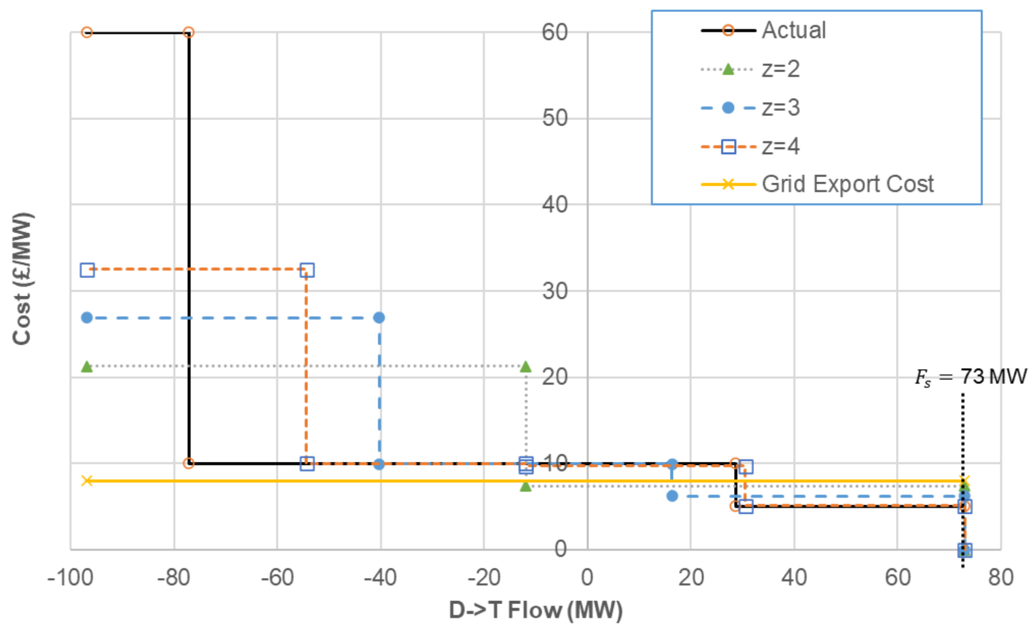

Figure 4-7: Decentralised model: marginal cost derived from aggregated bid/offer curves with 2, 3 and 4 points (z=2,3 and 4) and 'Actual' flexible demand bid curve.

The revised D→T flow F_R determined by the TSO during system balancing depends on the intersection between the marginal TSO export cost (£8/MW), and the marginal costs for adjusting the D→T flow in Figure 4-7. For z=2, F_R occurs at -12 MW, for z=4 it occurs at 30.5 MW, whereas the optimal F_R (as determined in the *Centralised* model), is at 28.6 MW. With increasing points z, the TSO has a closer representation of the cost of adjustments to the D→T flow from the optimal value F_S, however, this comes at the expense of a 28% increase in computational time, from z=2 to z=4. In this example, the 34 DERs within Rame were grouped into bids of £5/MW, £10/MW and £60/MW which resulted in three steps in the merit order. For a larger number of DERs with more variation in bid/offer costs, the number of points in the aggregated bid/offer curve required to provide a reasonable representation would increase and the computational time could run into several minutes for a large distribution network.

4.4.3 Model selection for further development

After consideration of the higher computation times and aggregated bid/offer curve error, the *Decentralised* model has not been modelled further in this thesis. For the *Decentralised* model to be applied successfully, a method of minimising the aggregated bid/offer curve error, such as smart selection of points, could be developed which is outside the scope of this thesis and represents an area for further work.

A further reason for not selecting the *Decentralised* model is that it involves the DSO market carrying out final DER dispatch after the TSO market. This introduces a risk that actions by the DSO could contravene the TSOs requirements for stable system operation. In the *Local market*, the TSO carries out final dispatch of DERs which aligns more closely with existing GB balancing market operation and reduces the risk of actions by the DSO contravening the requirements of the TSO. The *Local market* has also been shown to be a more tractable solution with the error limited to the estimation of losses. Therefore, the *Local market* shall be applied in the remaining DSO-TSO coordination case studies in this thesis and benchmarked against the *Centralised* model.

4.5 Local market case studies

To assess the scalability of the *Local market* and the competition between DSO and TSO for DER flexibility, the following case studies are carried out by applying the *Local market* on the Cornwall network (introduced in section 4.3):

- a snapshot study of the computational time for multiple DSOs in comparison to the *Centralised* model.
- a snapshot study of increasing distribution network size to illustrate how computational time scales with network size.
- a timeseries analysis with varying grid balancing cost with a single DSO.

The results and discussion of these case studies is presented in the remainder of this section.

4.5.1 Results: multiple DSOs snapshot with non-zero grid cost

To compare the performance of the *Centralised* and *Local market* models, the number of DSOs[51] is increased by replicating the Rame 33 kV network at three BSPs in the Cornwall network: Camborne, Fraddon and Hayle. To allow comparison of objective

[51] For simplicity it is assumed that each T-D interface is operated by a different DSO. However, in practise, a single DNO region in GB has many T-D interfaces which could be operated by a single DSO.

function and grid export; the total demand, total generation, and generation mix (PV, wind, firm) in each DSO network matches that of the respective BSPs given in Table 4-9, Table 4-10 and Table 4-11. Given that the same 33 kV network is being used in each DSO region, the intention is not to accurately model distribution network constraints in Camborne, Fraddon and Hayle, but to consider how the computational times vary with increasing numbers of distribution network regions managed by separate DSOs in the *Local market* model. These times can be compared with the equivalent *Centralised* model which optimises all DSO networks within a single network model. Computation times are given in Table 4-16 for *Centralised* and *Local market* balancing market dispatch for the maximum generation snapshot with increasing number of DSOs from one to four.

Table 4-16 Computation time, objective function and grid export with number of DSOs.

		Computation time (s)				**Objective Function (£)**		**Cornwall Grid Export (MW)**	
N	Buses	Local Market			Centralised	Local Market	Centralised	Local Market	Centralised
		DSO*	**TSO**	**Total**					
1	60	6	2.5	8.5	4.1	5269	5280	313.7	315
2	93	5.3	2.5	7.8	6.6	5264	5270	312.9	313.9
3	126	5.2	3.7	8.9	11.5	5241	5251	312.9	313.0
4	159	5.2	4.4	9.6	16.6	5240	5249	312.6	312.7

* DSO times are the average per DSO as this operation would be done in parallel.

For each increase in the number of DSOs, N, the number of buses increases by 33 and the number of demands and DERs increase by 11 and 21, respectively. This increases the problem size for the *Centralised* model and results in the computational time increasing by a factor of 4 as the number of DSOs increases. At three DSOs, the *Local market* model becomes faster than the *Centralised* model due to the ability to parallelise the DSO network modelling. In the *Local market,* the TSO time increases with increasing N due to the number of DERs increasing, however the number of buses remains the same as the DSO networks are not modelled by the TSO which is a major advantage of the *Local market* model. The *Local market* being faster than the *Centralised* model for 126 buses and upwards indicates that for networks with thousands of buses, the *Local market* model will perform significantly better than the

Centralised model in terms of computational times, if sufficient numbers of network regions are able to be managed in parallel.

The objective functions of the *Centralised* and *Local market* in Table 4-16 are within 0.2% for all tested cases. The total Cornwall export decreases with increasing N in both the *Centralised* and *Local market* models due to the inclusion of network losses for each additional DSO network. The *Local market* loss estimation error is largest for N=1 resulting in the largest difference in grid export between the *Local market and Centralised* models. The reason for the loss estimation error being largest for N=1 is that the Rame network has the largest difference between the optimal DSO D→T power flow and that determined by the TSO optimisation. The larger the TSO redispatch of DERs within a distribution network for a given DSO, the larger the loss estimation error in the *Local market*.

4.5.2 Results: run-time for increasing size distribution network

Due to the potential for tens of thousands of nodes (and upwards) in a distribution market model, with similar numbers of DERs, the tractability of the *Local market* model is assessed for larger distribution networks. Different solvers are also compared to assess the robustness of the non-linear programming (NLP) solver ipopt [166] in producing accurate results of the objective function (4-5) compared to other available NLP solvers.

$$\min \sum_{g \in G} \left(C_g^{\downarrow} p_g^{\downarrow} + C_g^{\uparrow} p_g^{\uparrow} \right) + \sum_{d \in D} V_d^D \left(P_d^D - p_d^D \right) \tag{4-5}$$

The distribution model has been extended to illustrate the tractability of the proposed solution for a larger number of nodes. Table 4-17 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 BSPs shown in Figure 4-6. The 1001 node network was produced by adding an 11 kV distribution feeder[52] replicated at several secondary substations across the 33 kV network.

[52] The 11 kV feeder is a 46 bus section of the 247 bus Whitchurch network, produced during the *Flexible Networks* trial [213].

Table 4-17 - Computation time for increased distribution network size.

Number of nodes	Number of DERs	Time for DSO (s)	Time for TSO (s)
60	62	6.8	1.1
258	225	28	2.2
1001	790	150	5.3

The 258 node network is representative of the size of the region's 33 kV networks, 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 [174], could 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 and approaches 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.

Robustness of the solution

The ACOPF formulation, (3-3)-(3-14), which is applied in the *Local market*, is non-linear and the NLP technique employed does not guarantee a global optimum solution. To assess the accuracy of the non-linear solver employed for ACOPF in this thesis (ipopt), results of the objective function (4-5) for a single snapshot, are compared using a range of NLP solvers, for the 60, 258 and 1001 node networks in Table 4-18. 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 4-18: DSO balancing objective function (4-5) with selected non-linear programming solvers.

	Objective Function (£)		
Solver	**60 Node**	**258 Node**	**1001 Node**
Ipopt [166]	332.6	3575.85	6050.31
Knitro [175]	332.99	3581.87	6066.18
Conopt [176]	332.98	3596.88	6061.52
filterSQP [177]	332.98	3589.79	6064.21
SNOPT [178]	332.98	3628.83	6123.85

4.5.3 Results: timeseries with varying grid balancing cost

To provide an indication of how DSO and TSO objectives will align for different grid balancing costs and different levels of import/export from the distribution system, the allocation of flexibility between the DSO and TSO in the *Local market* is studied over multiple timesteps. Timeseries analysis of DSO and TSO dispatch is carried out with varying grid balancing cost as well as varying output from renewable generation and demand. The following timeseries scenarios are analysed on the Cornwall network (Figure 4-6) for a single DSO in the Rame network, using the *Local market* model for a 24 hour period (with 48 half hour periods):

- Maximum import to distribution: Maximum demand and minimum output from intermittent generation (winter day).
- Maximum export from distribution: Minimum demand and maximum output from intermittent generation (summer day).
- Negative transmission imbalance price: Reflecting surplus of generation over demand in wider transmission system.

Each scenario is executed using both the 'Cheap Curtailment' and 'Cheap DSR' DER price cases as outlined in Table 4-12. The demand and generation capacities are the 2030 Community Renewables scenario shown in Table 4-9 and Table 4-10 respectively. Demand profiles are based on measured BSP flows from [179] for the year 2017 for an area with minimal embedded generation. Projected deployment of EVs and HPs under the 2030 CR scenario, were added to the baseline BSP demand profile, to create the 2030 demand profiles. Generation profiles for PV and wind are from the Renewables Ninja [180] resource using 2016 data.

Grid balancing cost

The grid import/export cost is represented by the 2018 GB imbalance price (C_{IMB}) from [179]. The imbalance price is the cost to the TSO of correcting system imbalance between supply and demand and does not include TSO balancing actions due to network constraints.

The system imbalance price is used in this thesis to show the value of DER flexibility for a range of balancing prices, although the accepted DER actions could be part of the imbalance price calculation. Some expected market outcomes are outlined below;

- At times of high imbalance price C^{IMB}, DERs will be turned up.

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. 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.

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. Highly negative prices represent periods when the market is ‘long’, and the TSO will pay to increase power flow to distribution (or reduce export power flow from D→T).

Selected results

Results are presented for the following cases:

- ‘Cheap curtailment’: maximum import, and negative imbalance price.
- ‘Cheap DSR’: maximum import and maximum export.

The intention of these cases is to provide insights into allocation of flexibility between the DSO and TSO in the *Local market*.

4.5.3.1 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.

Maximum Import

In the *Local market* model, demand must be met with all DERs set to their lower bounds, to achieve the 'green' state. The DSO may increase the lower bounds on generation in the 'amber state' to guarantee peak demand is met, or use DSR and batteries to reduce the peak demand.

The maximum import case (see Figure 4-8), which occurred on a winter's 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. The imbalance price, shown in the bottom plot in Figure 4-8 is below £50/MWh for most of the time, however there are some price spikes over £100/MWh at ~07:00 and at ~18:00.

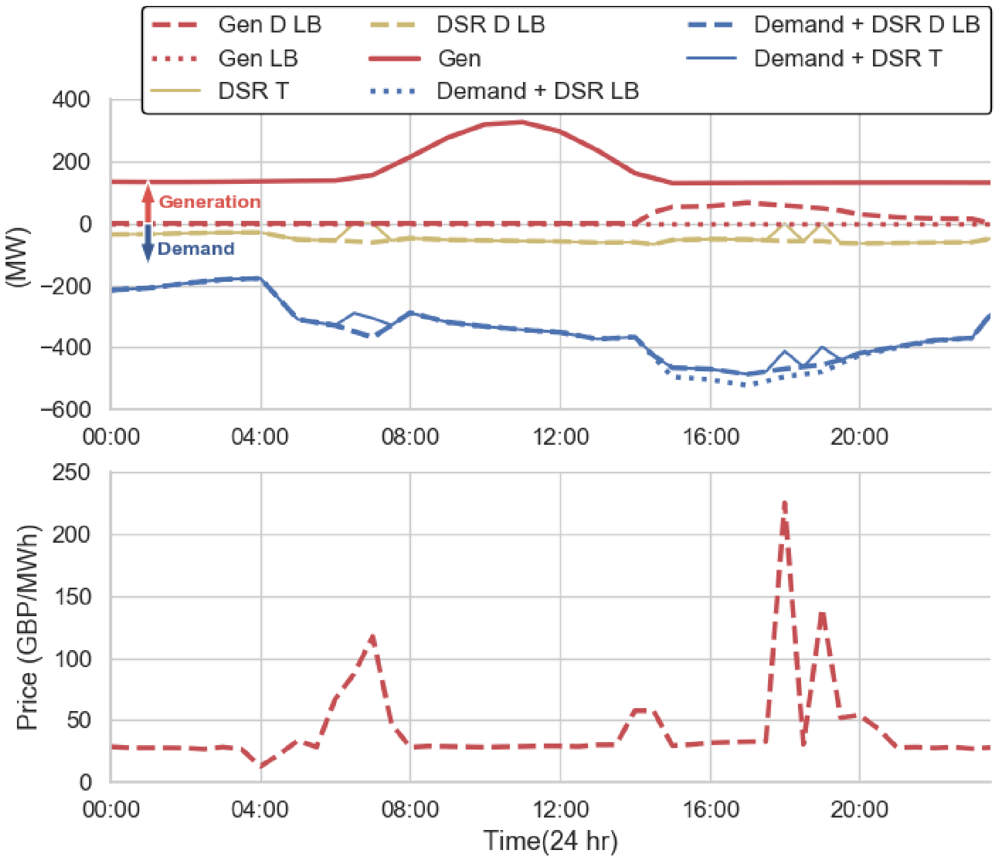

*Figure 4-8: **Top Plot:** Dispatch by DSO and TSO for 'Cheap Curtailment' for 24 hour period of Maximum Import (in January). D and T are used to indicate results of the DSO and TSO markets, respectively. Dotted lines are unmodified positions. UB - Upper Bound, LB - Lower Bound. **Bottom Plot:** Transmission Imbalance Price.*

At 14:30, the ‘amber' state (in the 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 instructs generators to increase their lower bounds (see increase in ‘Gen D LB' in Figure 4-8). 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 and embedded generation 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. If the DSO had prevented upward DSR due to export constraint, this would be contrary to the TSOs' objectives.

Truro is the most demand constrained region in Cornwall (see Table 4-9) for the 2030 CR scenario. In Truro, during the 5 peak demand hours of the maximum import scenario (see Figure 4-9), 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 at around 17:30. The DSO market would quickly highlight the need for flexibility in this region as a high price would be paid to prevent load shedding. Some upward DSR flexibility within Truro was available to the TSO to respond to the imbalance price spike at ~07:00, however next to none was available for the evening price spikes as all available upward DSR was committed by the DSO.

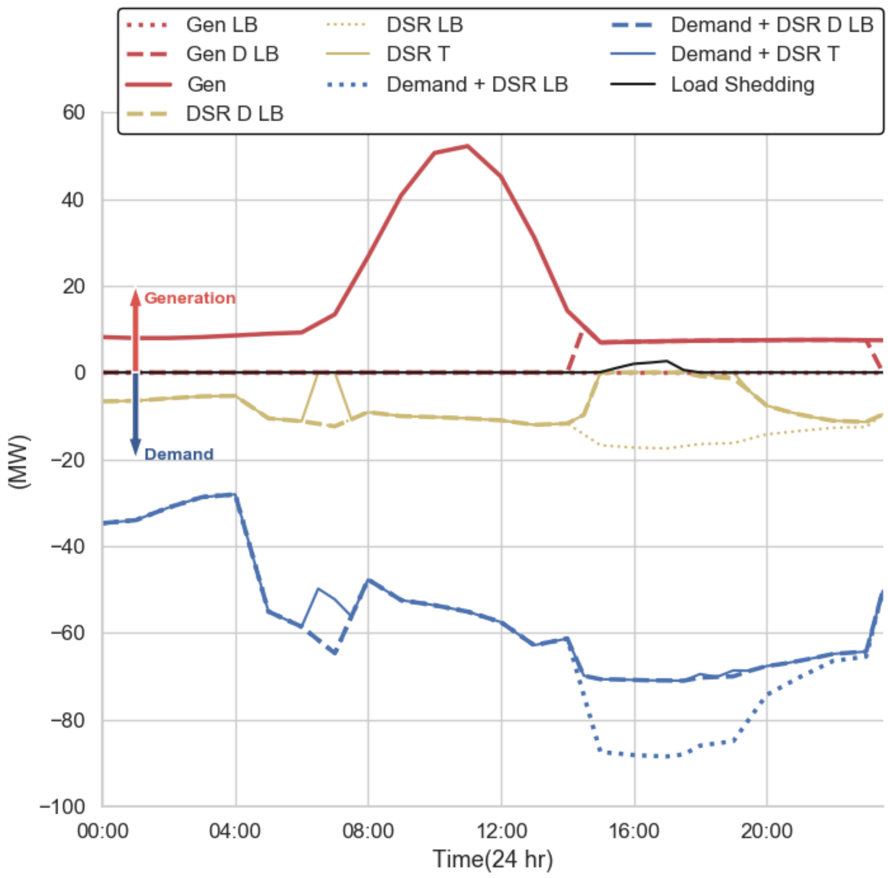

Figure 4-9: Dispatch by DSO and TSO for 'Cheap Curtailment' in Truro BSP for 24 hour period of Maximum Import. D and T are used to indicate results of the DSO and TSO markets, respectively. Dotted lines are unmodified positions. UB - Upper Bound, LB - Lower Bound.

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. For example, 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 [179]. Negative prices are included in the work of this thesis 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 [181]. The negative imbalance price period in March 2019 has been modelled with the dispatch from the maximum export scenario where high renewable output results in a requirement for curtailment as shown in Figure 4-10.

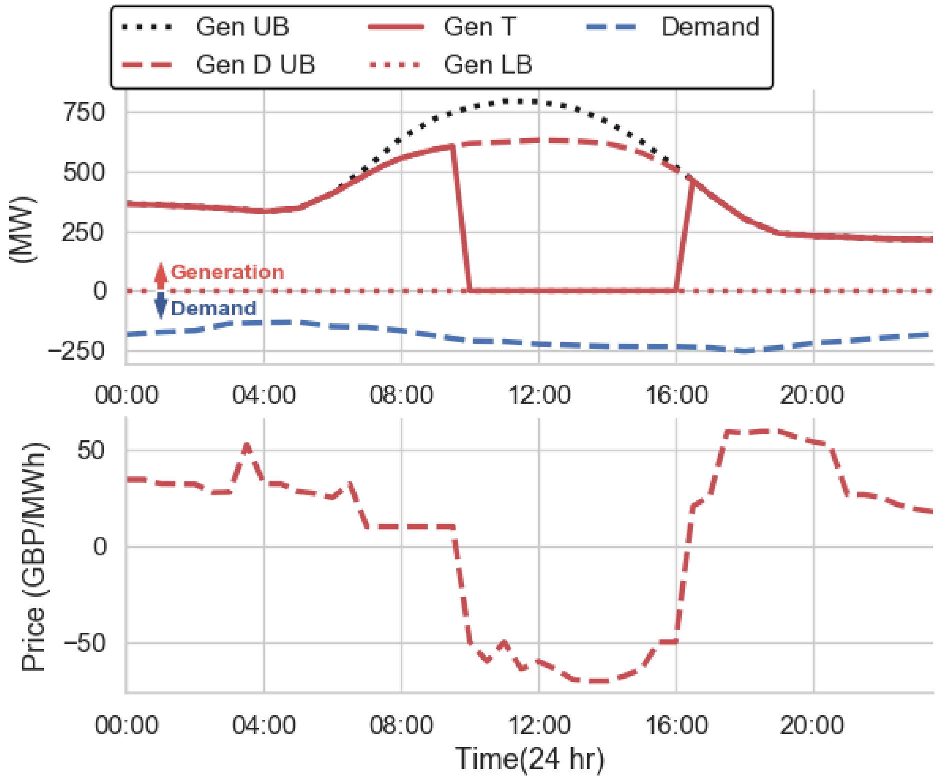

*Figure 4-10: **Top Plot:** Dispatch by DSO and TSO for 'Cheap Curtailment' for 24 hour period with negative imbalance price. D and T are used to indicate results of the DSO and TSO markets, respectively. Dotted lines are unmodified positions. UB - Upper Bound, LB - Lower Bound. **Bottom Plot:** Transmission Imbalance Price.*

At around 06:00 the DSO enters the 'amber' and 'red' states due to the upper bounds and set points 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 the DERs (after DSO market clearing), is used by the TSO in response to the negative imbalance price. 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 reduced system balancing costs by accessing lower cost flexibility from DERs compared to exporting at the imbalance price.

4.5.3.2 Cheap DSR

In the ‘Cheap DSR' case the cost of utilising DSR in the DSO balancing market is lower than that of generation or energy storage. 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 to reduce system balancing costs by reducing system export at the imbalance price.

Maximum Import

The results of the maximum import scenario for the ‘Cheap DSR’ case are shown in Figure 4-11 and are very similar to the ‘Cheap Curtailment' case (see Figure 4-8). The only difference is the volume of DSR used by the TSO, due to the offer price being £30/MWh in ‘Cheap DSR' and £70/MWh for ‘Cheap Curtailment'. In the ‘Cheap DSR’ case, the TSO can reduce system balancing costs any time the transmission price goes above £30/MWh by reducing demand and subsequent transmission import. The TSO’s savings in system balancing costs equates to the difference between the transmission price and the DSR offer price.

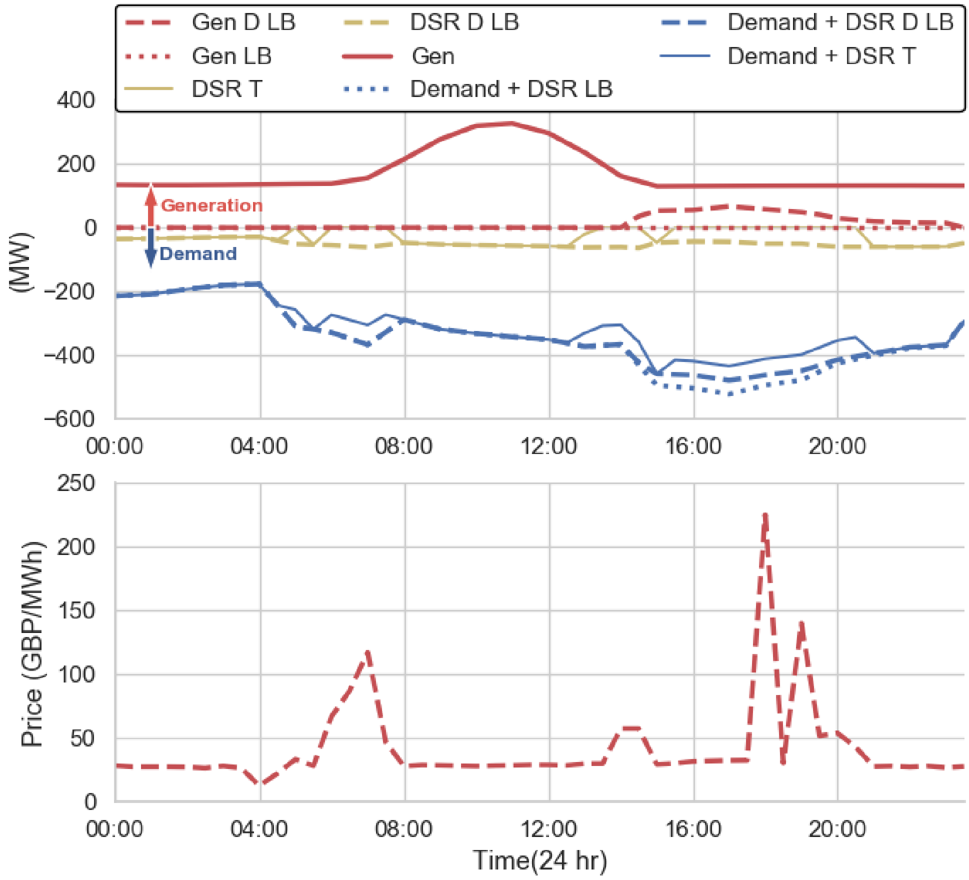

*Figure 4-11: **Top Plot:** Dispatch by DSO and TSO for 'Cheap DSR' for 24 hour period of Maximum Import (January). D and T are used to indicate results of the DSO and TSO markets, respectively. Dotted lines are unmodified positions. UB - Upper Bound, LB - Lower Bound. **Bottom Plot:** Transmission Imbalance Price.*

The DSO market entered the amber state and 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 the 'Cheap DSR' or 'Cheap Curtailment' cases. As discussed in section 4.4.2, increasing DER lower bounds could be paid for by the DSO due to the DERs contributing to security of supply. The DSR is operating at its lower bounds (representing maximum demand), therefore increasing DSR lower bounds involves increasing the set points (in the red state of the DSO market) which comes at an offer cost of £30/MWh.

Maximum Export

The results of the maximum export scenario are shown in Figure 4-12, where, at 06:00 the DSO market red state is activated, due to the generator upper bounds and set points breaching ($\mathcal{N}$-1) secure transformer reverse capacity limits. DSR and generator[53] 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 in the red state, whereas the DSR is operating below its upper bound, and only has to reduce the upper bound (not its output).

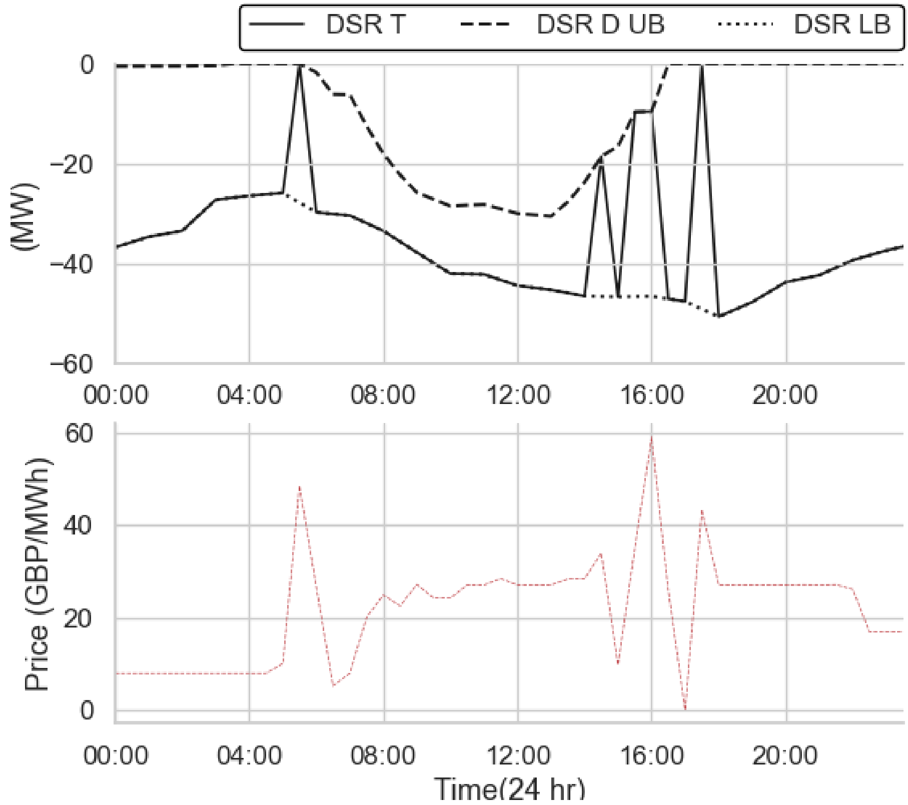

*Figure 4-12: **Top Plot:** Dispatch by DSO and TSO for 'Cheap DSR' for 24 hour period of Maximum Export (August).D and T are used to indicate results of the DSO and TSO markets, respectively. Dotted line is unmodified position. UB - Upper Bound, LB - Lower Bound. **Bottom Plot:** Transmission Imbalance Price.*

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,

[53] Generator dispatch is not shown in Figure 4-12 to focus on DSR actions.

17:30). In this example, the *Local market* allowed the DSO to use the most economic source of flexibility to manage distribution constraints and the remaining higher priced flexibility was available for the TSO to increase system export at times of high imbalance price, but by a reduced upper limit set by the DSO in the local market. This is an example of DSO and TSO objectives not aligning, with the DSO limiting the provision of DSR to the TSO due to export constraints.

4.6 Local market coordination with ancillary services

As well providing flexibility to the DSO and TSO in the *Local market*, DERs may also have ancillary service contracts such as those for frequency response (e.g., FFR) or for providing reserve (e.g., STOR) with the TSO. On this basis, DERs or balancing units must inform the *Local market* operator of any STOR or FFR contracts with the TSO over any given settlement periods. This can simply be done by adjusting their upper or lower bounds provided to the DSO to include the required headroom to provide ancillary services contracted to the TSO. For example, if a 10 MW battery operator has a 3 MW STOR contract for availability between 4pm to 8pm on a given weekday, in the *Local market,* the operator of the battery must include 3 MW of headroom in their positions provided to the DSO for settlement periods between 4pm to 8pm. The upper bound provided to the DSO in the *Local market* would be 7 MW to ensure a further 3 MW is available to the TSO[54] even if the DSO chose to increase their output to the upper bound of 7 MW.

The cost to the *Local market* operator for reducing the availability of any DER to provide ancillary services to the TSO would likely be very high. This is because operators of DERs with ancillary service contracts would submit bids and offers calculated to offset the costs of interrupting their ancillary service obligations. This would reflect the potential lost income to the DERs if unable to provide ancillary services to the TSO and would encourage the *Local market* operator to find other cheaper sources of flexibility, such as flexible assets without ancillary service contracts, if necessary.

[54] The STOR could be activated by the TSO in the *Local market,* in the same way that STOR is activated in the GB balancing mechanism. In the *Local market*, the upper bound provided to the DSO would be 7 MW while the upper bound provided to the TSO would be 10 MW.

4.7 Discussion of findings

The performance of the *Local market, Centralised,* and *Decentralised* DSO-TSO coordination models have been assessed in terms of computation time and objective function cost. The accuracy of the *Decentralised* model improves with increasing points on the DSO bid curve at the expense of increased computation. In the larger 60 bus Cornwall network, with a single DSO, both the *Decentralised* and *Local market* models had balancing costs close to the optimal *Centralised* model with zero grid cost.

With a non-zero grid cost applied to the Cornwall network, the *Local market* and *Decentralised* deviated from the optimal result due to a loss approximation error in the *Local market* and the DSO aggregated bid/offer curve error in the *Decentralised* model. The *Decentralised* model has the advantage of pricing losses into the bid curve and the DSO carrying out final dispatch of DERs to cover distribution system losses. However, the *Local market* was seen to have significantly lower computation times and produce more accurate results than the *Decentralised* model. Furthermore, the DSO carrying out final dispatch of DERs in the *Decentralised* model presents a risk to maintaining system frequency as actions by the DSO could contravene system balancing requirements by the TSO. The pros and cons of the three models are summarised in Table 4-19.

Table 4-19: DSO-TSO coordination models pros and cons

Model	Pros	Cons
Centralised	• Single market clearing process. • Most accurate optimisation of resources. • Most suitable for unconstrained distribution networks (with no requirement for detailed distribution network modelling)	• Significantly extends operational scope of the TSO to include operating distribution system. • Increased computational time compared to multiple parallel DSO optimisations with increasing network size.
Decentralised	• Accuracy of method can be tuned by modifying the number of points on bid/offer curves. • Price of losses included in bid/offer curve.	• Aggregated bid/offer curve error gives suboptimal allocation of resources. • Most computationally expensive. • Final dispatch by DSO risks system stability.
Local market	• Parallelization of multiple DSO markets reduces computation times. • Simple methodology with TSO carrying out final dispatch of DERs after DSO clearing. • Clear priority of access to DERs between DSO and TSO (DSO taking priority).	• Loss approximation error can result in suboptimal allocation of resources. • System costs could be increased depending on the DSO market rules (e.g., whether to provide payments for adjusting upper and lower bounds).

The *Local market* approach was demonstrated for multiple DSOs operating distribution networks with 33 buses each. Beyond 3 DSOs, the *Local market* had lower computational times than the equivalent *Centralised* model, due to the DSOs being operated in parallel. For larger distribution networks, with up to 1001 nodes, computational times of up to 2.5 minutes were observed. This indicates that for distribution networks with tens to hundreds of thousands of nodes, more tractable formulations than the ACOPF applied in this thesis, such as linearised ACOPF or dual decomposition, could be required.

In the timeseries analysis on the Cornwall network using the *Local market,* the DSO and TSO both accessed flexibility from the DERs and in most cases the needs of the DSO and TSO aligned. At times of maximum import, the DSO ensured sufficient generation to meet maximum demand by increasing lower bounds of generation and DERs and upward flexibility was available for the TSO to respond to grid price spikes. In the case of maximum export, the DSO required downward dispatch of generation and reduction of the upper bounds of DERs. This reduced the flexibility available to the TSO to respond to imbalance price spikes, however there was significant upward flexibility remaining to the TSO while respecting distribution network constraints.

The allocation of costs for dispatch of DERs between the DSO and TSO is an important challenge in market design and it is critical to create the right price signals to incentivise efficient behaviour and investment [159]. In the coordination models applied in this thesis, the DSO pays for any DER output adjustments for distribution congestion management, but can adjust the flow across the D→T interface at zero cost. The DSO congestion management cost provides a strong price signal at the point of constraint, and although the TSO balancing costs could also be affected by the distribution constraint, the TSO can minimise these costs by accessing the cheapest source of flexibility available from multiple DSOs. Certain aspects of market design and behaviour have been simplified in this thesis and require further development in future work. For example, it was assumed that the DSO pays for adjustments to DER set points but not any adjustments to the lower or upper bounds, and the TSO only acted based the imbalance price. Furthermore, it has been assumed that the DERs give the same bids and offers to the DSO and TSO for adjustments. In practice, careful consideration would need to be given to the market rules. Firstly, the DSO would not always have to pay DERs for adjustments, particularly those granted non-firm connections, and it may be that they would preferentially enter markets where they could be rewarded by the TSO. In the *Local market* model, system costs can be increased by decoupling the distribution and transmission systems, however, this very much depends on the market pricing model used by the DSO and whether DERs would be paid for adjusting lower and upper bounds without adjusting their set points. This would be a matter for the regulator as it would impact customer costs (system balancing costs are passed on to them) and returns for DERs if their flexibility is being limited by the DSO.

In the Cornwall network, the prevalent distribution constraints are the BSP transformer reverse power flows, and in the *Local market* model these are included in both the DSO and TSO system balancing optimisations. If the BSP transformers were known to be the only distribution constraint, the TSO could include the BSP constraints in the transmission system balancing and other distribution constraints could be ignored. This removes the need for DSO-TSO coordination (or at least dramatically simplifies it), and in the *Local market,* payments for upper and lower bound adjustments by the DSO would no longer be required. For many less constrained networks, the prequalification recommended in the SmartNet *Centralised Market* model[55] could be adequate for managing distribution constraints, particularly if it identified constraint points that can be incorporated into the TSO optimisation, removing the need for full distribution network modelling. However, this approach would not be adequate when high DER penetrations could cause other thermal and voltage constraints within the distribution system rather than a single 'pinch-point'.

The *Local market* DSO-TSO coordination mechanism has the potential to operate alongside existing ancillary service markets. Through the provision of upper and lower bounds to the *Local market,* along with bids/offers for any changes to operating points, DERs can reserve the required flexibility to fulfil ancillary service contracts while providing any remaining flexibility to the DSO or TSO.

4.8 Chapter summary

This chapter contains case studies to assess the performance of the *Local market, Centralised,* and *Decentralised* DSO-TSO coordination models in terms of

[55] This is not to be confused with the *Centralised* model referred to from chapter 3 onwards in this thesis which corresponds to the SmartNet *Common DSO-TSO Centralised Model*.

computation time, objective function cost and, in the case of the *Local market,* in terms of allocating flexibility between the DSO and TSO.

The *Local market* has been found to provide a more efficient solution for DSO-TSO coordination than the *Decentralised* model in terms of lower computation time, greater accuracy of objective function cost and improved compatibility with existing GB balancing market arrangements. It has been shown that access to DERs can be shared between the DSO and TSO in the *Local market*, however, the DSO has priority access to the cheapest DERs which can under certain conditions limit access to DER flexibility for the TSO.

The DSO-TSO coordination models in this thesis have been developed for MV-HV distribution system congestion management. With the electrification of heat and transport, new methods for LV congestion management, and the aggregation of flexibility at LV will be required. In the next chapter, a LV congestion management scheme is developed to utilise flexibility from domestic EV charging, which is then integrated with the *Local market* in chapter 7.

Chapter 5:

LV Congestion Management Methodology

This chapter outlines a three-phase LV distribution network congestion management scheme (CMS) designed to be tractable and compatible with the DSO-TSO coordination mechanisms described in chapter 3.

The DSO-TSO coordination mechanisms developed in this thesis manage MV/HV distribution network congestion and provide a useful mechanism for coordinating access between the DSO and TSO to DERs located at, or aggregated to, MV/HV. However, they are not adequate for modelling LV networks as they assume balanced phases whereas three-phase unbalanced approaches are required for LV network modelling [137]. Three-phase (unbalanced) OPF approaches to LV network congestion management have been established in the literature [59], [143], [182], however their tractability is limited by the computational power and time required to solve non-linear AC OPF formulations on large networks. Furthermore, the application of three-phase OPF conventionally relies on a centralised market where the network constraints are known to the market operator. In practise, it may be beneficial to separate the network modelling activity, carried out by the DNO, and market optimisation activity, carried out by an aggregator. Such an approach is presented in [183], where the congestion management problem is separated into a two stage optimisation: firstly a power 'margin' calculation is carried out by the DNO; and secondly the EV and HP flexibility optimisation is carried out by the aggregator. In the LV CMS developed in this thesis, a similar approach is used in separating the network modelling and EV flexibility optimisation activities, but the first optimisation stage in [183] is replaced with a heuristic zonal headroom calculation to represent 3-phase network constraints. This allows the aggregator optimisation to be parallelised by zone (a set of customers on a section of electrical network) which can significantly improve tractability compared to a 3-phase OPF method.

In this chapter, a three-phase LV CMS is developed which can be operated in tandem with the *Local market* DSO-TSO coordination scheme[56]. As part of the LV CMS, a heuristic is developed for three-phase LV network congestion management which estimates network headroom based on both thermal and voltage limits. Novel aspects of the proposed methodology are that the network headroom calculation is separated from EV charging optimisation which is decentralised across LV network 'zones'. These zones, defined as the combination of feeder and phase to which customers are connected, allow congestion management to be separated into multiple sub-problems which lend themselves to parallelisation thus offering improved solution speed over centralised approaches such as three-phase OPF.

The electrification of heat and transport will increase the peak loading of LV networks [27], and domestic EV charging can cause LV network congestion if not coordinated. For example, in the My Electric Avenue EV charging trial (2013-2015) [52], it was found through the monitoring of charging events of 215 Nissan Leaf EVs (24 kWh) that for uncoordinated 'dumb' charging the After Diversity Maximum Demand (ADMD) could be increased from the currently used ADMD of 1 kW, up to 2 kW and that 32% of LV feeders across GB will require reinforcement if 40-70% of customers have 3.5 kW chargers. Although dumb charging of EVs can result in network congestion, coordinated or 'smart' charging of EVs and vehicle to grid (V2G) can provide a valuable source of flexibility to the DSO and TSO [184]. In the literature, EV optimisation strategies to reduce cost and emissions have been proposed [43] where it was found that 70% EV penetration could be accommodated with no voltage violations if the fleet were evenly balanced among phases. The addition of vehicle to V2G to EV optimisation was studied in [185] where it was shown to provide cost and emissions reductions and a 2019 public study on V2G found that V2G charging could generate significant revenues to EV owners if located in a distribution network congestion management zone [186]. While the benefits of EV optimisation have been demonstrated using case studies in the literature, there is a need for further work in developing scalable tools to maximise the benefit of EV flexibility and V2G, both to manage LV network congestion and provide grid services to the DSO and TSO.

[56] The LV CMS could also be integrated with the *Centralised* or *Decentralised* coordination schemes; however, for reasons outlined in section 4.4.3 the *Local market* has been selected as the preferred choice of DSO-TSO coordination scheme in this thesis.

The LV CMS proposed in this thesis utilises EV flexibility for LV congestion management and can be integrated with the *Local market* to provide grid services at higher voltages. The outline of this chapter is as follows: the high-level market operation is firstly outlined; the detailed LV CMS methodology is then described including the estimation of available network headroom; the formulation of an aggregator optimisation strategy is developed for EV charging using the available headroom; and finally, the methodology for validating the LV CMS is presented.

5.1 High-level market operation

In this thesis, a LV CMS is developed, which operates in advance of gate closure of the DSO congestion market (see Figure 3-1) in the *Local market* DSO-TSO coordination scheme. The purpose of the CMS is to manage LV network congestion, using network headroom[57] and footroom[58] as a proxy for power flow limits to prevent thermal or voltage violations occurring. The high level operation of the LV CMS, illustrated in Figure 5-1, includes the calculation of network headroom and footroom by the DSO which is then provided to a congestion management provider (CMP). The CMP, which could be a contracted third party such as an aggregator, manages flexible assets (such as EVs) within the LV network, and in the context of the CMS, is responsible for optimising these flexible assets within the network headroom and footroom provided by the DSO.

[57] Headroom is defined as the available network import capacity within three-phase voltage and thermal limits.

[58] Footroom relates to the available network export capacity within three-phase voltage and thermal limits.

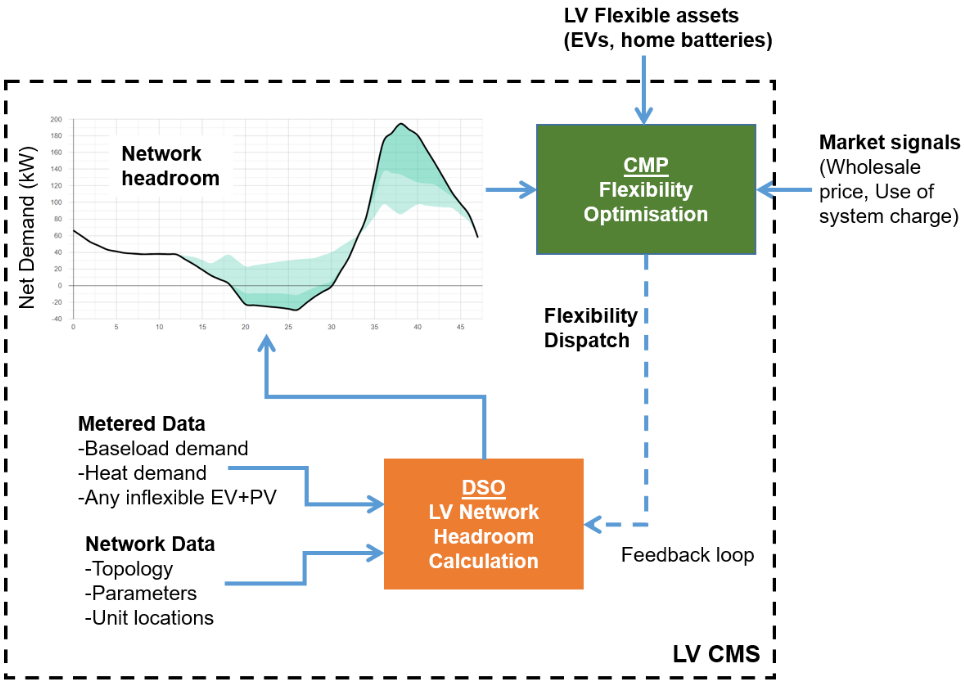

Figure 5-1: LV Congestion management scheme illustration.

The LV CMS will be contracted by zone: a section of LV electricity network, defined as a unique combination of feeder and phase. An illustration of zone labelling is provided in Figure 5-2 for a simplified LV network with a set of three feeders connected to a secondary (11kV/0.416kV) delta-wye transformer. As illustrated, customers in the same zone are connected to the same phase on a given feeder, and their geographical grouping will depend on their assignment by the DNO at the time of connection. An LV network connected to a secondary transformer typically serves between 60 and 900 customers [187] resulting in a range of number of customers per zone from under 5 up to 80.

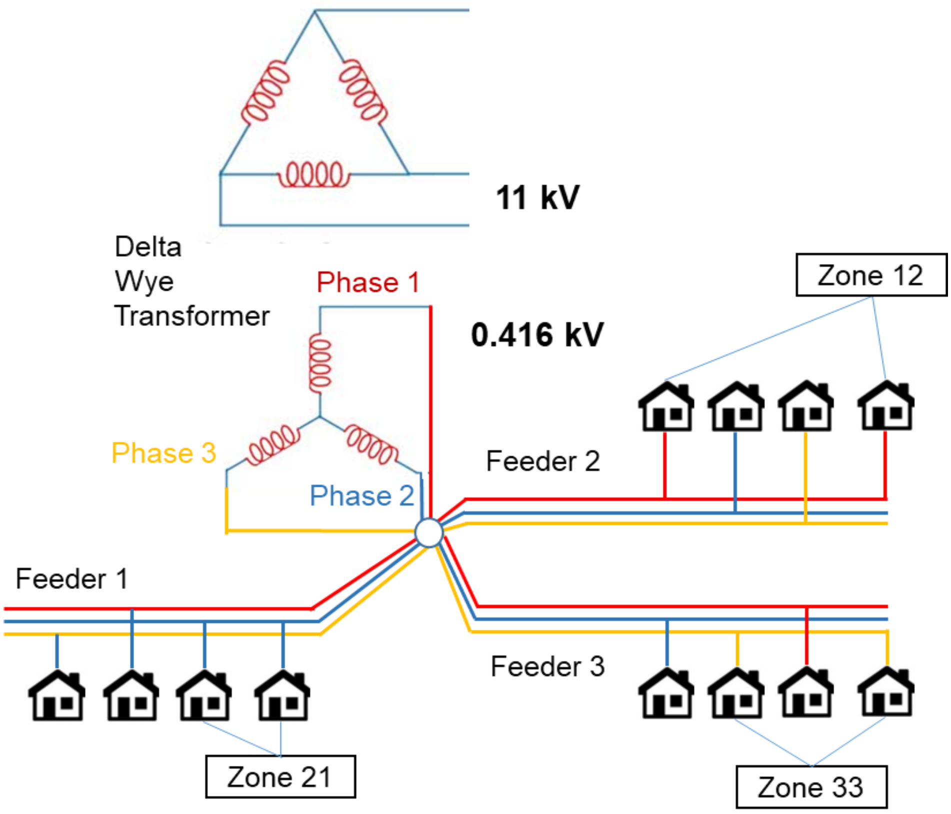

Figure 5-2: Illustration of three feeder LV network zone labelling[59].

The DSO either provides static headroom and footroom profiles for each zone to the CMP based on a worst case (such as maximum winter demand), or dynamic profiles depending on season or temperature forecast. The headroom and footroom calculation requires historic metered demand and PV generation data for all customers, as well as a full LV network model. In the likely event that full customer and network information is not available, estimates can be made based on known customer and network parameters using methods such as those proposed in [135] and [188].

The headroom sets an import limit and the footroom sets an export limit to a zone while respecting three-phase thermal and voltage limits. The contracted CMP for the zone is responsible for maintaining power flow within the headroom and footroom limits. The CMP carries out optimisation of flexible assets over their preferred optimisation horizon which could be day-ahead or intra-day depending on their market objectives and their forecast of available flexibility from assets such as EVs.

[59] Neutral lines and earthing points are not shown.

5.2 Compatibility with DSO-TSO coordination

The communication between the CMP and the *Local market* DSO-TSO coordination scheme outlined in section 3.2.2 is crucial in enabling flexibility from LV (e.g., EV home charging) to be accessed for MV/HV congestion management by the DSO and for transmission level system balancing by the TSO. In the DSO-TSO coordination market timeline illustrated in Figure 3-1, the DSO market manages MV/HV congestion before TSO market gate closure. The CMP will be required to pass power flow positions and upper/lower limits, aggregated to zones, to the DSO prior to gate closure of the DSO market. Flexibility from CMPs could be further aggregated to secondary substation zones (an entire LV network) or even to be part of a portfolio of multiple CMP zones across different network areas, so long as these can be assigned to MV nodes in the DSOs MV/HV network model used in the DSO-TSO coordination scheme.

The system could become significantly more complex if the flexibility offered by customers within a CMP zone is part of another aggregator/BRP portfolio taking part in the DSO-TSO coordination market or providing any other ancillary service. Therefore, within the modelling work of this thesis it is assumed that customers within a zone do not offer flexibility to an aggregator or supplier other than the CMP. The proposed LV CMS maximises access to EV flexibility at all voltage levels and provides a mechanism for access to EV flexibility to the DSO for congestion management and the TSO for system balancing and ancillary services. This is demonstrated in chapter 7 where the LV CMS and *Local market* DSO-TSO coordination models are integrated, and results are presented for an example settlement period. Through the CMPs' communication with the DSO-TSO coordination mechanism, aggregated EV flexibility can also be utilised to provide ancillary services, such as frequency response and reserve, to the TSO.

Having explored the high-level market operation, the detailed methodology of the LV CMS is provided including an example EV optimisation formulation used by the CMP.

5.3 LV congestion management methodology

In the proposed LV CMS methodology, illustrated in Figure 5-1, the DSO determines the headroom and footroom available in LV zones by carrying out three-phase load flow studies on the relevant LV networks with existing (or future in the case of advance planning) levels of inflexible demand and generation. Once the headroom and footroom has been determined by the DSO, this is communicated to the CMP who has responsibility for optimisation of EVs within these limits. Finally, validation of the LV CMS is carried by load flow analysis to check that voltages and currents are within prescribed limits with the inclusion of optimised EV demand.

In this thesis, it is assumed that EVs are the only source of flexible assets connected at LV. Although HPs have the potential to provide flexibility, improvements to building insulation or heat storage are required for significant time shifting of thermal demand [189]. With the levels of insulation in existing UK housing stock, it has been shown that HP operating times could only be shifted within a 60-120 minute window without affecting the home-dwellers comfort, which would have limited effect on flattening the morning and evening HP demand pickups [190]. If combined with small-scale battery storage, there is significant potential for peak shaving of HP demand, for example, in [191] it was found that 100% HP penetration could be achieved without increasing the aggregated peak demand of 100 households if 3 kWh of battery storage was installed per household. In the future, with reduced costs of batteries and/or heat storage and improvements in building thermal efficiency, HPs could be a valuable source of flexibility. However, in [184] it is concluded that, based on modelling data from their HP trials, 'HPs are less suitable for smart optimisation', whereas, 'active control of EVs could have benefits for distribution networks'. Thus, in this thesis HPs are considered as inflexible and instead the more accessible flexibility from domestic EV charging is optimised, including the use of V2G to reduce the peak demand from HPs.

The headroom/footroom calculation and EV optimisation are carried out by zone: defined as a unique combination of feeder and phase (see Figure 5-2). It is assumed that a single aggregator has a contract as a CMP to optimise EV charging to manage congestion within a zone. After initial load flow studies, it was found that the feeder head cable is often a pinch point in terms of thermal rating, and on the same feeder, phases should be treated separately due to differing number of customers on each phase. Therefore, in the LV CMS, a zone is considered to be a section of electrical network with a set of connected customers behind a common 'pinch point'.

The LV CMS methodology, illustrated in Figure 5-3, can be split up into the following steps each of which is carried out per zone on a given LV network:

1. Headroom assessment: determine the headroom and footroom available for EV optimisation based on existing inflexible demand and generation.
2. EV optimisation: EV charging is optimised over a 24h timeframe using available headroom and footroom.
3. Validate results: validation of the 24h EV charging schedule to check that voltages/currents are within network limits.

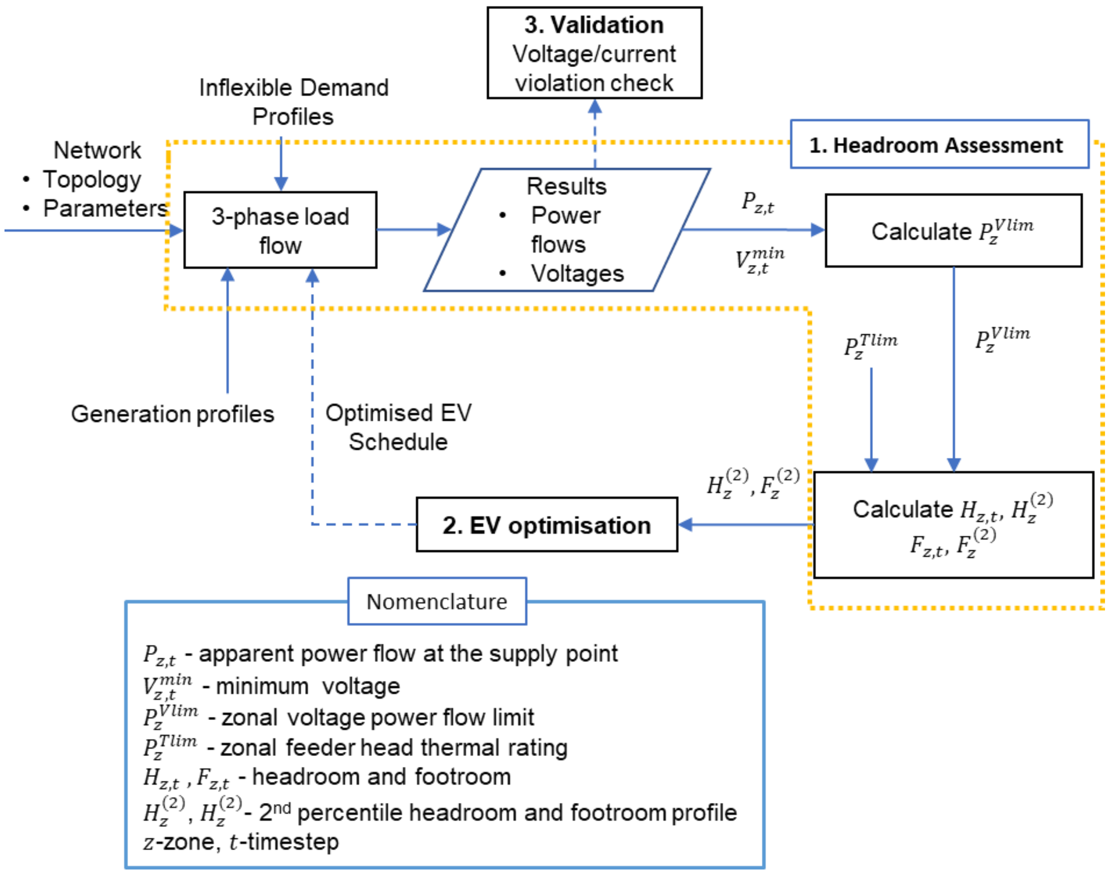

Figure 5-3: LV CMS Methodology

The subsequent sections provide more detail on the headroom assessment, carried out by the DSO, and EV optimisation, carried out by the CMP.

5.3.1 Headroom assessment

To determine available headroom and footroom, load flow studies are conducted over a sufficient timescale to model the range of possible demand and generation scenarios. In this thesis, footroom is the maximum injection (by vehicle to grid) within export limits which is estimated from the power flow plus the rating. For example, if the power flow is 10 kVA (import) and the import/export power flow limit is 10 kVA[60], the headroom is 0 kVA and the footroom is 20 kVA; if the power flow is -5 kVA (export) with a 10 kVA power flow limit, then the headroom is 15 kVA and the footroom is 5 kVA.

The relevant load flow outputs for the headroom calculation are the apparent power flow at the supply point, $P_{z,t}$, and the minimum voltage $V_{z,t}^{min}$ within zone z for each timestep t. The headroom and footroom, $H_{z,t}$ and $F_{z,t}$, are calculated for every zone and timestep based on the power flow at the supply point for the zone, $P_{z,t}$, and the lesser of the thermal or voltage power flow limits, $P_{z,t}^{Tlim}$ and P_{z}^{Vlim} respectively:

$$H_{z,t} = min\left(P_{z,t}^{Tlim}, P_{z}^{Vlim}\right) - P_{z,t} \tag{5-1}$$

$$F_{z,t} = min\left(P_{z,t}^{Tlim}, P_{z}^{Vlim}\right) + P_{z,t} \tag{5-2}$$

where $P_{z,t}^{Tlim}$ is the thermal rating of the feeder head of each zone and P_{z}^{Vlim} is the zonal apparent power flow limit to maintain the zonal minimum voltage above the lower limit of 225 V[61] (0.94 p.u for a base voltage of 240 V).

The zonal power flow limit P_{z}^{Vlim} is estimated using linear regression of $P_{z,t}$ and $V_{z,t}^{min}$. In zones where instances $V_{z,t}^{min}$ < 0.94 p.u occur, P_{z}^{Vlim} is set as the minimum $P_{z,t}$ at which $V_{z,t}^{min}$ = 0.94 p.u. For example, from the apparent power flow vs minimum voltage plot in Figure 5-4, P_{z}^{Vlim} is set at 16.6 kVA.

For export constrained cases (e.g., high PV penetrations in summer months), a more accurate estimate of footroom could be obtained based on the maximum voltage constraint (the export power flow limit corresponding to a maximum voltage of 1.1 p.u.). In the LV network case studies carried out in this thesis, the network is import

60 Assuming the import and export power flow limits are the same, which would be the case for cable limits but is not always the case for transformer power flow limits or voltage based power flow limits.

61 The 225 V lower limit is conservative and corresponds to 0.94 p.u. for a base voltage of 240 V. This is to allow a margin of error to prevent additional EV load from causing voltages to drop below 216 V (the UK statutory minimum voltage) which corresponds to 0.94 p.u for a base voltage of 230 V.

constrained and an approximation of footroom is adequate to prevent vehicle to grid (V2G) injections from causing voltage violations.

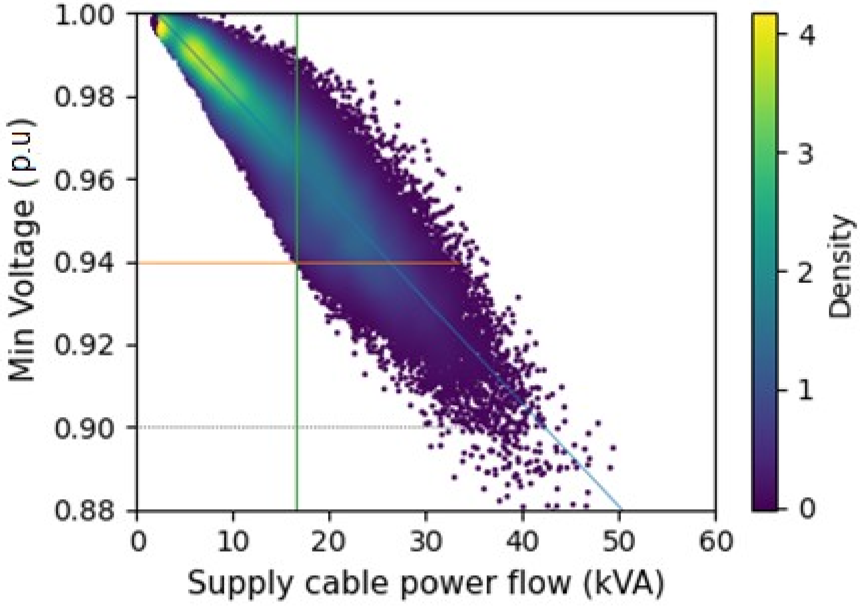

Figure 5-4: Apparent power flow vs minimum voltage for a typical LV network zone with 15 customers.

Commonly at LV, cable ratings are provided in Amps, therefore these are converted into feeder kVA thermal ratings at the feeder header, $P_{z,t}^{Tlim}$, as follows:

$$P_{z,t}^{Tlim} = \frac{I_z^{lim} \times V_{z,t} \times V_{base}}{\sqrt{3}} \times 0.9 \tag{5-3}$$

where $V_{z,t}$ is the voltage at the zone supply node (in p.u), V_{base} is the base voltage (416 V phase to phase is converted to phase to line voltage) and I_z^{lim} is the zone feeder head cable current rating. The 0.9 factor is a safety margin determined empirically to ensure sufficient headroom.

5.3.2 Zonal headroom outputs

Using the zonal headroom per timestep, H_z, the 2nd percentile (P2) zonal headroom[62] profile for day, $H_z^{(2)}$, is determined to provide a worst case assessment of network

[62] This parameter can be tuned, for example the minimum or P5 headroom can be used. The P2 headroom was determined empirically to be the maximum headroom permissible before unacceptable levels of thermal or voltage violations begin to occur.

headroom over the timeseries modelled. The P2 headroom profile ($H_z^{(2)}$) is passed to the CMP to optimise EV charging within the available headroom and prevent network congestion. Likewise, the P2 zonal footroom profile is also passed to the aggregator to set bounds on V2G injection to limit the potential for high voltage or thermal violations.

Figure 5-5 shows an illustrative P2 headroom profile which includes a period of negative headroom in the middle of the day (this does not reflect a realistic headroom profile and is purely for illustrative purposes). To assess the effectiveness of EV V2G in reducing thermal and voltage violations caused by demand (such as HPs) exceeding network capacity, V2G can be used by the CMP to inject power during periods of negative headroom such as that shown in Figure 5-5.

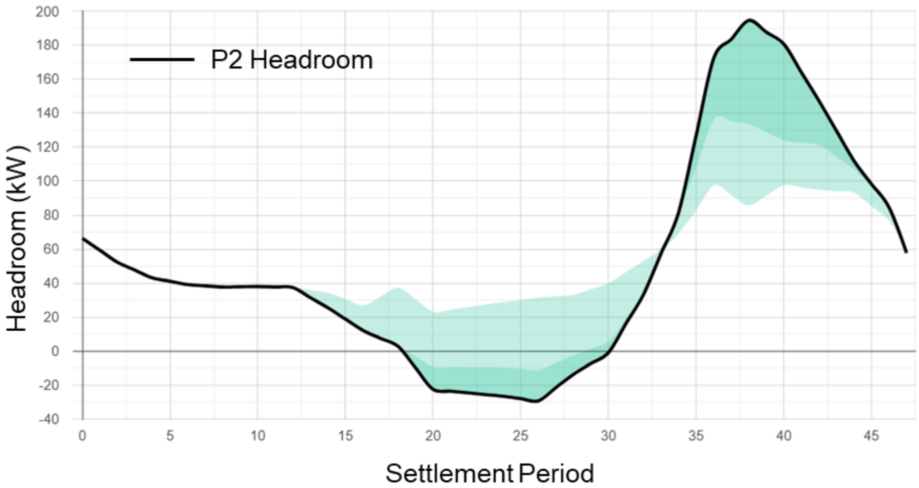

Figure 5-5: Illustrative P2 headroom profile by 48 half hour settlement period (from midnight to midnight).

5.4 EV optimisation

In the LV CMS proposed in this thesis, the CMP has responsibility for managing the charging of EVs within the P2 headroom and footroom limits provided by the DSO. The detail of the remuneration mechanism between the DSO and CMP is not covered in this thesis, however it is envisaged that the CMP is paid by the DSO to maintain the power flow of their EV fleet within the headroom and footroom provided by the DSO and is penalised for any deviations from these limits. If the CMP provides V2G in response to a negative headroom signal from the DSO, the CMP and the EV owners should be rewarded accordingly.

The optimisation strategy of the CMP would include multiple markets such as wholesale power exchanges, ancillary services, the MV/HV DSO congestion management markets (in the DSO-TSO coordination mechanism) and the TSO balancing mechanism. While the CMP would be free to develop their own market optimisation strategy, the LV headroom and footroom provided by the DSO are hard constraints in the proposed LV CMS methodology.

To validate the proposed LV CMS methodology, an example EV optimisation formulation is demonstrated and validated. The optimisation formulation uses EV charging schedules derived from real travel diary data and minimises the cost of charging a fleet of EVs over a 24 hour period.

5.4.1 EV charging schedules

EV charging schedules are derived using a heuristic methodology described in [39], [192] from National Travel Survey (NTS) car-based travel diaries -- making up a dataset of over 3,000,000 trips recorded in Britain between 2002 and 2016 [193]. Charging schedules were synthesised according to the assumption that -- as charging at home is seen to carry negligible inconvenience -- drivers will plug in whenever they arrive home and will seek the maximum gain in state of charge (SoC) allowed by the parking duration, battery capacity and charging power. The energy requirement for each charge event is a function of the EV's travel diary and other charge events that they have taken.

For this thesis, a bank of 10,000 charging schedules (derived from 10,000 car-based NTS travel diaries) is randomly sampled from; these have a range of common battery sizes (24, 30, 40, 60 and 75 kWh) and 7.4 kW chargers. A subset of 5 travel diaries is shown in Table 5-1 for a single day from midday to midday where SoC^S is the initial state of charge at plug-in time and SoC^F is the final SoC at plug-out time. In Table 5-1, EV 9602 has 3 charging ‘windows' over which the EV is plugged in within the 24h optimisation period. These travel diaries are used as an input to the EV optimisation formulation which minimises the cost of meeting each final EV SoC by scheduling the EV charging during times of lowest cost within the plugged-in charging window.

Table 5-1: Daily routine charging schedule for a subset of 5 EVs.

EV ID	Window	Plug-in time	Plug-out time[1]	SoC^S (%)	SoC^F (%)
5694	1	2140	1150	59.3	60
8669	1	1540	1150	4.8	30
9602	1	1540	1700	58.5	60
9602	2	1710	0730	59.3	60
9602	3	1020	1150	51.9	56.5
1931	1	1740	0620	39.5	75
1417	1	1830	1150	23.9	30

[1]Plug-out times before midday are the following morning (optimisation is carried out for 24 hours from midday to midday the following day)

5.4.2 EV optimisation formulation

The EV optimisation problem is to fully charge a set of EVs by the end of a charging optimisation horizon, within the available headroom and footroom, including V2G EV discharge in response to times of high system price. The objective function of the EV optimisation is to minimise the cost of charging the EV fleet within the headroom available over a time horizon T:

$$\min \sum_{t \in T} (c_t^G p_t^G) \tag{5-4}$$

where c_t^G is the grid cost of charging in £/kWh at timestep t and p_t^G is the total energy requirement of all EVs in kWh at timestep t. Subject to the following constraints:

Total EV energy requirement

$$p_t^G = \sum_{e \in \mathcal{E}} (p_{e,t}^C - p_{e,t}^D) \tag{5-5}$$

where $p_{e,t}^D$ and $p_{e,t}^C$ are the discharge and charge for an EV e during time t and $\mathcal{E}$ is a set of EVs.

Zonal headroom and footroom constraints

$$-F_{z,t}^{(2)} \leq p_t^G \leq H_{z,t}^{(2)} \tag{5-6}$$

where $H_{z,t}^{(2)}$ and $F_{z,t}^{(2)}$ are the P2 headroom and footroom in zone z for time t provided by the DSO and calculated in the headroom assessment.

EV SoC constraint

$$SoC_{e,t,w} = \eta p^C_{e,t} - \frac{1}{\eta} p^D_{e,t} + SoC_{e,t-1,w} \tag{5-7}$$

where $SoC_{e,t,w}$ is the SoC of the EV e at timestep t in charging window w, respectively. The SoC is the product of the state of the charge in the previous timestep $SoC_{e,t-1,w}$ and any charge/discharge, $p^C_{e,t}/p^D_{e,t}$, during that timestep. The parameter η is the charging/discharging efficiency which is assumed to be 0.88 as in [39] and the same for both charging and discharging as in [194].

EV final and initial SoC constraints

$$SoC_{e,t_s,w} = SoC^S_{e,w} \tag{5-8}$$

$$SoC_{e,t_f,w} = SoC^F_{e,w} \tag{5-9}$$

where $SoC_{e,t_f,w}$ is the SoC of EV e at timestep, $t = t_f$, for charging window w which must equal the required final SoC, $SoC^F_{e,w}$, specified in the EV travel diaries. Likewise, $SoC_{e,t_s,w}$ is the SoC of EV e at the first timestep, $t = t_s$, for charging window w which must equal the required initial SoC, $SoC^S_{e,w}$, specified in the EV travel diaries.

Maximum charge power constraint

$$p^C_{e,t} = \begin{cases} p^{max}_e \quad , & SoC_{e,t,w} \le \gamma_e \\ \left(\dfrac{1 - SoC_{e,t,w}}{1 - \gamma_e}\right), & SoC_{e,t,w} > \gamma_e \end{cases} \tag{5-10}$$

where p^{max}_e is the charger capacity for EV e and γ_e is 0.8 to represent the constant-current constant-voltage charging power profile typical of EV charging [195].

Maximum discharge power constraint

$$p^D_{e,t} \le p^{max}_e \tag{5-11}$$

The optimisation formulation (5-4) – (5-11) can be written as a Linear Programming (LP) problem and in this thesis it will be solved using the CPLEX solver within OATS [165] optimisation software.

Grid charging price

As previously discussed, the price optimisation carried out by the CMP would be at their own discretion and could involve multiple markets. However, for simplicity, the optimisation formulation in this thesis involves the minimisation of distribution network time of use charges which provides a benefit to the DSO in terms of reducing EV demand at times of peak network demand (represented by the highest network charges). In the EV optimisation strategy developed in this thesis, the grid charging price, c_t^G, over which EV charging is optimised, includes the distribution use of system (DUoS) charges for LV network domestic customers for 2019/2020 from [196]. The DUoS charges are levied by DNOs (via suppliers) to all connected customers on the distribution network to pay for the operation, maintenance and investment in the networks. The DUoS price has been modified to include a morning 'red time band' (the most expensive time period for the DUoS charge), from 06:00 to 08:30 to account for the morning peak HP demand. An example grid price profile is shown in Figure 5-6, which also includes a constant battery degradation cost of 3.2 p/kWh from [197] and a V2G price which is set at 17.5 p/kWh based on the utilisation cost of flexibility (secure service) for domestic customers in Western Power Distribution 'Flexible Power' trial [71]. The V2G price is only applied during periods of negative headroom calculated in the HP headroom assessment, $H_{z,t}^{(2)}$, which in the example shown in Figure 5-6, occurs from 17:00-18:00 and 07:00-08:00. The V2G is aimed at providing injection to reduce thermal and voltage issues caused by peak power demand from HPs, which is indicated by the negative headroom.

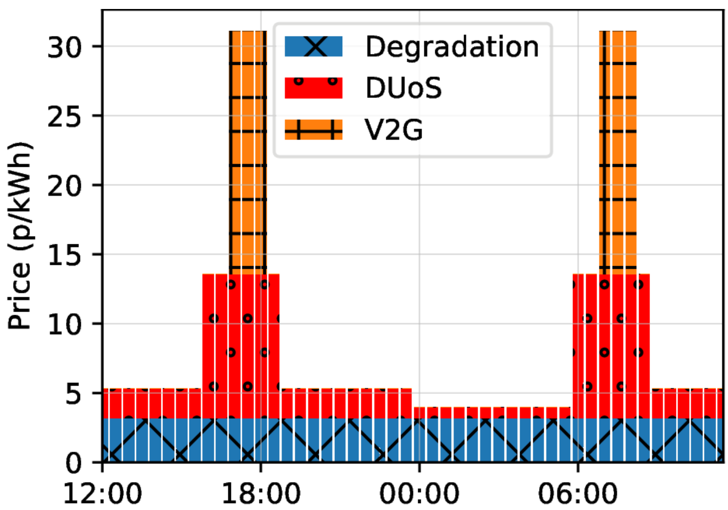

Figure 5-6: Example grid price profile; data [71], [196], [197].

In this EV optimisation formulation, the objective function (5-4) is to minimise the cost of charging a fleet of EVs and it is not aimed to estimate costs to consumers for charging individual EVs or providing V2G. It is assumed the same price is paid for export or import to the grid: in practice this would be unlikely to be the case, however, the symmetric price adopted is adequate for minimising EV charging during times of peak HP demand and instead encouraging V2G dispatch when negative headroom occurs.

Uncertainty in EV charging requirements

To include uncertainty in travel behaviour and EV charging locations, the travel diaries described in section 5.4.1 are randomly sampled to provide variation in driving patterns and EV charge points are randomly assigned to domestic properties based on a distribution of variety of common battery sizes. While this does provide a range of possible demands from domestic EV charging on LV networks, it does not account for forecast uncertainty in the behaviour of EVs ahead of time. This could be captured in future work using probabilistic analysis of the aggregated flexibility available for forward markets (day-ahead and intraday) from EVs for given confidence intervals.

5.5 Validation of LV CMS methodology

To validate the LV CMS proposed in this thesis, load flow results are needed for optimised EV charging within remaining LV network headroom using the LV CMS. The load flow results need to show that network voltages and currents are kept within statutory limits for the methodology to be successful. Furthermore, to assess the effectiveness of the LV CMS in maximising network hosting capacity, the hosting capacity for EVs with the application of the LV CMS is compared with that of dumb EV charging in the absence of the CMS.

To demonstrate the application of the LV CMS with high rates of electrification of heat and transport and low carbon generation, validation is carried out for LV networks assigned with high levels of HP demand (modelled as inflexible) as well as PV generation. As detailed network information are not currently available publicly for LV networks with high levels of HPs or EVs, they must be overlayed onto existing LV network models. The following steps are carried out on a set of LV networks over a winter period.

1. Estimate HP and dumb EV charging hosting capacity in the absence of the LV CMS by randomly assigning HP and EVs to LV networks in penetrations between 0 and 100%. Hosting capacity is defined as the maximum HP/EV penetrations before thermal or voltage violations occur.
2. Estimate HP and optimised EV charging hosting capacity (using the LV CMS) by following the steps of the HP and optimised EV capacity assessments outlined below in sections 5.5.1 and 5.5.2.

5.5.1 Heat pump hosting capacity assessment

Measured smart meter (SM), solar PV and HP demand data is assigned to customers to create realistic demand and generation profiles for a winter period. An 88 day winter period, from 1st December 2013 to 26th February 2014) is modelled corresponding to the availability of PV,SM and HP data. In the HP hosting capacity assessment, voltages and currents are calculated for HP penetrations between 0 and 100% on each LV network using the OpenDSS load flow software.

For the purposes of tractability in terms of network modelling time, while at the same time preserving HP data granularity, 10 minute timesteps have been chosen for both the network modelling and subsequent EV optimisation.

To determine the HP hosting capacity and remaining headroom for EV optimisation in the LV CMS, the steps in Figure 5-7 are followed which incorporates the LV CMS headroom assessment methodology outlined in section 5.3.1.

Figure 5-7: Maximum HP capacity assessment algorithm

1: **for** each network, n, in $\mathcal{N}$

2: **for** each case, c , in $\mathcal{C}$

3: Assign SM, HP and PV profiles to customers based on % penetrations of HP and PV in each case.

4: Run load flow for 88 winter days from 1st December 2013 to 26th February 2014 and extract minimum voltage $V_{z,t}^{min}$ for each zone z for each timestep t

5: **for** each zone, z, in $\mathcal{Z}$

6: Calculate P_z^{Vlim} from simple linear regression of $P_{z,t}$ and $V_{z,t}^{min}$ for the results of all cases.

7: **for** each c in $\mathcal{C}$

Calculate headroom $H_{z,t}$ for each timestep t using (5-1)

Calculate footroom $F_{z,t}$ for each timestep t using (5-2)

Determine the 2nd Percentile (P2) headroom and footroom profiles, $H_{z,t}^{(2)}$ and $F_{z,t}^{(2)}$ as described in section 5.2.1.

Determine HP limit case: defined as the case with highest HP penetration with positive total P2 headroom $\sum_{t \in T} H_{z,t}^{(2)}$

Return P2 headroom and footroom profiles for HP limit case, $H_{z,t}^{(2)}$ and $F_{z,t}^{(2)}$ for use in EV optimisation

In Figure 5-7, $\mathcal{N}$ is a set of representative LV networks, $\mathcal{C}$ is a set of cases of HP penetrations (0-100%) and Z is a set of LV network zones (unique combination of feeder and phase).

The 2nd percentile (P2) headroom, $H_{z,t}^{(2)}$, for the maximum HP penetration case is used in the EV optimisation to determine the maximum EV hosting capacity[63].

5.5.2 Optimised EV hosting capacity assessment

The maximum optimised EV hosting capacity is calculated based on the P2 headroom profile for the maximum HP penetration case determined in the HP hosting capacity assessment. The methodology for EV capacity assessment, summarised in Figure 5-8, involves firstly estimating EV numbers based on available headroom, then optimising the charging of the EVs using charging schedules derived from real travel diary data. The optimisation is repeated 10 times[64] for random samples of EV schedules and the number of EVs is reduced until the EVs can all charge within the available headroom in all 10 cases. The resulting optimised charging profiles for each customer are then validated on the LV networks using load flow to ensure voltage and thermal limits are not exceeded.

[63] This parameter can be tuned, for example the minimum or P5 headroom can be used. The P2 headroom was determined empirically to be the maximum headroom permissible before voltage violations begin to occur.

[64] The repetition of 10 times was determined empirically to ensure charging demand for a given number of EVs can be satisfied for a range of possible EV schedules.

Figure 5-8: Maximum EV capacity assessment algorithm

---

for each z, in $\mathcal{Z}$

  Estimate number of EVs, n^{EV}, per zone based on total daily P2 headroom divided by 95th Percentile (P95) EV charge requirement.

  while Optimisation Result = Fail

    for $i \in \mathbb{R}$, 0< i ≤10

      Optimise EV charging for random sample of n EV charging schedules.

      if All EV's cannot be charged within P2 headroom **then**

        Optimisation Result = Fail

        $n^{EV} = n^{EV} - 1$

Validate EV charge profiles (for entire network) using OpenDSS load flow to verify voltages and currents are within limits (including HP, SM and PV input data).

95th percentile EV charging requirement

The charge requirement for the 95th percentile of daily EV demands is used to make a first estimate of zonal EV hosting capacity based on daily headroom.

The 10,000 EV charge diaries were randomly sampled 1000 times in sets of 10 EVs with the average daily demand calculated for the 10 EVs each time. The resulting histogram of average daily EV charge, Figure 5-9, shows an average of 8.9 kWh/day for a set of 10 EVs with a 95th percentile of 14.2 kWh/day. For comparison, the Electric Nation EV charging trial recorded an average daily charge of 25-35 miles' worth of range [198]. At a typical EV fuel economy of 18-20 kWh/100 km, this equates to an average energy usage of 7.2-11 kWh per day. The P95 figure is used to ensure that the EV optimisation is successful for 95% of possible EV samples sets if sufficient headroom is available for the duration that EVs are plugged in.

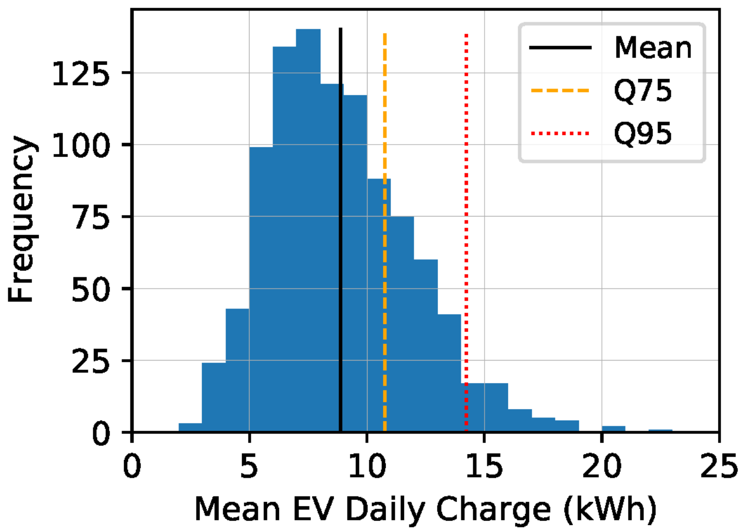

Figure 5-9: Histogram of Mean Daily EV charge for sets of 10 EVs.

5.6 Chapter summary

In this chapter, a LV congestion management scheme (CMS) is introduced which separates the LV network modelling activity carried out by the DSO from optimisation of LV flexibility which can be contracted to a congestion management provider (CMP) such as an aggregator. The market mechanics have been introduced, including consideration of how the methodology could be integrated with the DSO-TSO coordination mechanisms introduced in Chapter 3.

The LV CMS methodology has been presented including the calculation of zonal headroom and footroom which sets the import and export power flow limits for a zone. The headroom and footroom limits have been determined to maintain the network within voltage and thermal limits and are provided by the DSO to the CMP, and the CMP is responsible for keeping the zonal power flow within these limits. To allow validation of the LV CMS, an EV optimisation formulation for use by the CMP, is also presented which minimises the cost of charging a fleet of EVs based on an assumed grid price, within the headroom and footroom limits.

In chapter 6, the LV CMS and EV optimisation will be applied to assessing the capacity of a set of representative LV networks for the electrification of heat and transport. HP and EV hosting capacity will be estimated based on optimised EV charging will be optimised within headroom and footroom limits calculated in the LV CMS.

Chapter 6:

LV Congestion Management Case Studies

The LV congestion management scheme (CMS) described in chapter 5 offers a tractable method of quantifying LV network constraints using a headroom and footroom profile that would be provided by the DSO to a contracted congestion management provider (CMP). In this chapter, the proposed LV CMS is applied to case studies where HP and optimised EV hosting capacities are assessed for a range of representative LV networks. These case studies provide a validation of the LV CMS as well as providing an assessment of the adequacy of existing LV networks for the electrification of heat and transport.

The remainder of this chapter provides the following details of the LV CMS case studies: the representative LV network models; input data of HP, smart meter (SM), PV and EV demand; the methodologies for assessing HP and EV hosting capacity; and finally, results of hosting capacity of the representative LV networks for HPs and EVs, with and without the proposed LV CMS for comparison.

6.1 LV network models

The LV networks utilised in the CMS case studies are taken from the Low Voltage Network Solutions (LVNS) project [187] which published the largest set of publicly available validated LV network models available in the UK. The LVNS models are of areas in the North West of England and are representative of a range of operational network topologies observed by network operators.

There are 25 LVNS networks models with a total of 7539 customers (also referred to as loads) and 128 feeders. A histogram of number of customers per zone (defined in this thesis as a combination of phase and feeder) is shown in Figure 6-1. The number of customers per zone provides a strong indication of the levels of loading on each feeder and phase of an LV network and is expected to have a significant bearing on the HP and EV hosting capacity. The histogram shows that 75% of zones have fewer than 26 customers, the median number of customers per zone is 13.5, and 5% of zones have more than 54 customers. This indicates that the vast majority of zones in the 25 LVNS networks have a reasonably low number of customers whereas a minority have a large number and would therefore be more likely to experience thermal and voltage violations with higher penetrations of HPs and EVs.

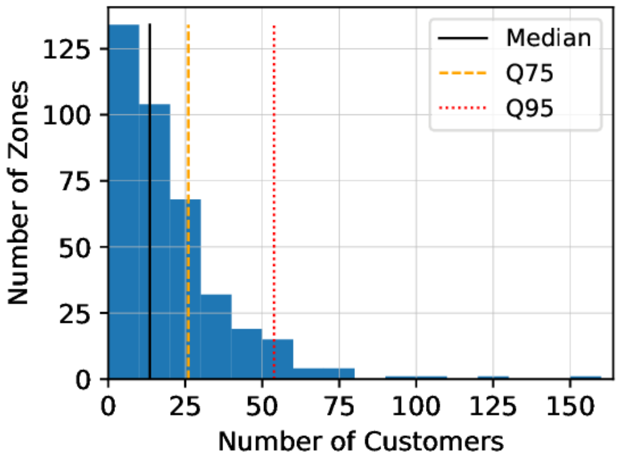

Figure 6-1: Histogram of number of customers per zone for 128 LVNS feeders; data: [187].

A subset of five networks has been selected to represent the range of number of customers per zone in the 25 LVNS networks, as number of customers has been found to be a significant factor in LCT hosting capacity [199]. These five networks (with a total of 34 feeders) are summarised in Table 6-1 and the reasons for their selection are outlined in the following.

Table 6-1: Summary of subset of representative LVNS networks selected for modelling.

Network	Total Loads	Total zones	Median loads/zone	Max loads/zone	Transformer Rating (kVA)
Network 1	200	12	14.5	28	750
Network 5	335	24	9.5	55	500
Network 10	64	18	3	8	1000
Network 17	883	21	41	78	1000
Network 18	328	27	11	23	750

Network 1 has a median number of customers per zone close to the median of all LVNS feeders (13.5 customers per zone). However, there is a significant difference in number of customers between zones: for example, two zones in *Network 1* have more than 26 customers putting them in the highest 25% of number of customers for all LVNS zones. *Network 1* provides an example of typical number of customers per zone but also includes some more heavily loaded zones where LCT hosting capacity may be reduced. The single line diagram for this network is shown in Figure 6-2.

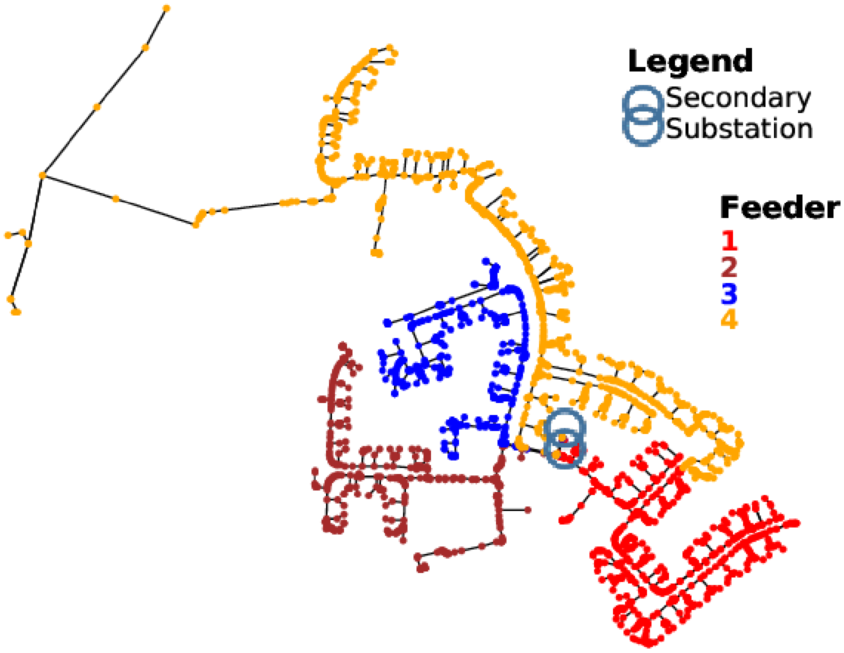

Figure 6-2: LVNS Network 1.

Network 5 displays extreme variation between zones: 18 of 24 zones have fewer customers than the LVNS median but three zones have more than 40 customers putting them in highest 10% of zones in the LVNS networks in terms of number of customers. It is expected that the LCT hosting capacity of *Network 5* will be reduced due to violations in the most heavily loaded zones. The single line diagram for this network is shown in Figure 6-3.

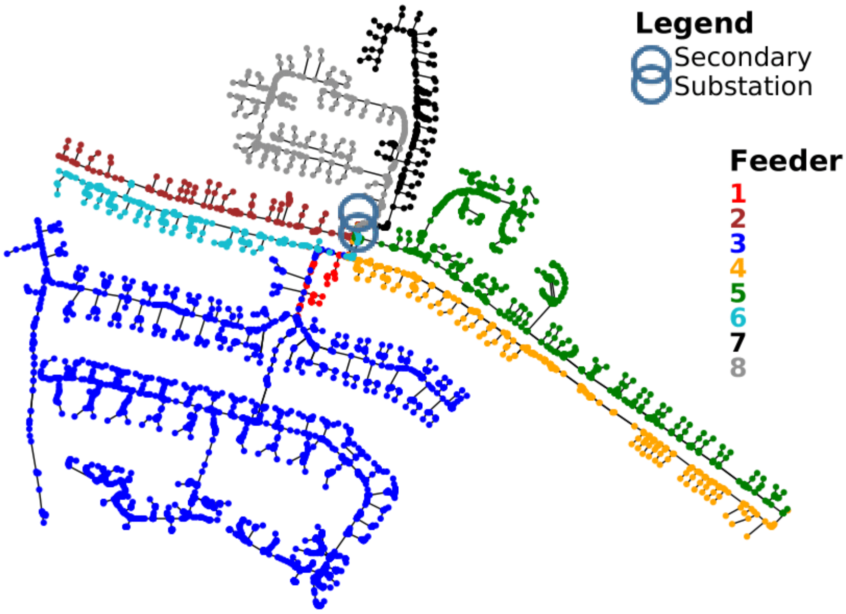

Figure 6-3: LVNS Network 5.

Network 10 has a small number of customers (64) and is not expected to have any issues with hosting 100% LCTs. In [199], 50% of LVNS feeders did not display any issues for up to 100% LCTs and the zones in *Network 10* all have number of customers in the lowest 25% of LVNS zones. The single line diagram for this network is shown in Figure 6-4.

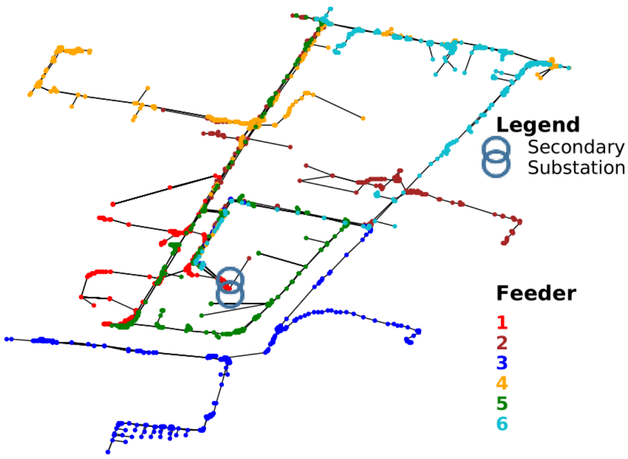

Figure 6-4: LVNS Network 10.

Network 17 has the most customers of all the LVNS networks (883) and 16 of 21 zones have more than 26 customers (the 75th percentile of number of customers in all LVNS zones) and 5 zones have number of customers in the highest 5% of all the LVNS zones. This network is expected to have the lowest hosting capacity for HPs and EVs of all those modelled. The single line diagram for this network is shown in Figure 6-5.

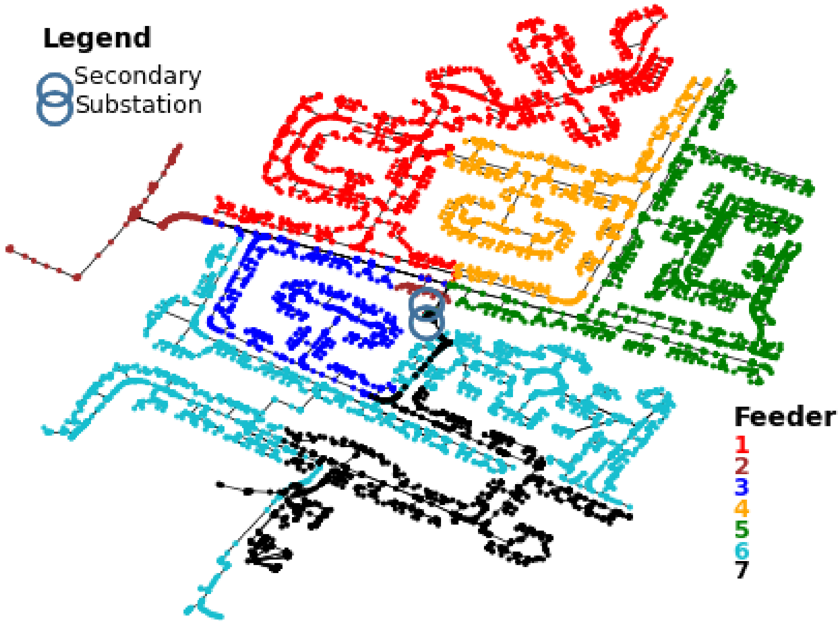

Figure 6-5: LVNS Network 17.

Network 18 is an example of a network with an average total number of customers (328 compared to the mean of 302 for all LVNS networks) spread fairly evenly across 9 feeders. The median number of loads per zone is lower than the median of all LVNS networks and all zones in *Network 18* have number of customers in the lowest 25% of all LVNS networks. The customers are more evenly spread between zones in this network than in *Network 5* (which has 325 customers), hence this network is expected to have a higher hosting capacity. The single line diagram for this network is shown in Figure 6-6.

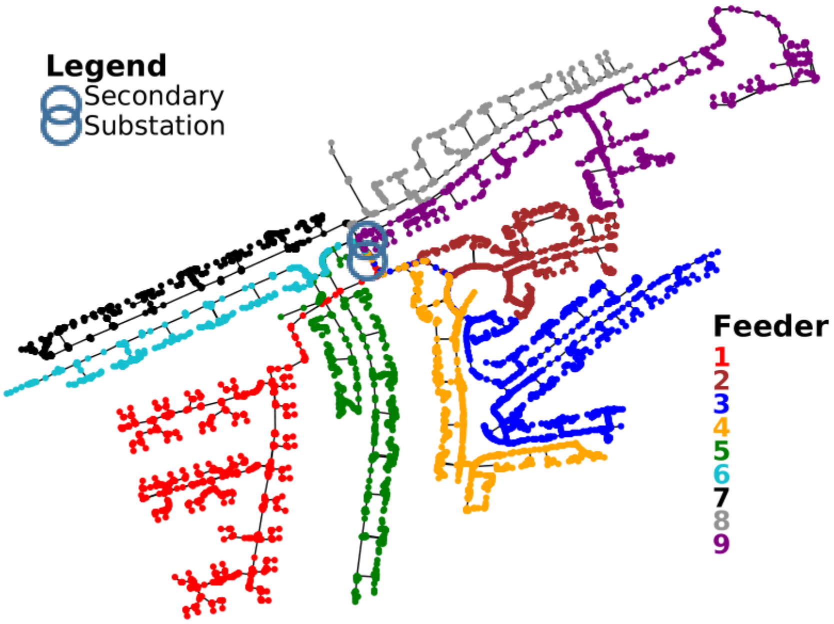

Figure 6-6: LVNS Network 18.

The LVNS OpenDSS networks supplied by [187] are produced from GIS data and often have a large number of redundant branches and nodes that do not enhance electrical representation of the network. In these case studies, condensed network models are used from [200] which have been validated as producing results for voltage with a relative error of no more than 3×10^{-9}%. Each network is supplied from a 11/0.416 kV secondary transformer which is represented in the model. The tap position of each transformer is set at the nominal value and the transformer thermal ratings are shown in Table 6-1. The voltage source is set at the 11 kV side of the secondary transformer with a supply voltage of 1 p.u. The three phase and single phase short circuit currents (ISC3 and ISC1) for the voltage source are set at the LVNS network default values of 3000 A and 2500 A, respectively. Smart meter (SM) and HP loads are modelled as having a 0.95 power factor (lagging) [65] and PV generators have a unity power factor. EV charging is modelled as having a 0.98 power factor (lagging) which was found to be the typical EV charging power factor in a trial of 221 residential EVs [201].

[65] HPs could have a power factor lower than 0.95 due to the effect of a booster heating switch [245], however, as HP power factor and reactive power data was unavailable, HPs are assumed to have a power factor of 0.95.

6.2 Case study input data

Metered data has been used as far as possible to provide a realistic estimate of the hosting capacity of LV networks for HPs and EVs. Data was available for HP, SM and PV over the same time period (December 2013 to February 2014), and dumb EV charging profiles were synthesised using the EV travel diaries described in section 5.4. Each of the different categories of data are described in the following sub-sections.

6.2.1 Heat pump data

This thesis focuses on the headroom during winter for networks with high penetrations of HPs which are considered as inflexible, however the methodology could be adapted to consider available footroom with summer PV output or a combination of both.

The HP profiles have been taken from the UK government Renewable Heat Premium Payment Scheme [202] which contains 2 minutely data for 700 HPs between October 2013 and March 2015. The data has been filtered to include ASHPs and ground source HPs (GSHPs) and to only include full datasets (HPs with data for >90% of timesteps) for 88 days of winter modelled from 12th December 2013 to 26th February[66] 2014 which reduces the number of HPs to 106. Of the 106 HPs, 78 of them were ASHPs and 28 were GSHPs. HP demand for space heating and water heating are provided separately in the RHPPS data and are combined and converted from Wh/2min into kW using the following:

$$P^{hp} = \frac{E^{hp} + E^{dhw}}{1000} \times \frac{2}{60} \tag{6-1}$$

where P^{hp} - HP power demand (kW), E^{hp} - Energy for the HP unit (Wh/2min) and E^{dhw} - Energy for domestic hot water (Wh/2min). The HP data has been resampled from 2-minutely to 10-minutely timesteps by sampling the demand every 10 minutes.

[66] The period of 1st of December to 26th February was chosen as it includes the days with the highest 10-minutely mean HP demand for the 106 HPs in the filtered HP data. HP data from winter 2014 was available but not used as the number of HPs will full datasets (HPs with data for >90% of timesteps) in winter 2014 was reduced to 67 and furthermore, the 10-minutely median and 95th percentile HP demand for the winter 2014 dataset was lower than for 2013.

In Figure 6-7, the HP profiles show the expected morning and early evening pick-ups at around 06:30 and 16:00. In the LV CMS case studies, EV charging will be optimised using the available headroom in a network zone which will be limited during the morning and evening peak HP demand. An important question addressed in these case studies is to what extent V2G can be used to reduce these peaks depending on the travel diaries of EV customers (detailed in section 5.4).

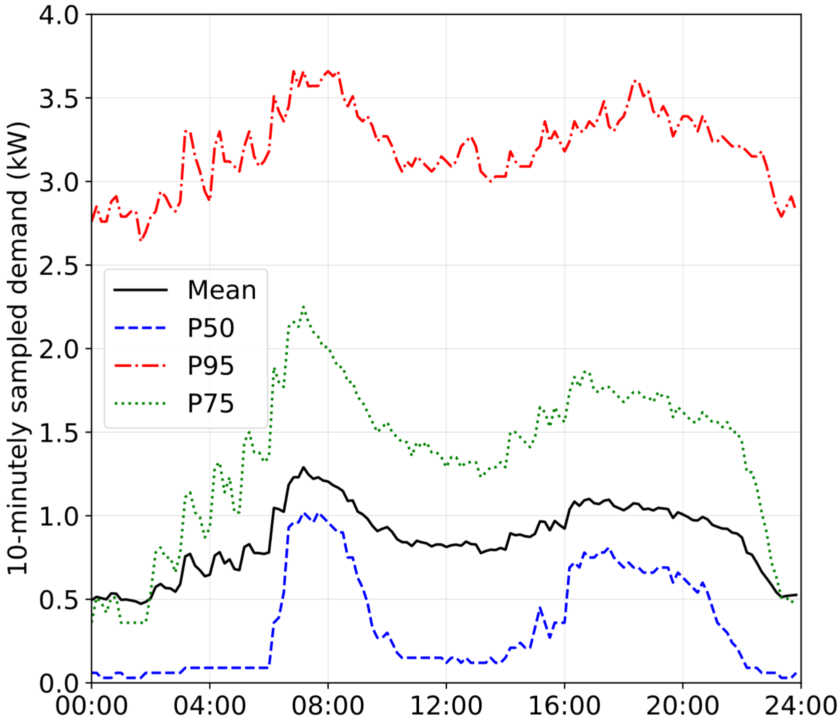

Figure 6-7: Mean, median (P50), 75th percentile (P75) and 95th percentile (P95) demand for 106 HPs from 12th December 2013 to 26th February 2014; data: [202].

A histogram of mean winter HP daily demand, produced from the 10-minutely HP demand data for 106 HPs from 12th December 2013 to 26th February 2014, is shown in Figure 6-8. The mean winter HP demand is 20.7 kWh/day which is significantly higher than the mean daily demand of 13.96 kWh/day for January reported in another UK HP trial [203] for ASHPs only. Within the 106 HPs sampled there is a large variation in demand (both in power and energy). Figure 6-8 shows that the mean daily demand is over 45 kWh/day for four of the HPs which is more than double the average. Two of these HPs were domestic ASHPs with installed capacity of 16 kW, one was an ASHP with 12 kW capacity, and one was a GSHP with 12 kW installed capacity.

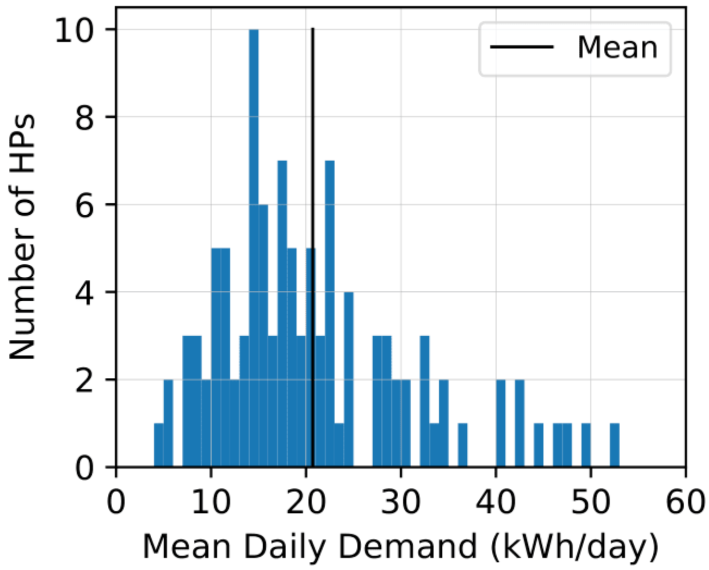

Figure 6-8: Histogram of mean daily HP demand ; data: [202].

This HP data will be used, along with SM and PV data to estimate the hosting capacities on the representative LV networks for HPs, and for calculating the remaining headroom available for EV optimisation.

6.2.2 Electricity smart meter data

A subset of SM data was taken from the Low Carbon London (LCL) SM data set [204] which contains half hourly electricity demand data for 5,567 households between 2011 and 2014. The LCL SM data is labelled according to the CACI Acorn Group[67] consumer classification approach and 300 of each of the 'Adversity', 'Comfortable' and 'Affluent' profiles have been randomly selected which have full data-sets for the 88 days modelled (1st Dec 2013 to 26th Feb 2014).

A minority of customers were observed to have a high overnight demand which is most likely because of overnight storage heating although no contextual information was available. Figure 6-9 shows that there is a large increase in demand at midnight for these customers, which suggests the action of a timer and is consistent with storage heater overnight operation with an Economy tariff. On this basis, customers with these profiles have been removed from the SM sample set to prevent heat demand being added twice when HP demand is added to the SM demand.

[67] See https://acorn.caci.co.uk.

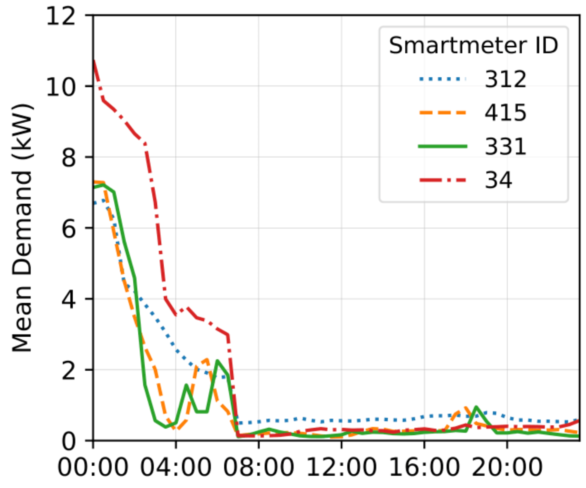

Figure 6-9: Mean SM demand of four customers with high overnight demand for winter period (1st Dec 2013 - 26th Feb 2014); data: [204].

With the high overnight demand customer profiles removed, the mean of the remaining customer profiles of each Acorn class for the winter period modelled are comparable to the 1997 Elexon winter weekday class 1 domestic electricity demand profiles from [205]. This is shown in in Figure 6-10. The Elexon class 2 profile shown in the figure is for customers with the Economy 7 tariff (usually with storage heating) which display the same increase in demand after midnight as seen in the high overnight demand customers.

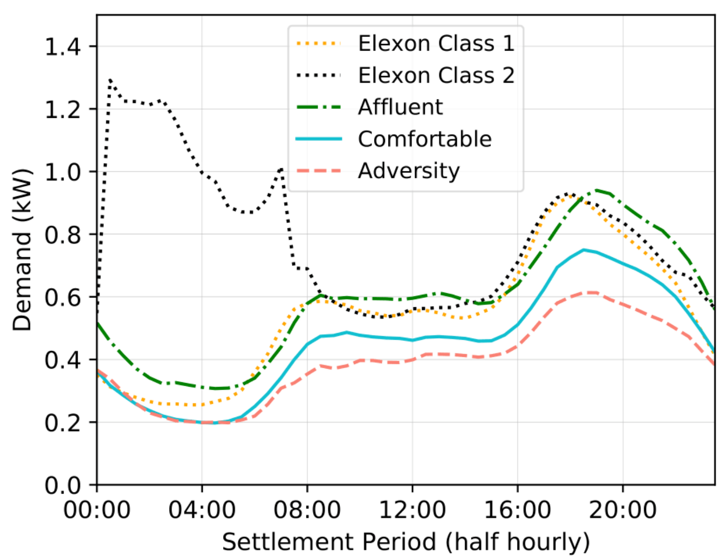

Figure 6-10: Mean SM demand of 300 customers of each Acorn group for winter period (1st Dec 2013 - 26th Feb 2014) along with the Elexon winter weekday class 1 and 2 load profiles; data: [204], [205].

6.2.3 PV data

Although the focus of this case study is on LV network hosting capacity for winter HP and EV demand, domestic PV generation is included as it is likely to increase in uptake in line with HPs and EVs and may positively impact on HP/EV hosting capacity.

The distribution of PV capacities has been calculated from domestic PV installations with feed in tariffs in the UK [206] as of December 2019. The resulting histogram of PV capacity for 1000 customers sampled using this distribution is shown in Figure 6-11.

PV output profiles are created from London Datastore metered PV data [207]. For the 88 days modelled, 4 of the 6 PV sites in [207] had a sufficiently complete set of data over this period, the daily PV output profiles for these 4 sites are shown in Figure 6-12. The PV data was resampled from hourly to 10-minutely resolution using linear interpolation and normalised by dividing the output by the stated capacity of each site from [207]. The capacities of Alverston Close, Bancroft Close, Maple Drive East and the YMCA are 3, 3.5, 4, 0.45 kW, respectively.

These normalised profiles were then assigned randomly to PV customers in the various simulation studies to follow and capacities were assigned according to the proportions shown in Figure 6-11.

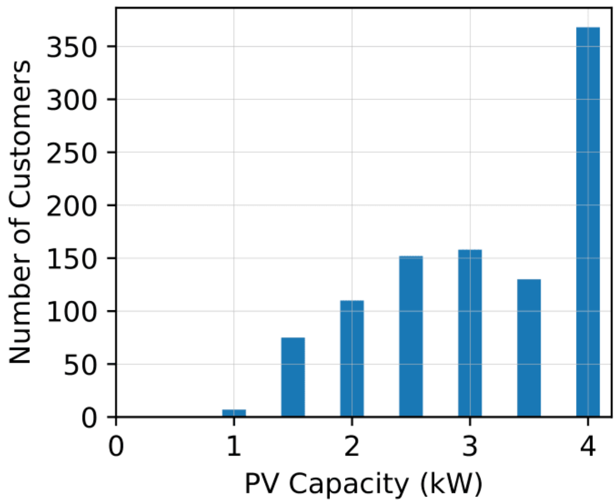

Figure 6-11: Histogram of PV capacities from domestic PV installations with feed in tariff; data: [206].

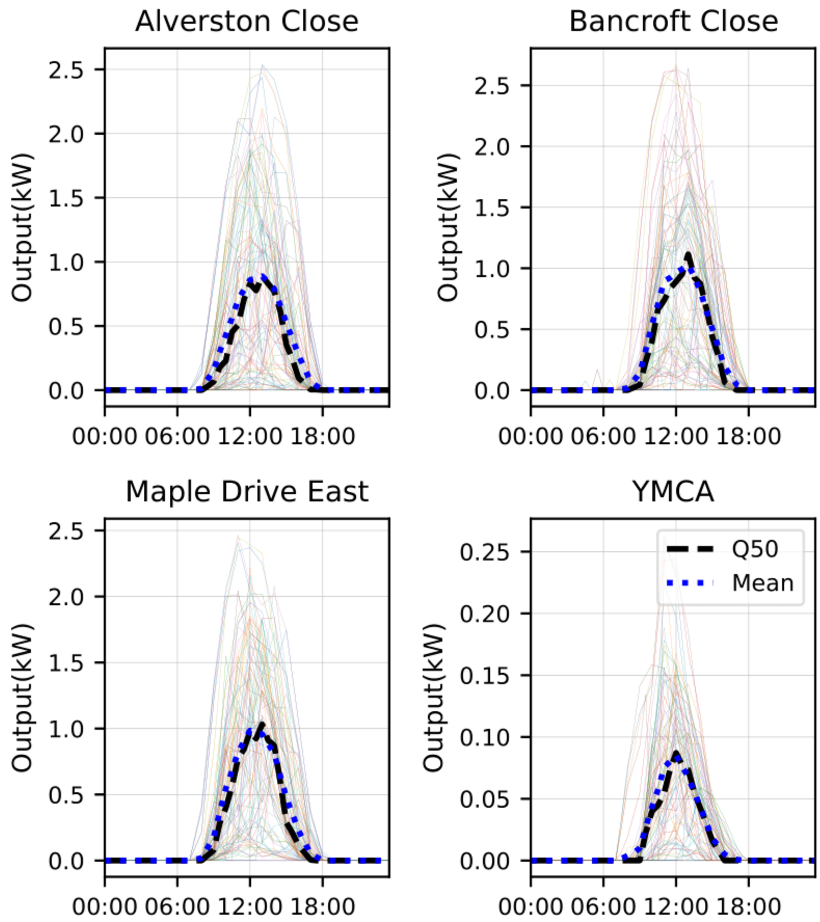

Figure 6-12: Daily PV profiles for four PV sites with median and mean output for 88 days from 1st Dec 2013 to 26th Feb 2014; data: [207].

6.2.4 Dumb EV charging profiles

Dumb EV charging profiles have been calculated from the same travel diaries used in the EV optimisation, and charging power is calculated from:

$$p_{e,t}^{C} = \begin{cases} p_e^{max} , & SoC_{e,t,w} \le \gamma_e \\ \left(\frac{1 - SoC_{e,t,w}}{1 - \gamma_e}\right), & SoC_{e,t,w} > \gamma_e \end{cases} \tag{6-2}$$

assuming EVs charge at full $p_{e,t}^{C}$ from the moment they are plugged in until they are fully charged. Using this method, 10,000 daily EV charging profiles were produced, from which a unique profile was used for every EV and every day simulated to capture diversity of charging behaviour. The median and mean of the 10,000 daily charging profiles is shown in Figure 6-13. This shows that the peak charge demand occurs around 18:40 and there is a significant overlap of the period of the highest mean EV charge and evening HP demand, between 16:00 and 21:00.

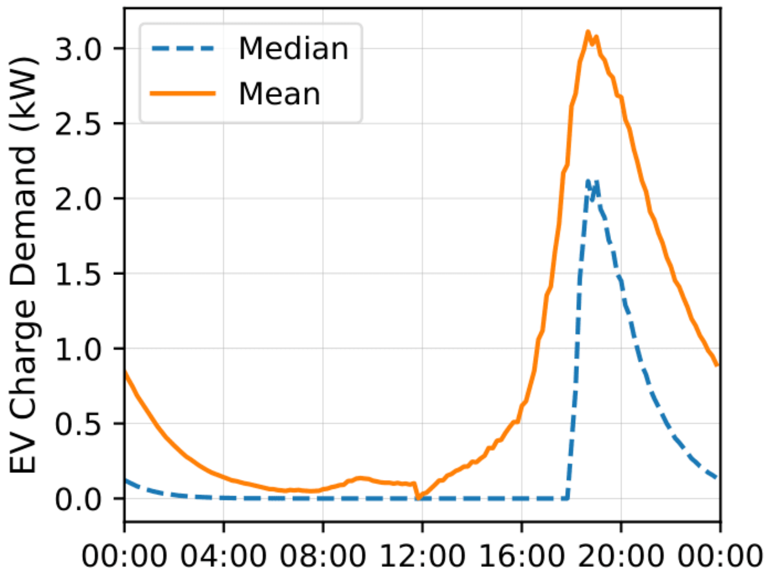

Figure 6-13: Median and mean daily EV dumb charging profiles from 10,000 daily travel diaries.

These dumb EV charging demand profiles are applied to customers on the representative LV networks and the hosting capacity for dumb charging of EVs is compared with optimised charging as part of the LV CMS.

6.3 Results and discussion

The LV CMS proposed in this thesis has been applied to maximising the capacity of LV networks for the decarbonisation of heat and transport. The hosting capacities for HPs and EVs on five LV networks have been estimated based on the HP hosting capacity assessment and optimised EV hosting capacity assessment methodologies presented in sections 5.5 and 5.5.2.

To carry out the HP and EV hosting capacity assessment on the set of five representative LVNS networks, simulations are run for the following penetrations of HPs and PV for 88 days of winter 2013:

- 0% HP penetration. 0% PV penetration.
- 25% HP penetration. 0% PV penetration.
- 50% HP penetration. 25% PV penetration.

- 75% HP penetration. 25% PV penetration.
- 100% HP penetration. 50% PV penetration.

For the analysis of HP capacity in the absence of EVs, the HP hosting capacity is determined by the maximum penetration of HPs without thermal or voltage violations without applying the LV CMS. The same process is used in assessing the HP and 'dumb' EV hosting capacity with the inclusion of dumb EV charging profiles. The HP and optimised EV hosting capacity is estimated using the methodologies presented in sections 5.5 and 5.5.2 and applies the LV CMS methodology outlined in section 5.3.

In summary, results are presented for the following three cases:

- HPs in the absence of EVs (without the proposed LV CMS)
- HPs and 'dumb' or uncoordinated EV charging (again without the proposed LV CMS)
- HPs and optimised EV charging with the application of the proposed LV CMS

To consider the potential for the requirement for network reinforcement for typical LV networks, analysis is also carried out on the relationship between the number of customers in a zone (unique combination of feeder and phase), and the percentage of thermal or voltage violations at different HP and EV penetrations.

6.3.1 Heat pump hosting capacity

For baseline studies without the LV CMS, hosting capacity is determined by the maximum penetration (from the cases modelled), that can be accommodated before voltage and thermal violations occur. Results of low voltage and thermal violations are provided for all networks (except *Network 10*[68]), along with HP hosting capacity in the absence of EVs. This provides an insight into the requirement for network upgrades to achieve high penetrations of HPs, the headroom available for EVs, and the opportunity for V2G to reduce the requirement for network upgrades.

[68] *Network 10* is omitted as no low voltage or thermal issues occurred at any HP penetration. This is due to *Network 10* having a small number of customers (fewer than 8 customers in any zone).

6.3.1.1 Low voltage violations

Low voltage violations with number of customers for 100% HP penetration are presented in Figure 6-14. For zones with fewer than 21 customers, there were very few instances of low voltage problems for any penetration of HPs. For 50%, 75% and 100% HP penetrations, the maximum % of timesteps with low voltage observed in any zone with fewer than 21 customers was 0.02%, 0.48% and 1.28% respectively. For reference, a zone with 21 customers is equivalent to a balanced feeder with 63 customers, however as most of the 128 LVNS feeders are not balanced, it is useful to consider hosting capacity by zone rather than feeder.

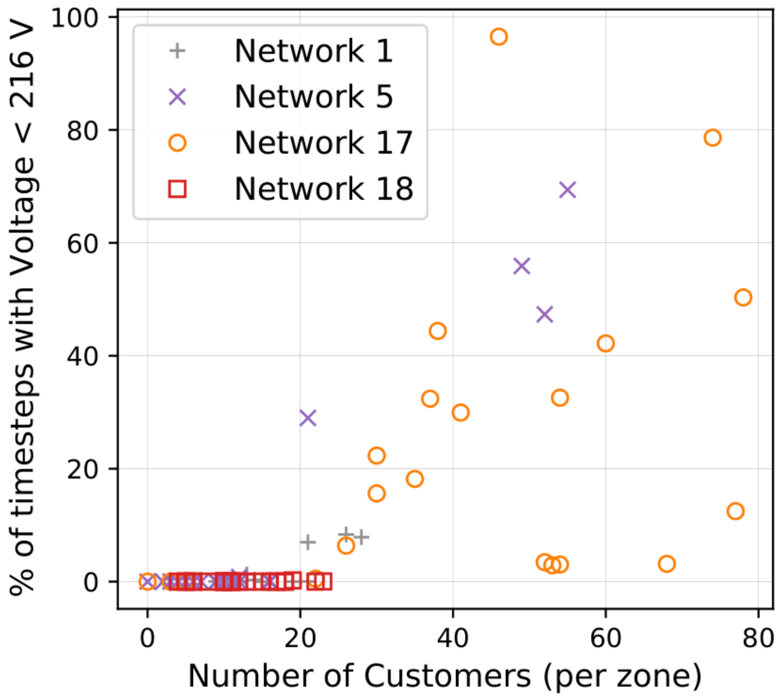

Figure 6-14: Low voltage (<216 V) violations (as a percentage of simulated timesteps) for winter 2013 against number of customers per zone for 100% HP penetration.

Beyond 21 customers, low voltage problems become more prevalent for 25% HP penetrations and upwards, generally increasing in frequency with increasing number of customers and HP penetration (see Figure 6-15). For 0% HPs, with SM demand only, there were four zones which encountered voltage problems, three in *Network 17* and one in *Network 5*. These zones had 0.02%, 0.02%, 0.12% and 22.4% of timesteps with low voltage violations corresponding to number of customers of 35, 55, 74 and 46, respectively.

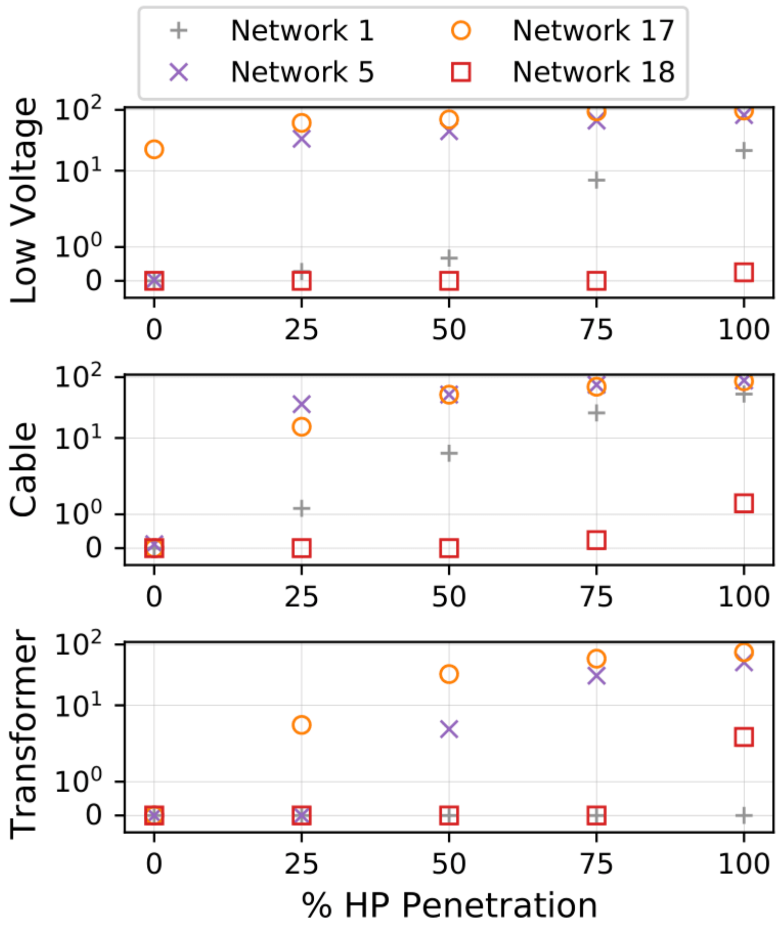

Figure 6-15: Low voltage, cable, and transformer thermal violations (as a percentage of simulated timesteps) for winter 2013 against HP penetration[69].

The relationship between number of customers and low voltage violation percentage is not linear, and in the case of 0% HPs, the zone with the most violations (22.4% of timesteps) does not have the largest number of customers. On this basis, number of customers alone can only provide a crude prediction of the likelihood of low voltage violations, namely a low likelihood below 21 customers and higher likelihood above 21 customers.

6.3.1.2 Thermal violations

Figure 6-16 shows that, as with voltage problems, instances of cable overcurrent were seen in zones with 21 customers and above and Figure 6-15 shows that cable thermal overloads were more probable than the transformer rating being exceeded at a given

[69] In each plot, the y-axis is a symmetric log scale which is linear between 0 and 1 (to allow values of zero and close to zero to be plotted)

HP penetration for all networks (with the only exception being *Network 18* at 100% HP penetration). For 25% HP penetration and below, the transformer limit is exceeded only for *Network 17*. At 50% HP penetration and above, the transformer limits become more of a bottleneck for *Network 5*, *Network 17* and to a lesser extent *Network 18*.

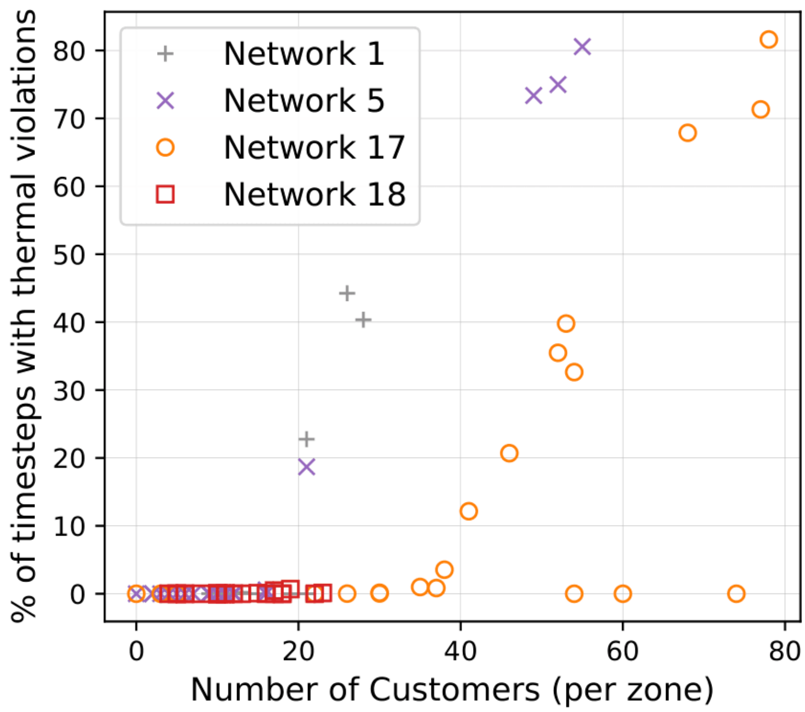

Figure 6-16: Cable thermal violations (as a percentage of simulated timesteps) for winter 2013 against number of customers per zone for 100% HP penetration .

Overcurrent issues were observed most frequently for lines with ratings below 400 A. In [27], a 400 A current limit has been assumed for all lines, due to an assumed 400 A LV feeder fuse rating and in [199] thermal loading was only considered for the head of the feeder. In the LV network case studies in this thesis, ratings are assigned to all cables using cable data from [208] and line codes from the LVNS OpenDSS model data. In the case studies carried out, the most frequently overloaded lines were the feeder head cables as they carry the total current for all loads connected in each feeder. On this basis the feeder heads on the studied networks were classed as ‘pinch points' which were used to calculate headroom (along with the voltage power flow limits) for use in the LV CMS EV optimisation.

6.3.1.3 Heat pump hosting capacity

Table 6-2 shows the network hosting capacity for HPs in the five LV networks modelled. An overall 25.4% HP penetration can be achieved across all five networks with thermal violations in up to 0.5% of timesteps, and no voltage violations. It is assumed thermal violations are acceptable in up to 0.5% of timesteps without causing damage to cables and transformers, however, voltage violations are not tolerated due to the minimum voltage of 216 V being a statutory requirement [209]. It is important to note that these figures are based on modelling of HP penetrations per zone in increments of 25% (as per the cases modelled). The HP capacity estimates in these case studies are conservative and to gain a more accurate estimate, smaller increments of HP penetrations than those used in this work could be modelled. For example, in the case of *Network 17*, transformer thermal violations occurred in 4.8% of timesteps at 25% HP penetration (see Figure 6-15), which reduced the HP hosting capacity to 0%, however the maximum penetration of HPs in *Network 17* would be between 0 and 25%.

Table 6-2: Hosting capacity of five representative LV networks for HPs.

Network	HPs	%	Total Customers
Network 1	107	53.5	200
Network 5	54	16.1	335
Network 10	64	100	64
Network 17	0	0	883
Network 18	235	71.6	328
Total	460	25.4	1810

As previously highlighted, the hosting capacity in an individual zone is affected by the number of customers, and zones with 21 customers per zone have a low probability of thermal or voltage violations up to 100% HP penetration. *Network 10* and *Network 18* have predominantly less than 21 customers (see median and maximum number of customers data in Table 6-1) and can host 100% and 71.6% HPs, respectively. However, *Network 1, Network 5* and *Network 17*, have zones with larger numbers of customers per zone (see Table 6-1), and especially in the case of *Network 17*, this severely restricts the possible penetration of HPs.

6.3.1.4 Network upgrade requirement

Based on the case studies of five LV networks in this thesis, thermal and voltage issues have very low probability in zones with 21 customers for any HP penetration. This suggests that network upgrades would be less likely to be required for 100% HP penetration in zones with less than 21 customers than for zones with a greater number of customers. Figure 6-17 shows a histogram of number of customers per zone for the 34 feeders studied across the five LV networks. The histogram shows that 75% of the network zones have fewer than 21 customers which suggests that network upgrades would not be required for the majority of the zones in the five LV network zones studied.

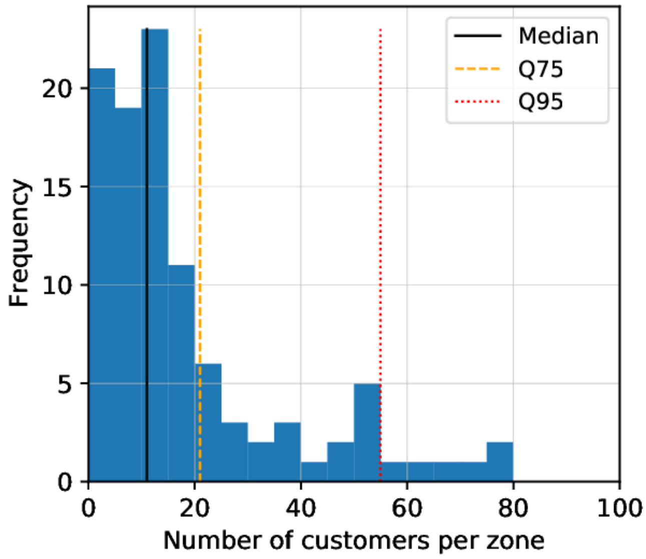

Figure 6-17: Customers by zone for the five representative LVNS networks with 34 feeders and 102 zones (each feeder has 3 zones).

Operationally, network upgrades will be carried out by DNOs at feeder level, rather than on an individual phase, and as 55% of feeders in the 25 LVNS networks have a maximum of 21 customers in any zone, the majority of the LVNS network feeders are unlikely to require upgrade for up to 100% HP capacity. However, Figure 6-15 shows that transformer violation occur for *Network 1* and *Network 5* at 50% HP penetration, and the secondary transformer would require upgrading for three of the five LVNS networks for 100% HP penetration.

6.3.2 Heat pump and dumb EV charging hosting capacity

To provide a baseline for comparing the performance of the LV CMS, the hosting capacity of five representative LV networks for HPs and dumb EV charging is provided. Results of voltage and thermal violations are included for dumb EV charging for all representative networks (except *Network 10*[70]) at different penetrations of HPs and EVs. As in the HP case, hosting capacity is determined from the maximum penetrations (from those modelled) of EVs and HPs without thermal or voltage violations.

6.3.2.1 Voltage and thermal violations

Using the dumb charging profiles described in section 6.2.4, voltage and thermal impacts were assessed for HP penetrations of 0-50% in 25% increments and EV penetrations from 0-50% in 10% increments for December 2013 which corresponds to 4321 10-minute timesteps for each combination of EV/HP penetration.

Figure 6-18 shows the frequency of low voltage, cable thermal and transformer thermal violations (as a percentage of the timesteps modelled) with EV penetration at 25% HP penetration. With the addition of EVs, thermal violations become more frequent than the HP only case, and transformer thermal violations occur on *Network 5*, *Network 17* and *Network 18* beyond 30% EVs for 25% HPs. *Network 17* is unable to accommodate even 10% EVs without the transformer being overloaded with 0% HPs and similarly transformer violations occur with 20% EVs at 0% HPs on *Network 5*.

[70] *Network 10* is omitted as no low voltage or thermal issues occurred at any HP or EV penetration. This is due to *Network 10* having a small number of customers (fewer than 8 customers in any zone).

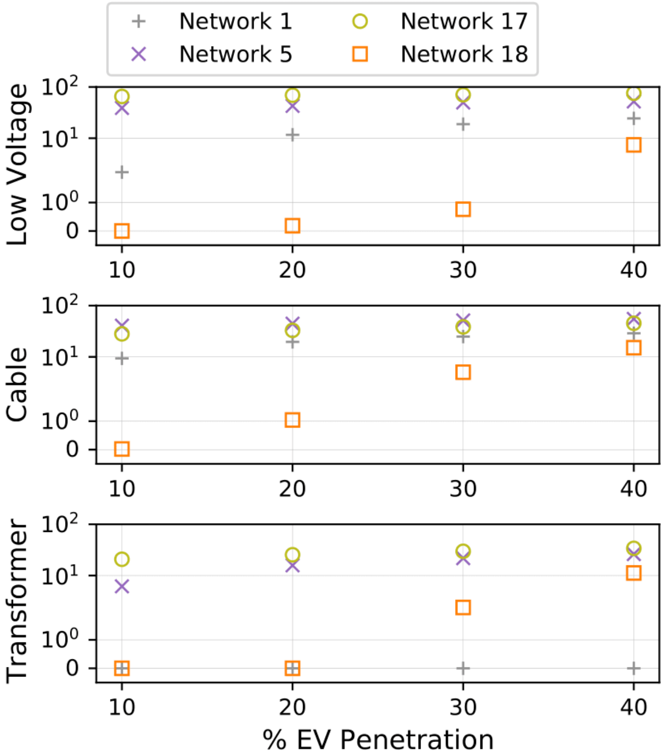

Figure 6-18: Low voltage, cable thermal, and transformer thermal violations (as a percentage of simulated timesteps) against EV penetration at 25% HP penetration.[71]

Figure 6-19 shows the frequency of low voltage violations (as a percentage of the 4,321 timesteps modelled) with number of customers per zone for four of the LV networks studied for 25% HP and 40% EV penetration with dumb EV charging. The figure shows that low voltage violations become more prevalent below 21 customers with the inclusion of dumb EV charging than in the HP only case shown in Figure 6-14. For four of the LV networks, low voltage violations are more frequent below 21 customers for 25% HPs with 40% EVs (see Figure 6-19) compared to 50% HPs and no EVs (see Figure 6-14). This is the case in all networks except *Network 10*, which is not included as it has no voltage issues at any HP or EV penetration due to having fewer than 8 customers in any zone.

[71] In each plot, the y-axis is a symmetric log scale which is linear between 0 and 1 (to allow values of zero and close to zero to be plotted)

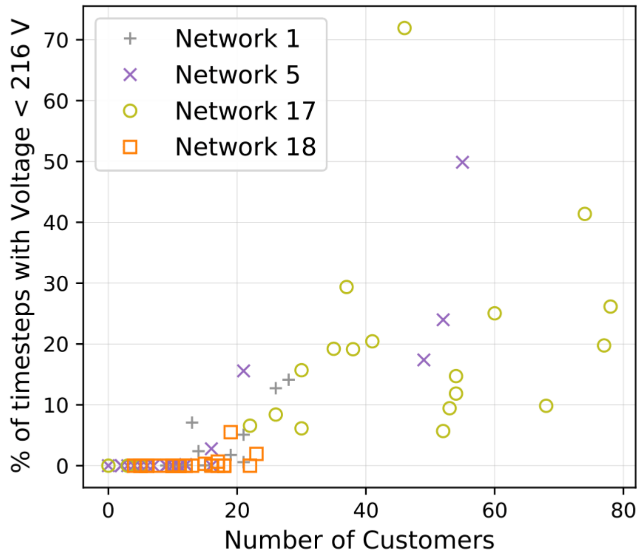

Figure 6-19: Low voltage violations (as a percentage of simulated timesteps) vs number of customers per zone for 25% HP and 40% EV penetration (dumb charging).

Figure 6-20 shows the frequency of cable thermal violations with number of customers per zone for 25% HP and 40% EV penetration with dumb charging. As with low voltage violations, cable thermal violations become more prevalent below 21 customers with the addition of EVs and in the case of 25% HPs and 40% EVs, overcurrent increases close to linearly with increasing number of customers, particularly steeply for *Network 1* from 13 customers.

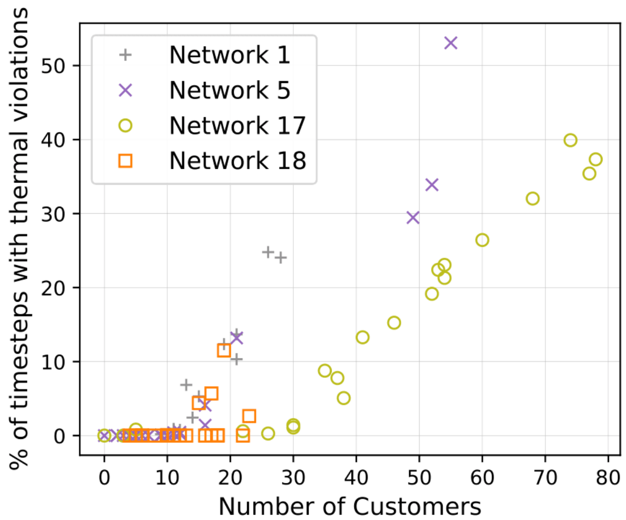

Figure 6-20: Cable thermal violations (as a percentage of simulated timesteps) vs number of customers per zone for 25% HP and 40% EV penetration (dumb charging).

6.3.2.2 Heat pump and dumb EV charging hosting capacity

The estimated hosting capacity for HPs and EVs with dumb charging is shown in Table 6-3. In the combined HP and dumb EV hosting capacity studies, HP penetrations above 50% were only modelled for *Network 10* as in the other networks the EV hosting capacity was below 15% at 50% HP penetration and there was little extra benefit to modelling up to 100% HP penetration.

Table 6-3: Hosting capacity for EVs with dumb charging at different HP penetrations with zero voltage violations, up to 0.5% cable and transformer thermal violations[1] (as a % of timesteps).

Network	**0% HP**	**25% HP**	**50% HP**	**75% HP**	**100% HP**	**Total**
Network 1	62 (31%)	43 (21.5%)	31 (15.5%)	n/a	n/a	200
Network 5	43 (12.8%)	25 (7.5%)	0 (0%)	n/a	n/a	335
Network 10	64 (100%)	64 (100%)	64 (100%)	64 (100%)	64 (100%)	64
Network 17	0 (0%)	0 (0%)	0 (0%)	n/a	n/a	883
Network 18	157 (47.9%)	152 (46.3%)	110 (33.5%)	n/a	n/a	328
Total	382 (21.1%)	284 (15.7%)	205 (11.3%)			1810

[1]It is assumed thermal violations are acceptable in <0.5% of timesteps without causing damage to cables and transformers, however, voltage violations are not tolerated due to the statutory minimum voltage of 216 V being a legal requirement.

The limiting factor in EV penetration in most cases is either cable current or transformer overloads. The EV hosting capacity of *Network 18* is severely limited by transformer overloads beyond 30% EV penetration at 25% HPs (see Figure 6-18) due to the large evening peak caused by dumb charging. *Network 18* was able to host a high percentage of HPs without EVs (68.9%), however it can only host 47.9% EVs without HPs. *Network 17* has transformer overloads with even 20% EV penetration at 0% HP penetration. Note 20% penetration in *Network 17* equates to 176 customers which is more than double the total number of customers in *Network 10*, hence why *Network 17* would need upgrading for even low HP and EV penetrations (and EV optimisation would not be able to change this significantly). The EV hosting capacity in *Network 17* will be between 0% and 10% for 0% HP penetration, however 0% is the best conservative estimate using increments of 10% EV penetration.

6.3.3 HP and CMS optimised EV capacity

The stages in estimating the HP and optimised EV hosting capacity, detailed in sections 5.5 and 5.5.2, are as follows: calculate zonal power flow limits; estimate headroom from the zonal power flow limits; assign HP and EV capacities based on the headroom; carry out EV optimisation, and finally validate the results. As these stages were carried out for multiple zones across the five LV networks studied, the results of the intermediate stages are presented for a single zone in *Network 1*, whereas the final hosting capacity results are presented for all networks.

6.3.3.1 Zonal power flow limit

The zonal power flow limit, P_z^{Vlim}, is calculated from the minimum power flow that resulted in a minimum voltage of 0.94 p.u. An example of the estimation of P_z^{Vlim} for *Network 1*, zone 11 is shown below in Figure 6-21, where P_z^{Vlim}=29.6 kVA. The points on Figure 6-21 correspond to the zonal minimum voltage and supply cable flow for 12,673 timesteps of each HP penetration case combined (from 0 to 100% HP penetration in increments of 25%). The 0.94 p.u limit is conservative and corresponds to a phase to neutral voltage of 225 V for the base voltage of 240 V used in these case studies. This is to allow a margin of error to prevent additional EV load from causing voltages to drop below 216 V (the UK statutory minimum voltage [210]) which corresponds to 0.94 p.u for a nominal voltage of 230 V.

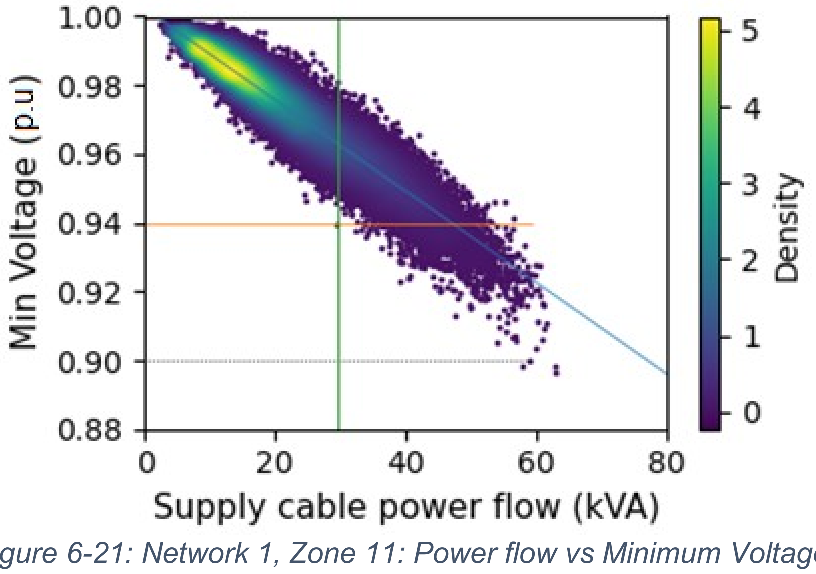

Figure 6-21: Network 1, Zone 11: Power flow vs Minimum Voltage.

Table 6-4 shows the voltage power flow limit. P_z^{Vlim}, for each zone in *Network 1*. The feeder head thermal limit, $P_{z,t}^{Tlim}$, is set by the feeder head line rating of 185 A (which is the same for all four feeders in network 1) converted to kVA. The feeder head thermal power flow limit, $P_{z,t}^{Tlim}$ varies by a small amount depending on the supply point voltage, which for *Network 1*, ranged from 0.974 p.u to 1 p.u in the cases modelled, resulting in values of $P_{z,t}^{Tlim}$ between 38.9 kVA and 40 kVA.

Table 6-4: Network 1: zonal voltage power flow limit, P_{z}^{Vlim}, kVA.

	Phase		
Feeder	1	2	3
1	29.6	23.9	31.5
2	23.2	20.8	25.9
3	17.1	25.4	18.1
4	21.1	21.6	17.1

The voltage power flow limits Table 6-4 are significantly lower than the values of $P_{z,t}^{Tlim}$, which suggests that *Network 1* is more limited by low voltage than by cable thermal limits with the addition of HP demand. This is true for all the LV networks studied in this thesis[72] which contrasts with the results of thermal and voltage violations with increasing HP penetration shown in Figure 6-15. The results in Figure 6-15 include thermal or voltage violations at any point in a zone, not just the feeder head, and show that voltage and thermal violations occur with similar frequency at a given HP penetration. In fact, for *Network 1* and *Network 5,* cable thermal violations are more frequent than low voltage.

The voltage power flow limit is lower than the thermal power flow limit as the method used in this thesis for setting a voltage power flow limit has high levels of uncertainty, and therefore is required to be more conservative. This is shown in Figure 6-21 where the zonal minimum voltage of 0.94 p.u. corresponds to supply cable power flows between 29.6 kVA and 56 kVA based on results for all HP penetrations and timesteps

[72] The only exception was in *Network 5* where 3 feeders had a supply cable rating of 71 A in the publicly available LVNS model [187]. As these cables were persistently overloaded (beyond 200 A) in the modelling results, it was assumed that the ratings were assigned in error, and they were subsequently increased to 240 A (based on comparable feeder head cable ratings).

modelled. To prevent voltage violations, the most conservative power flow limit of 29.6 kVA is used. On the other hand, the feeder head thermal limit varies only slightly with supply voltage and does not require such a conservative estimate. Therefore, although the headroom is most frequently limited by the voltage power flow limit using the methods in this thesis, it should be noted that high levels of HPs and EVs cause both voltage and thermal violations on the LV networks studied. In the results for HP and optimised EV capacity in section 6.3.4.1, a sensitivity analysis is provided on EV optimisation with a less conservative headroom to determine the effect on voltage and thermal violations to indicate whether the voltage power flow limit is overly conservative.

6.3.3.2 Headroom calculation

From (5-1) and (5-2), the headroom and footroom was calculated for each network, case, zone and timestep. The example of a P2 headroom profile for *Network 1*, zone 11 for HP penetrations between 0 and 100% is shown in Figure 6-22. In this figure it is clear that there are times when the headroom is positive which indicates ‘spare’ capacity in the zone, and also when it is negative, which indicates the possibility of voltage or current violations. It should be noted that these P2 headroom profiles are conservative as they are based on a 225 V low voltage threshold, however this safety margin is required to prevent voltages below the statutory limit of 216 V once EV demand is added.

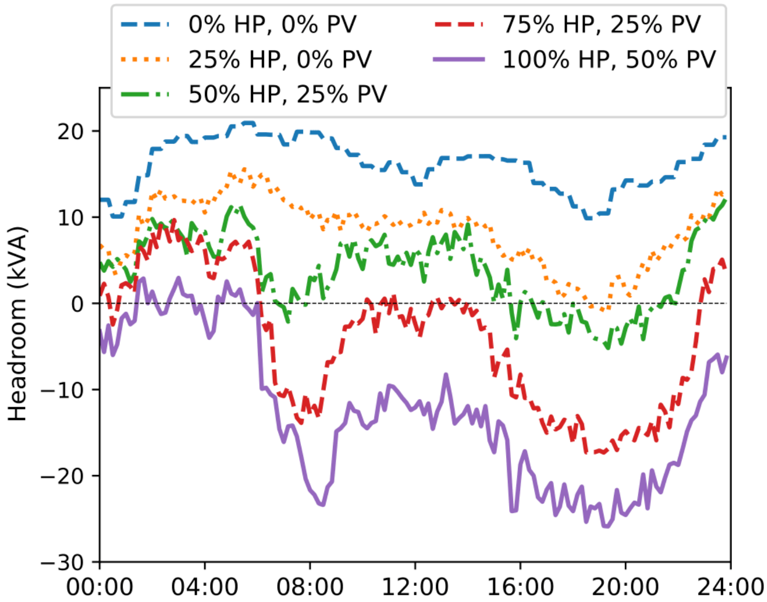

Figure 6-22: Network 1, Zone 11: P2 headroom for each HP penetration case.

Based on the P2 headroom profiles in Figure 6-22, 75% and 100% HP capacity could not be hosted in *Network 1*, zone 11 due to periods of highly negative P2 headroom indicating that there is a high probability of voltage and/or thermal violations.

6.3.3.3 HP and EV capacity estimation

Using the P2 headroom for all zones, achievable HP and EV hosting capacities are estimated per zone for each of the five case study networks. The HP hosting capacity is defined as the highest HP capacity with a net positive P2 headroom profile above a threshold of 120 kVAh over a 24 hour period[73]. For example, in the *Network 1*, zone 11 case (Figure 6-22), 50% HP penetration has a net positive P2 headroom of 91 kVAh which is below the defined 120 kVAh threshold. For 25% HP penetration, the sum of P2 headroom is 200 kVAh which is acceptable as it is above the 120 kVAh threshold. The EV hosting capacity is calculated from the total P2 headroom for the accepted HP capacity case. In the zone 11 example, the total daily P2 headroom for the 25% HP accepted case is converted to 196 kWh assuming a power factor of 0.98.

[73] This threshold has been determined empirically to ensure that P2 headroom profiles with periods of negative headroom have enough positive headroom capacity for a sufficient number of EVs (approximately 8 in this case) to both charge and provide enough V2G to prevent thermal and voltage violations caused by peak HP demand.

By dividing this sum of daily P2 headroom by the maximum daily EV charge calculated in section 0 (14.2 kWh/day), an initial estimate of 13 EVs is obtained.

By replicating this approach for all zones, a total HP hosting capacity of 30 HPs has been estimated for *Network 1* with an initial estimate of 124 EVs. However, the estimate of EV numbers does not reflect charging behaviour and therefore it must be refined using realistic EV travel diaries.

6.3.3.4 EV optimisation

To ensure EV charging demand is satisfied for a wide range of travel schedules and charging behaviour, EV optimisation is carried out for randomly sampled EV travel diaries using the zonal P2 headroom for assigned HP capacities, and an initial estimate of EV numbers. As described in section 5.5.2, the number of EVs is reduced until 10 consecutive successful optimisation results are achieved for a given number of EVs. This gives a more realistic estimate of the number of EVs that can be charged based on realistic travel diaries rather than being solely based on total headroom available. On this basis, for *Network 1* the total number of EVs that can be charged for a wide range of travel diaries, while respecting the P2 headroom limits, is revised to 88 (44% of customers).

An example of a successful optimisation result for *Network 1*, zone 14 is shown in Figure 6-23 for 9 EVs with a negative headroom period between 16:00 and 21:00. The figure shows the headroom being fully utilised for the times that the EVs are plugged in, with the EVs providing some V2G during the negative P2 headroom period which is limited by the footroom and the available headroom to replace the V2G energy provided. As a reminder, the negative headroom represents possible thermal or voltage violations in the LV network zone, and is provided by the DSO to the CMP (EV aggregator) as a signal to provide V2G to reduce the potential for these violations.

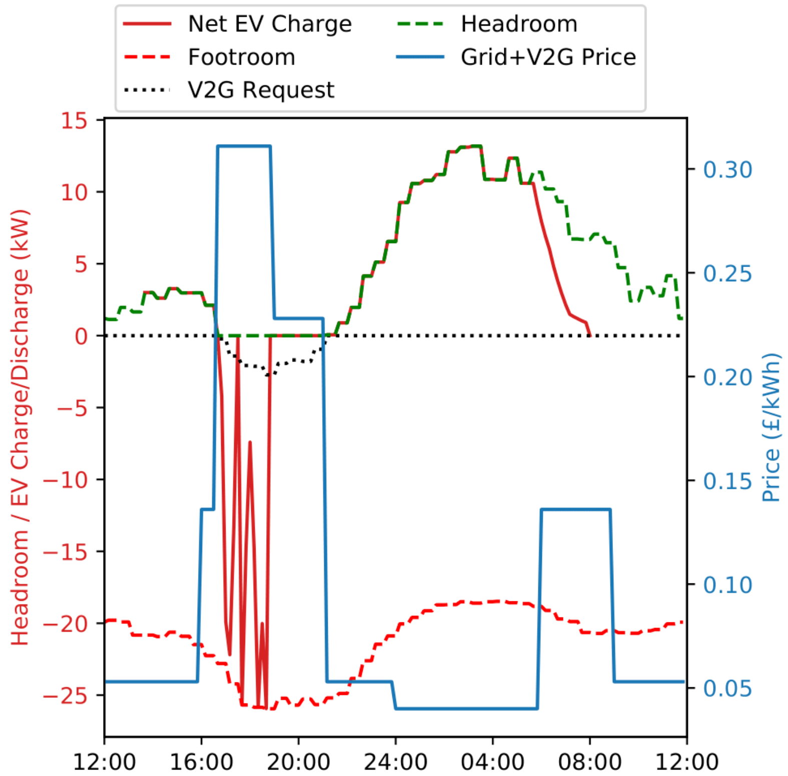

Figure 6-23: Network 1, Zone 14: Results of EV Optimisation Schedule (24 hrs).

In Figure 6-23, there is some V2G provided between 16:00 and 21:00, however not the full amount requested over the entire period of negative headroom. This is because there is no hard constraint on the optimisation to provide V2G at times of negative headroom, and instead, the price signal of an added 17.5 p/kWh for V2G (resulting in the increased 'Grid+V2G Price' in Figure 6-23) is relied upon to incentivise injection where the EV schedule and headroom allows.

The EV optimisation formulation used in this thesis is suboptimal in terms of V2G provision over negative headroom periods because without a hard constraint on providing the required V2G, the optimisation provides more than the required V2G in response to the price signal between 16:00 and 18:00, but there is insufficient headroom to provide any further V2G while still respecting the hard constraint of achieving the required final SoC for each EV. Put simply, there was too much V2G for the first half of the negative headroom period, and not enough for the other half, but the end result was the same V2G income for the CMP. Solutions to this problem could be capping the V2G injection, by setting the footroom to be equal to the negative headroom, or making the provision of V2G a hard constraint. Capping the V2G injection would prevent excess V2G being provided than is required to prevent voltage or thermal violations within a zone. This would in turn spread the available V2G out over periods of negative headroom rather than excess V2G being provided for half of the period as observed in Figure 6-23. However, capping the V2G would limit the wider potential to provide grid services to the DSO and TSO at peak pricing times. Making the V2G provision a hard constraint was explored, however this can result in making the optimisation problem infeasible: if there are insufficient EVs plugged in over the negative headroom period; or not enough headroom available over the remaining time they are plugged in to replace the energy provided as V2G.

Alternatives to modifying the EV optimisation formulation to provide more V2G include allowing fewer EVs to free up headroom, or relaxing the requirement to fully charge EVs. This is illustrated in Figure 6-24 where the number of EVs has been reduced to 6 and the final state of charge requirement has been relaxed to 97% of the SoC specified in the travel diary.

Figure 6-24 shows that the requested V2G is provided by the 6 EVs for the entire duration of the negative headroom period between 16:00 and 21:00. However, the EVs are providing more V2G than is needed which has used network capacity that could have been used to charge more cars.

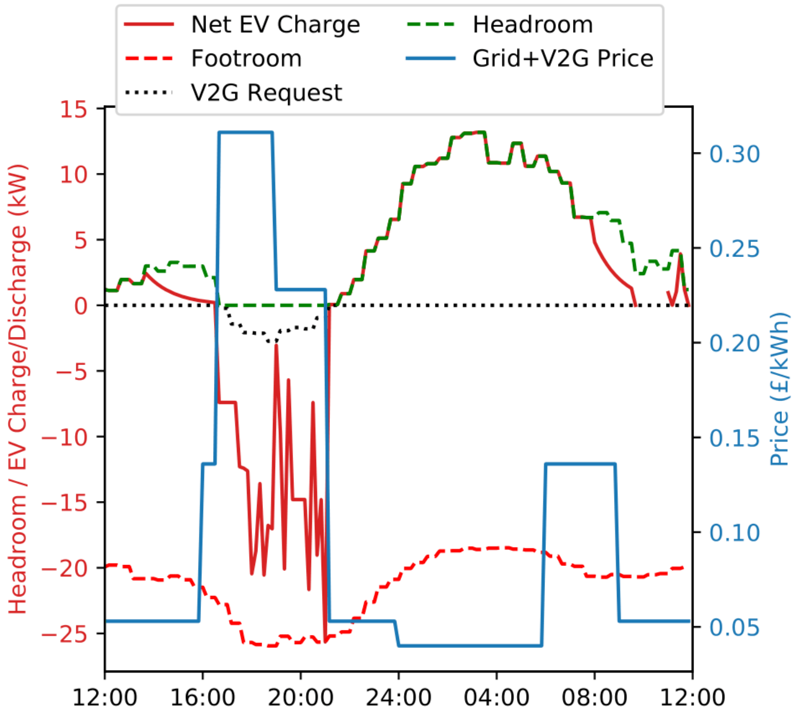

Figure 6-24: Network 1, Zone 14: Results of EV Optimisation Schedule for 6 EVs.

In implementing the CMS proposed in this thesis, the rules set by the DSO on providing V2G during negative headroom is an important factor. In constrained zones there is a trade-off between maximising the number of cars that can be charged and providing sufficient V2G to prevent thermal or voltage violations. Safe network operation will be the overriding priority, and if V2G is not able to reliably prevent violations, the number of EVs will be limited or network reinforcement will be required. Using the EV optimisation formulation proposed in this thesis, although in some cases V2G is not fully provided, for most cases the majority of requested V2G was provided. For example, in *Network 1*, for 33 HPs and 82 EVs, an average of 79.1% of V2G requested was provided per zone.

6.3.4 HP and CMS optimised EV hosting capacity validation

From the HP headroom assessment and EV optimisation, the total HP and EV hosting capacity has been estimated for each of the networks, summarised in Table 6-5. To ensure that these levels of HPs and EVs do not cause thermal or voltage violations, the optimised EV dispatch along with the assigned HP capacity has been validated for each network by carrying out load flow modelling for a subset of 'worst case' sample days. The sample days have been selected as those with the lowest total headroom per zone from the 88 days of winter 2013 modelled during the HP headroom analysis. For example, for *Network 1* which has 12 zones, the validation would be carried out for the days with the lowest total headroom in the 12 zones.

For a given zone, the EV optimisation is carried out using the same headroom profile each day, but with a different sample of EV travel diaries to capture a range of possible EV charging behaviour (and availability to provide V2G).

The validated HP and optimised EV hosting capacities, shown in Table 6-5, are significantly higher than for dumb EV charging (shown in Table 6-3) in three of the five networks assuming thermal violations in up to 0.5% of timesteps are tolerable[74]. The number of transformer thermal violations is zero for all networks except *Network 5* which has violations in 0.5% of timesteps.

[74] It is assumed thermal violations are acceptable in <0.5% of timesteps without causing damage to cables and transformers, however, voltage violations are not tolerated due to the statutory minimum voltage of 216 V being a legal requirement.

Table 6-5: Summary of HP and CMS optimised EV hosting capacity.

Network	HPs	EVs	Current Violations[1]	Voltage Violations[1]	V2G Delivered
Network 1	30 (15%)	88 (44.0%)	0	0	79.1
Network 5	88 (26.3%)	110 (32.8%)	0.3	0	81.9
Network 10	64 (100%)	64 (100%)	0.1	0	n/a
Network 17	8 (0.9%)	41 (4.6%)	0.3	0	75.8
Network 18	190 (57.1%)	235 (71.6%)	0.3	0	78
Total	380 (21.0%)	538 (29.7%)			

[1]Violations are in % of timesteps modelled

In total, for the five networks studied, it was possible to host 21% HP and 29.7% EV penetrations without the requirement for additional network upgrades. The total EV hosting capacity is close to double the 15.7% EV penetration that was possible with dumb charging with 25% HPs. In the case of *Network 17*, which has 883 of the 1810 customers in the five networks studied, there was simply not enough headroom to host a significant penetration of HPs or EVs (beyond 4.6%). In networks with such high number of customers per zone and many customers, network upgrades will be required to host significant penetrations of HPs and EVs and EV optimisation can only provide very limited gains.

The biggest gains from the CMS EV optimisation came in *Network 18*, which was limited to 33.5% EV penetration at 50% HP capacity for dumb charging. Using the LV CMS, it was possible to increase EV and HP penetrations to 71.6% and 57.1% respectively. The method was also successful in facilitating EV hosting capacities 1.4 times and 2.6 times higher in networks 1 and 5 respectively compared to the dumb charging case with 0% HPs. These EV capacities were realised with HP penetrations of 15% and 26.3% in networks 1 and 5, respectively. The levels of V2G delivered were above 75% of requested output for networks 1,5 and 18 which, in the case of several zones, allowed higher HP penetrations by injecting power at times with negative headroom where HP demand could otherwise have caused current or voltage violations.

6.3.4.1 Sensitivity study: modified headroom

A sensitivity case is presented to demonstrate the potential for tuning the headroom calculation and the effect this has on violations and HP and EV numbers. Table 6-6 shows the HP and EV hosting capacity results when the 5th percentile (P5) headroom is used rather than the P2 headroom.

Table 6-6: Summary of HP and optimised EV hosting capacity: P5 headroom.

Network	HPs	EVs	Current Violations[1]	Voltage Violations[1]	Transformer Violations[1]
Network 1	38 (19.0%)	95 (47.5%)	0%	0%	0%
Network 5	99 (29.6%)	117 (34.9%)	0.60%	0%	1.6%
Network 10	64 (100.0%)	64 (100.0%)	0.10%	0%	0%
Network 17	8 (0.9%)	83 (9.4%)	1.20%	0.20%	0%
Network 18	200 (61%)	242 (73.8%)	0.10%	0%	0.10%
Total	409 (22.6%)	601 (33.2%)			

[1]Violations are in % of timesteps modelled

By modifying the percentile in LV CMS to be less conservative in the headroom estimate, it was possible to slightly increase the total HP penetration to 22.6% (an increase of 1.6%) but at the expense of voltage violations of up to 0.2%, transformer violations of up to 1.6% and cable current violations up to 1.2% (in terms of % of timesteps modelled in each case). The headroom available for EV optimisation was higher than the base case and the number of EVs increased by 63 (3.4%) across all networks. These results demonstrate some flexibility in the method for prioritising between maximising HP and EV capacity and minimising voltage and thermal violations. The voltage, thermal and transformer violations could be reduced by further tuning of the headroom calculation.

6.3.4.2 EV optimisation and transformer power flow

The optimisation of EVs has the potential to have a significant impact on the power flows to and from LV secondary substations. In Figure 6-25 the maximum transformer power flow per 10 minute timestep is shown for *Network 18* based on the results of all three cases considered: HP only, HP and dumb EV, and HP and optimised EV.

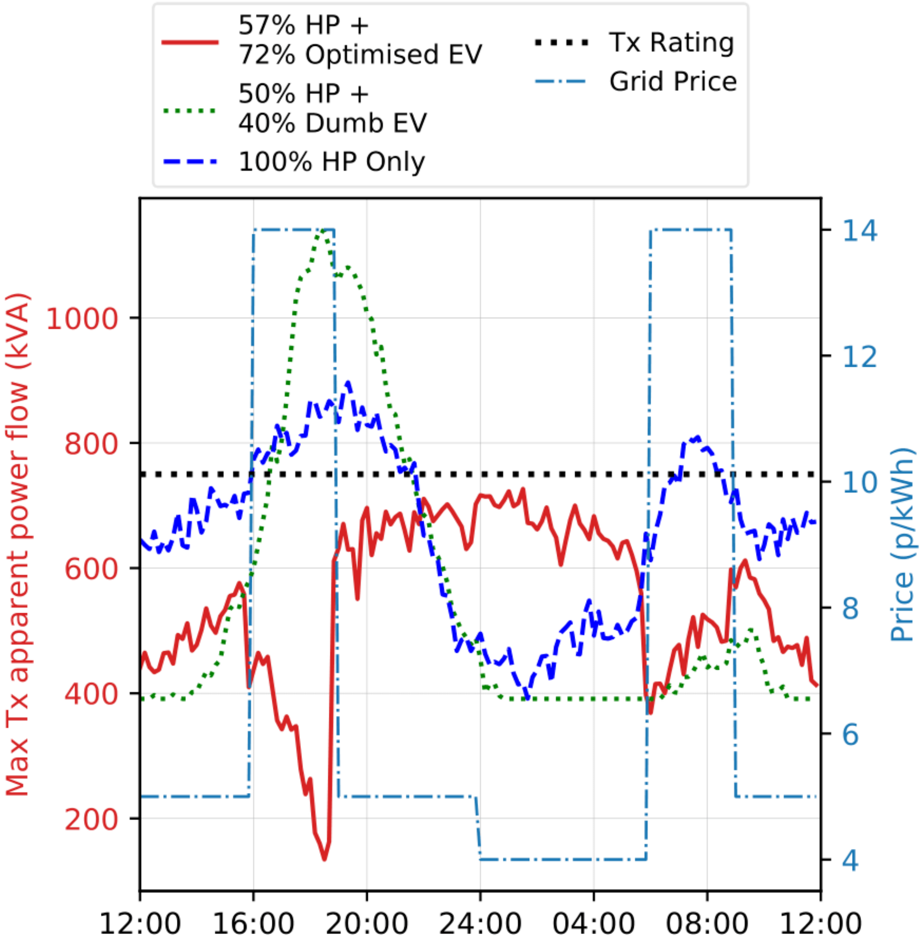

Figure 6-25: Network 18 maximum transformer flow for optimised EV charging, Dumb EV charging and HP only cases.

Although the penetrations of HP and EV for the cases in Figure 6-25 are different, it is still useful to compare the timings of peak power flows for each case. The 'HP + Optimised EV' line in Figure 6-25 is for the maximum HP and EV hosting capacity of *Network 18* with the applied LV CMS: 57% HPs and 72% EVs. In this case, the transformer power flow is maintained within its limit (depicted in Figure 6-25 as 'Tx rating') using the EV optimisation and CMS zonal headroom limits. The 'HP + Dumb EV' line is for the nearest modelled HP and dumb EV capacity to the maximum capacity in the LV CMS: 50% HPs and 40% EVs. For a 7% lower penetration of HPs and a 32% lower penetration of EVs than the maximum capacity in the LV CMS, the transformer is at times heavily overloaded due to the evening peak of dumb EV charging when EVs are most likely to plug in to charge. Finally, the 'HP Only' line is included to compare the transformer power flow for 100% HPs and no EVs. In this case the transformer can be overloaded in the evening and morning peak HP demand, and it is worth noting that using the EV optimisation and V2G in the ‘HP and optimised EV’ case can significantly reduce the transformer peak power flows caused by the HP demand.

The EV optimisation is very effective at reducing the peak power flows at the times of the highest DUoS price which is the majority component of the ‘Grid price’ in Figure 6-25. For the optimised EV case there is a rapid increase in EV demand after 19:00 and after 09:00 when the DUoS price drops and EV charging increases. The DUoS price signal used in this case study could be improved by extending the high price DUoS charge till after the HP peak subsides at 22:00. The example in Figure 6-25 highlights the importance in choosing the right price signals and limits for EV optimisation. In the ‘HP and Optimised EV’ case, the headroom limit successfully prevented the post 19:00 and 09:00 spikes in EV charging from causing transformer limits from being exceeded. Using price signals alone, EV optimised dispatch could cause network stress events including violation of voltage, line current and thermal limits, especially when multiple EVs across multiple zones and networks are responding to the same price signals.

6.3.4.3 Computation times

The major advantages of the proposed headroom optimisation method when compared to 3-phase multi-period OPF are that network modelling and EV optimisation activities are separated which opens up opportunities for parallelisation, and that computational times can potentially be vastly reduced. For example, the average time taken to optimise a day's EV dispatch at 10-minutely resolution (144 timesteps) for a zone in *Network 18* with an average of 10 EVs is 2.7 s using a 3.3 GHz i5 processor with 8 GB RAM. By optimising zones in parallel (using multiple processors), a day's EV scheduling for 242 EVs in *Network 18* across 662 nodes in 27 zones, was carried out in under 20s using a quad core processor. For comparison, using the same 3.3 GHz processor, it took 2 hours to optimise a day's dispatch of 80 EVs at 30-minutely resolution (48 timesteps) by carrying out 3-phase multi-period OPF on the IEEE 13 node test network using the PICOS solver [211] in the OPEN platform [212]. The 3-phase power flow model in OPEN is linear, giving an approximate solution, and the 2 hour computational time is with voltage constraints relaxed. With increasing network size, multi-period OPF can become intractable: for example, for an LV network with 163 nodes and 15 EVs, using the same 3.3 GHz processor as in the previous examples, it was found that for many EV and demand configurations, the optimisation of a day's EV dispatch does not converge (after iterating for several hours) at 10-minutely resolution for single-phase multi-period OPF using the Ipopt [166] non-linear solver within the OATS platform [165].

When considering multiple LV networks which number into the tens of thousands on a regional level, the LV CMS proposed in this thesis could offer significant improvement in tractability compared to 3-phase multi-period OPF. The offline headroom calculation requires more computational effort depending on the number of timesteps analysed, therefore generalised headroom profiles could be developed based on parameters such as number of customers, feeder head line rating or electrical distance rather than calculating a headroom profile afresh for every zone in every network.

6.4 Chapter summary

In this chapter, a novel and tractable LV congestion management scheme (CMS) has been applied to maximising the hosting capacity of LV networks for HPs and optimised EVs on five representative LV networks. The LV CMS has been shown to offer the following key improvements on existing LV congestion management solutions in the literature:

- Separation of network modelling activities by the DSO and EV optimisation by a third party such as an aggregator.
- Significantly reduced computational times particularly for multi-period scheduling of EVs.
- Improved tractability by allowing a large complex optimisation problem to be separated into multiple sub-problems which can be solved in parallel.
- The potential to significantly increase LV network hosting capacity without the need for network reinforcement.

The LV networks had number of customers ranging from 64 to 883 and the number of customers per zone, defined as a unique combination of feeder and phase, was seen to be an important parameter in assessing the capacity for HPs. Beyond 21 customers per zone, thermal and voltage violations are much more prevalent, and HP and EV hosting capacity will be limited without network reinforcement.

Hosting capacities for dumb EV charging at differing HP penetrations were estimated based on charge profiles created from realistic travel diaries for 7 kW chargers and EVs with battery sizes ranging from 24 kWh to 75 kWh. For the networks considered, the smallest network, with a maximum of 8 customers per zone and 64 customers, could host up to 100% HPs and 100% EVs with ‘dumb' charging. This network would not be classed as congested and would not require the implementation of a LV CMS. The largest network with a median of 48 customers per zone and 883 customers was highly congested and had insufficient headroom to host more than 4.6% EVs even with optimised charging and 0.9% HP penetration. These networks provided 2 extremes in terms of number of customers: the LV CMS was either unnecessary or unable to enable significant HP and EV penetrations.

The real value in the LV CMS was seen in the three networks with 200, 325 and 328 customers. In these cases, EV hosting capacity was more than doubled compared to dumb charging with comparable HP capacities and could enable between 15% - 57% HPs and 33% - 72% optimised EVs without the need for additional reinforcement. These networks had a median number of customers of between 9.5 and 14.5 per zone and have sufficient headroom for EV optimisation to provide significant benefit in terms of smoothing HP peak demand and maximising EV hosting capacity.

The LV CMS methodology applied in this thesis is conservative in that a ‘worst case' headroom is used and applied to all days; in future work this could be enhanced by the use of a day-ahead forecasted headroom linked to temperature for example. The optimisation of EVs during the summer could also be studied using the same methodology and alternative travel diaries could be included to reflect changing travel habits such as increased home working. Finally, an important development of the headroom methodology would be in producing generalised headroom profiles linked to key network parameters to save re-calculating the headroom for every zone.

In this chapter, the LV CMS was applied to managing LV network congestion, however LV assets such as EVs could provide valuable flexibility to the DSO at higher voltages, and to the TSO. To facilitate this, in the next chapter the LV CMS is integrated with the *Local market* DSO-TSO coordination mechanism. By combining these tools, it is aimed to provide a mechanism for flexibility from LV assets to be aggregated up to the GW scale for use by the TSO while still respecting LV network constraints.

Chapter 7:

LV/MV/HV Congestion Management

The main objective of this thesis is to determine how distributed flexibility can be coordinated between the DSO and TSO using methodologies that can be scaled to millions of flexibility providers down to LV level. To do this requires a combination of the *Local market* (chapter 3) to carry out DSO-TSO coordination at MV/HV and the LV CMS (chapter 5) to manage flexibility at LV. In this chapter, the integration of the *Local market* and LV CMS is investigated, with flexibility from LV assets (EVs in this case) made accessible to the DSO and TSO at all voltage levels. The high level market operation of the combined LV CMS and *Local market* operation is firstly outlined. The combined LV CMS and the *Local market* operation is then demonstrated for a single settlement period (SP) using a suitable LV and MV/HV network combination from previous chapters. Finally, the flexibility available from EV charging and V2G in the LV CMS is considered over a 24 hour period to consider the influence of EV charging behaviour and the available network headroom.

7.1 High level market operation

The *Local market* DSO-TSO coordination scheme provides a mechanism for distribution system congestion management down to MV (11 kV). In this configuration it would take place after 'gate closure' of the DSO market (as illustrated in Figure 3-1). The LV CMS provides a tractable mechanism, to allow an aggregator to optimise flexibility from the home charging of EVs within three-phase voltage and current limits. The management of flexibility in the LV CMS is proposed to be contracted to congestion management providers (CMPs). It is assumed that the CMPs can also optimise the flexibility of EVs in wholesale and ancillary service markets at day ahead and intraday timescales. To make flexibility from home charging of EVs at LV available to the DSO and TSO, it is proposed that the CMP also participates in the *Local market* as depicted in Figure 7-1. The figure shows the integration of the LV CMS and *Local* *market* with the CMP providing aggregated positions of their assets, and bids and offers of available flexibility, to the DSO congestion market at gate closure. The CMP must also act on redispatch instructions by the DSO or TSO if activated in the *Local market*.

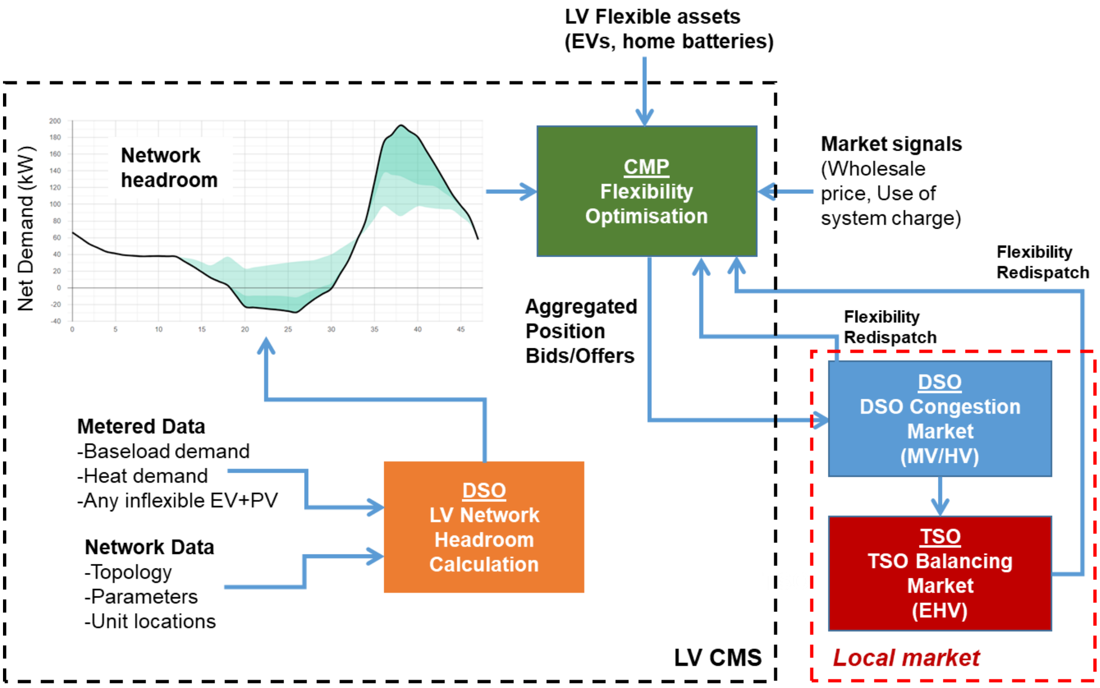

Figure 7-1 Combined LV CMS and Local market operation.

The steps of integrating the LV CMS and *Local market* for are summarised as follows:

1. The CMP calculates bids and offers for EV flexibility[75] ahead of DSO market gate closure. These bids/offers would be dependent on the CMP's own market strategy. This thesis provides an example bid/offer calculation based on the associated cost of adjusting EV net charge (charge - discharge).
2. The LV CMP then passes the maximum and minimum net EV charge and bid/offer costs to the *Local market* scheme at DSO market gate closure.
3. The *Local market* DSO-TSO coordination mechanism operates. Redispatch instructions from the DSO or TSO are passed back to the CMP and the CMP responds by adjusting the net EV demand of their portfolio in real-time.

[75] The available EV flexibility can be calculated on a rolling horizon using continuously updated EV schedules and market signals.

The remainder of this chapter focuses on an example of a CMP bid and offer calculation of EV flexibility in LV *Network 18*, integrated with *Local market* operation of the Cornwall network. The aggregated flexibility available from *Network 18* is considered over a 24 hour period. In *Network 18*, there are 27 zones (unique combinations of feeder/phase) which are assumed to be contracted to the same CMP. EV flexibility can therefore be aggregated from all zones and assigned to a single secondary substation node connecting *Network 18* to the Cornwall network in the *Local market.* To consider a future scenario of the electrification of heat and transport, the maximum levels of HPs and optimised EVs calculated in the LV CMS case study in section 6.3.3 have been assigned to *Network 18*. The numbers of HPs and EVs assigned to *Network 18* are 190 and 235 respectively out of 328 connected households.

7.2 LV CMS bid and offer calculation

In this section, an example CMP bid/offer calculation is presented for a single SP to demonstrate the integration of the LV CMS and the *Local market*. The bids and offers in this case quantify the flexibility available from home charging of EVs by the CMP, along with the costs for providing this flexibility. These are passed to the *Local market* to allow the DSO and TSO to access the available flexibility as depicted in Figure 7-1. In the following bid/offer calculation, the CMP optimises the EV schedule with the EV net charge fixed at the maximum and minimum possible values for a given SP. The EV charging optimisation formulation used previously (see section 5.4) is applied, where the distribution use of system (DUoS) is the main component of the EV charging price. This results in the minimisation of EV charging and maximisation of V2G during high DUoS price periods in the morning and evening.

SP37 (18:00-18:30) is considered for *Network 18* (introduced in Figure 6-6) using the LV CMS case study input data from section 6.2 for the 12$^{th\ of}$ December 2013. The EV optimisation is carried out midday to midday[76], however this could be done on a rolling time-horizon or day-ahead/intraday depending on the CMP's optimisation strategy. The maximum and minimum net charge at a given timestep are constrained by the headroom and footroom limits determined using the LV CMS. These limits are in place

[76] Results in the following sub sections are presented from 17:30 to 24:00 to focus on the net EV charge for SP37.

to prevent actions by the CMP causing thermal and voltage violations in the LV network.

7.2.1 Maximum net EV charge schedule

The EV charging schedules for providing minimum and maximum net demand in SP37 have been calculated for each zone in *Network 18.* Figure 7-2 provides an example of the schedule for all EVs within zone 27[77] to provide maximum net demand during SP37 (see line labelled as 'Net EV Charge'). The figure shows that the maximum net EV demand available to the *Local market* for this zone during SP37 is the upper headroom limit of around 10 kW.

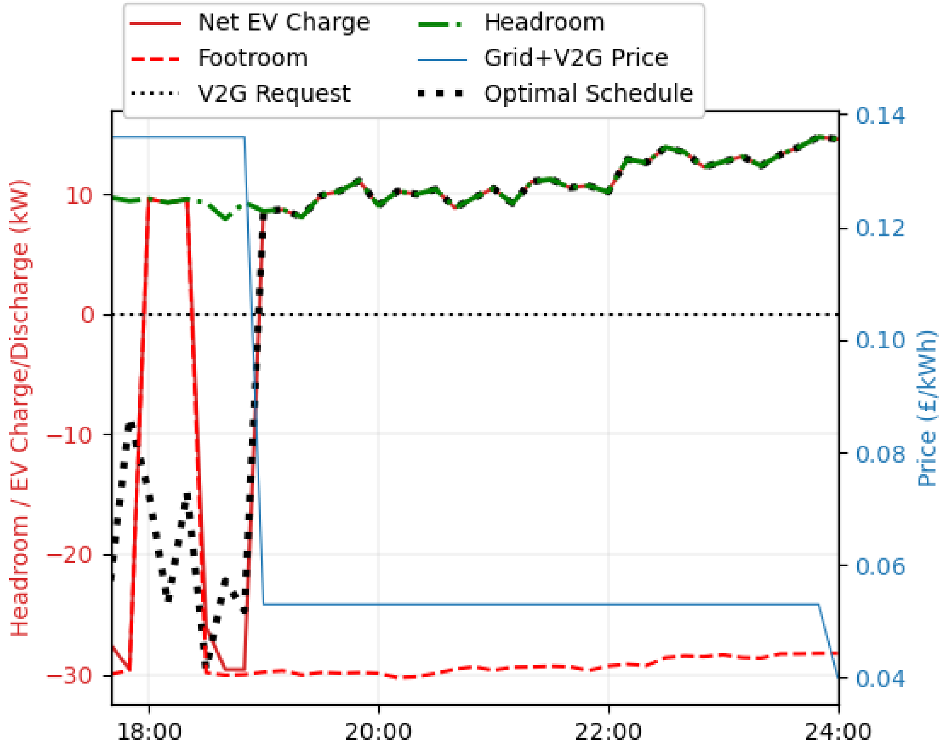

Figure 7-2: EV optimisation schedule for providing maximum EV charge for SP37 for zone 27 in Network 18 (evening of 12th December 2013).

The 'Optimal Schedule' dotted line shown in Figure 7-2 is the optimal result of EV scheduling without fixing the net demand in SP37. As shown in the figure, the optimal result is to inject power from 18:00 to 19:00 during high DUoS evening price period (see price on right hand axis). By fixing the net demand at 10 kW during SP37, the

[77] A zone is defined as a combination of feeder and phase, as detailed in Figure 5-2.

income for the CMP from V2G is reduced, and this lost revenue will be factored in to the bid price provided by the CMP to the *Local market*. The net EV demand is the same as the optimal schedule from 7pm onwards during which time the EVs charge at the maximum possible demand within the available headroom.

During periods of peak demand, V2G (power injection by EVs) can be requested under the LV CMS, which is represented by a negative headroom. In this case, the maximum net EV demand that can be offered by the CMP to the *Local market* is capped at the negative headroom capacity set by the LV CMS. For example, in zone 22 during the same SP, the maximum allowable net EV charge level is capped to -7.5 kW by the negative headroom set under the LV CMS. This is shown in Figure 7-3 and it illustrates the prioritisation of EV flexibility to the LV CMS to maintain LV thermal and voltage limits ahead of any requirement by the DSO or the TSO in the *Local market*.

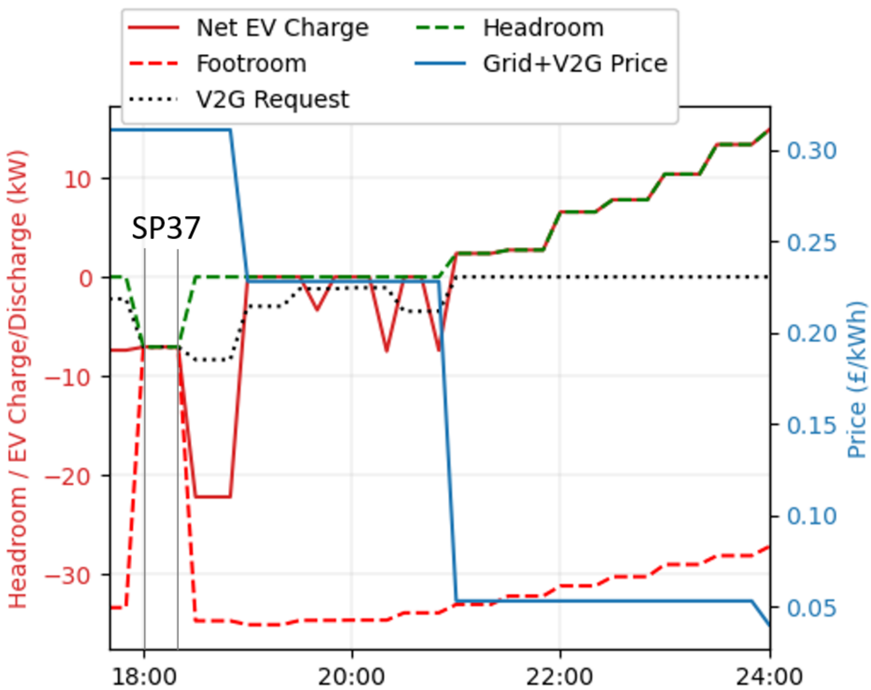

Figure 7-3: EV optimisation schedule for providing maximum EV charge for SP37 for zone 22 in Network 18 (evening of 12th December 2013).

Providing the maximum EV charge during SP37 across *Network 18* has the effect of reducing the minimum voltage in each zone. The resulting minimum voltages for all zones are shown in Figure 7-4 where a dip in minimum voltage is observed in most cases during SP37. However, it is noted that the minimum voltages are kept well above the statutory limit of 0.9 p.u[78] by the headroom set using the LV CMS. This is relatively low during SP37 due to the evening peak in baseload and HP demand.

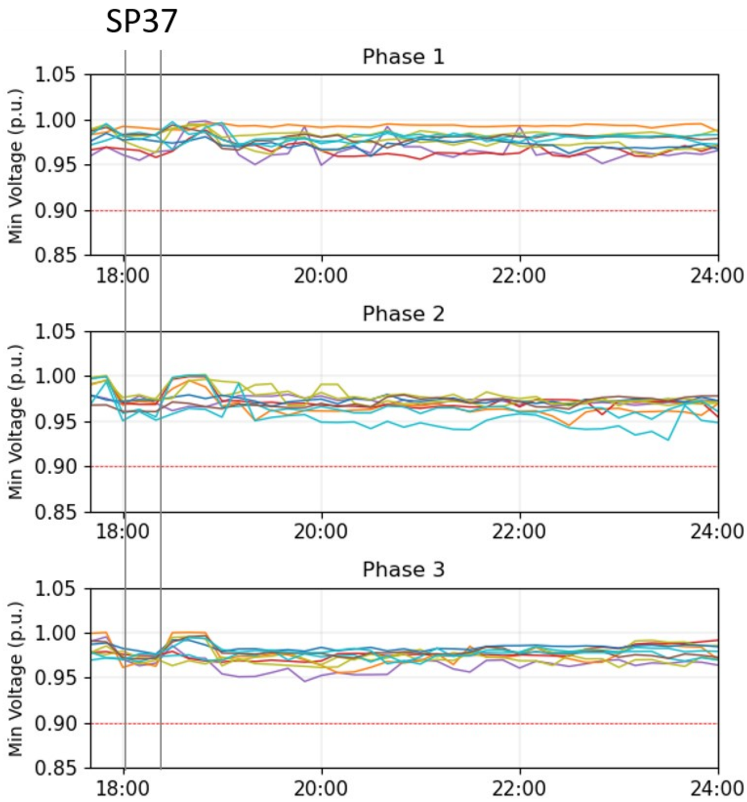

Figure 7-4: Minimum voltage in all Network 18 zones for maximum EV net demand in SP37 (evening of 12th December 2013). Each line represents a unique zone.

7.2.2 Minimum net EV charge schedule

To determine the minimum EV demand available to the *Local market*, the net EV demand is set at the footroom limit.

Figure 7-5 shows the optimised EV schedule of all EVs in zone 13 for minimum net EV demand during SP37. The figure shows that the minimum net demand during SP37 for this zone is around 30 kW meaning the EVs can provide up to 30 kW of V2G without causing thermal or voltage violations.

Across most zones in *Network 18,* there is generally more footroom available for EV V2G than headroom for EV charging during the evening when headroom is at its

[78] 0.9 p.u corresponds to the GB LV minimum voltage statutory limit of 216 V [209] for the 240 V base used at LV in this thesis.

lowest due to peak HP and baseload demand. At these times, V2G can provide a benefit to the LV network in raising the minimum voltage and reducing cable and transformer thermal loading. However, as long as the headroom limits are respected, the DSO or TSO can also increase the net EV charge without causing violations.

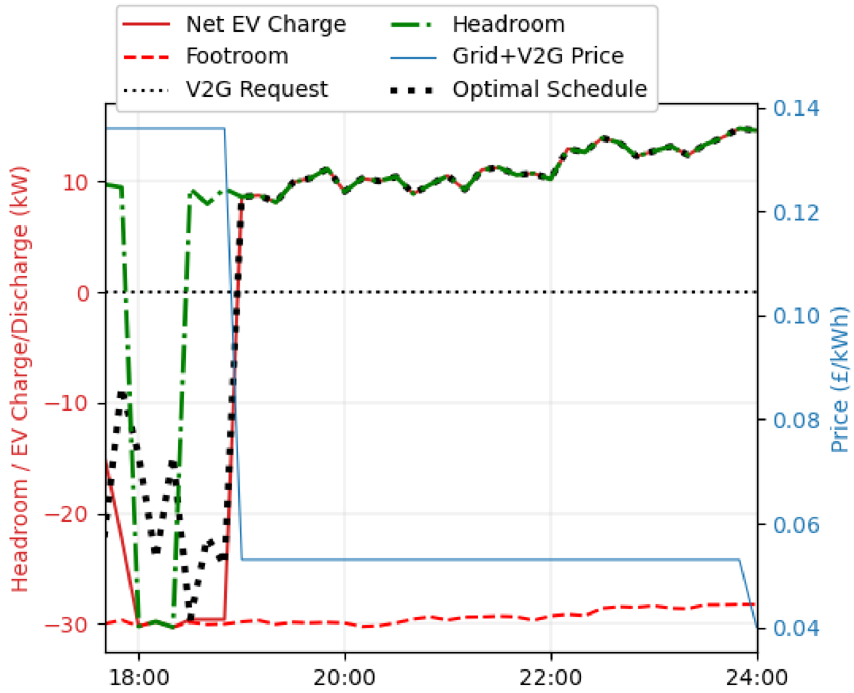

Figure 7-5: EV optimisation schedule for providing minimum EV charge for SP37 for zone 13 in Network 18 (evening of 12th December 2013).

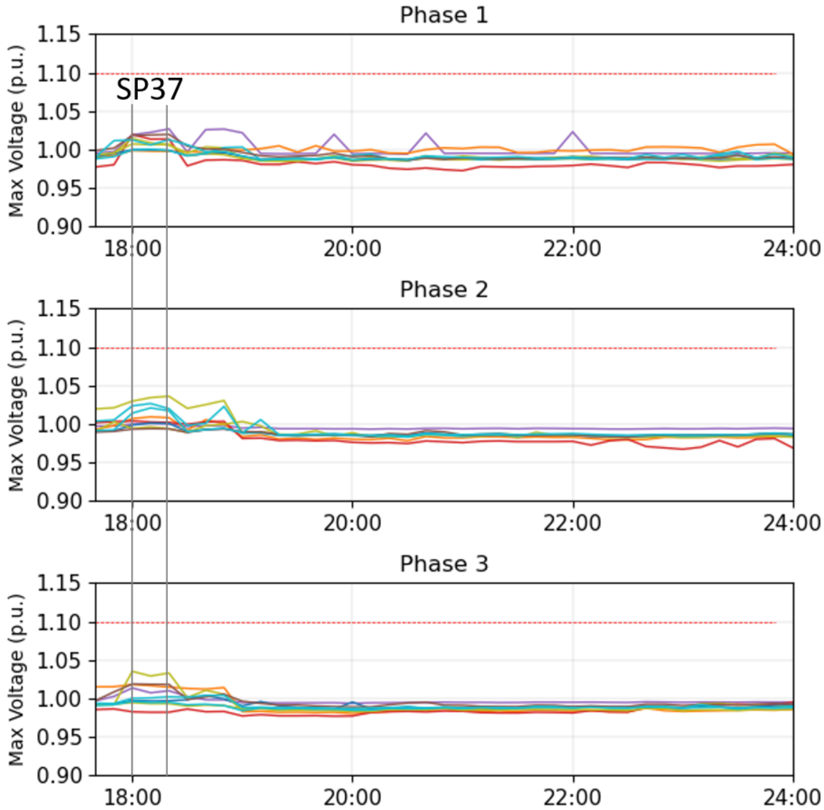

Figure 7-6: Maximum voltage in all Network 18 zones for maximum EV net demand in SP37 (evening of 12th December 2013). Each line represents a unique feeder.

Figure 7-6 shows the resulting maximum voltages for minimum EV net demand (maximum V2G) during SP37. A rise in voltage is observed during SP37, however, the footroom limit, set by the DSO in the LV CMS, prevents the voltage exceeding statutory limits of 1.05 p.u[79].

7.2.3 Aggregated net EV demand and transformer power flow

Assuming the same CMP is managing all the zones in *Network 18*, the net demand of all zones can be provided to the *Local market* as a single aggregated bid/offer for SP37. The bid is for an increase in demand (equivalent to a decrease in generation) and the offer is for a decrease in demand (equivalent to an increase in generation). The aggregated net EV demand across all *Network 18* zones, when optimised for maximum and minimum net EV demand in SP37, is shown along with the optimal

[79] 1.05 p.u corresponds to the GB LV maximum voltage statutory limit of 253 V (1.1 p.u. for a 230 V nominal voltage) for the 240 V base used in this thesis.

result in Figure 7-7. The optimal result is the schedule determined by the EV optimisation without fixing the EV charging demand to be the minimum or maximum values at any time. In SP37, the CMP for *Network 18* can offer the *Local market* a maximum of 47 kW net EV demand, a minimum of -506 kW net demand (corresponding to 506 kW V2G injection) with an optimal set point of -263 kW. The schedule for the remaining SPs remains reasonably close the optimum schedule for the remaining time periods. However, the entire 24h optimisation horizon is not shown and any adjustment to the EV schedule during SP37 from the optimum must be made up from other settlement periods. The final case study of this chapter on EV flexibility over 24 hours considers how dispatching flexibility at one time of day affects the available flexibility for other SPs,

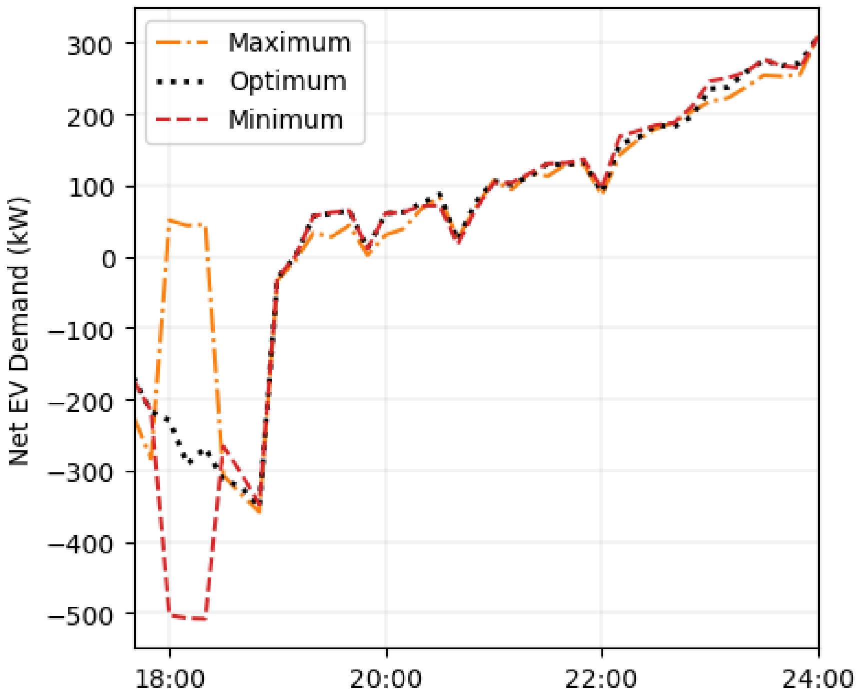

Figure 7-7: Aggregated Network 18 EV dispatch for maximum , optimum, and minimum net EV demand during SP37 (evening of 12th December 2013).

The optimal position of the CMP is to inject power during evening peak from 16:00 to 19:00 as this corresponds to the 'red zone' DUoS period[80] in the EV optimisation

[80] The DUoS charges, introduced in section 5.4.2 are charged by the DNO to customers for the utilisation of the distribution networks and include a 'red zone' period which corresponds to evening peak electricity demand.

formulation (see section 5.4.2). During the red zone period the price is more than twice as high as other times of day (see Figure 5-6) and it is assumed that the CMP is paid for injecting power during at these times. Although the DSO will not generally seek an increase in demand during the evening peak, there is flexibility available in the EV charging schedules to allow increased demand in *Network 18* by 310 kW during SP37 while respecting thermal and voltage limits (represented by the zonal headroom limits).

While the CMP is responsible for providing the positions of the EVs to the *Local market*, the DSO must also have an aggregated estimate of baseload demand. Both must be aggregated to the secondary substation as this is the interface between the LV CMS and the *Local market.* Figure 7-8 contains an example of the *Network 18* secondary substation power flow (equivalent to *Network 18* net demand) for the following cases: minimum, maximum and optimum SP37 power flow with 190 HPs and 235 EVs; and the 'No EVs' case is for 190 HPs and no EV demand.

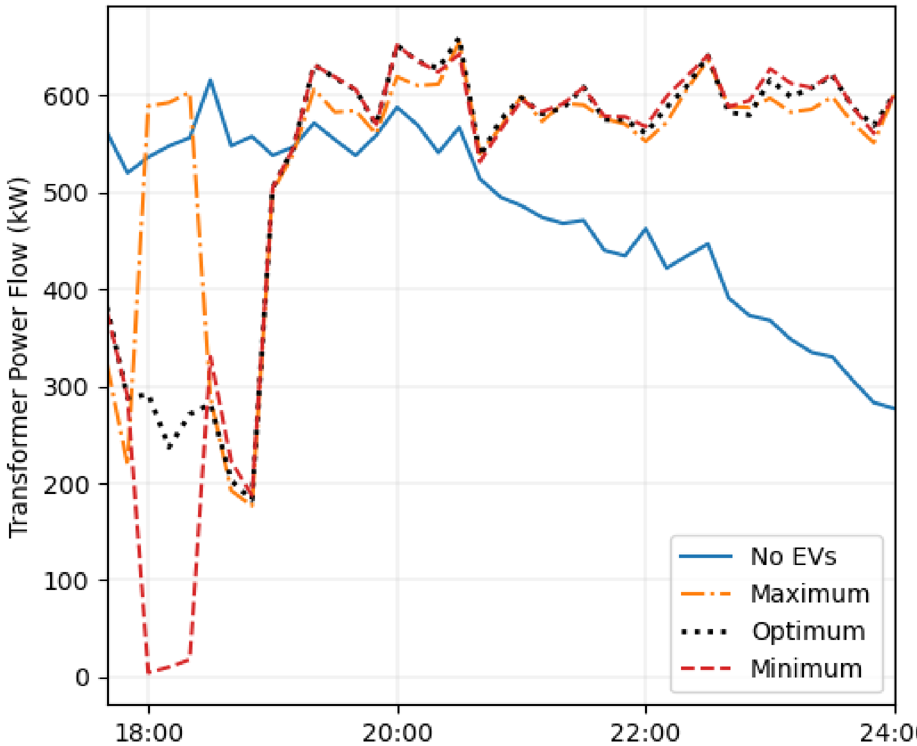

Figure 7-8: Aggregated Network 18 transformer power flow for no EVs, along with maximum, optimum, and minimum net EV demand during SP37.

In the *Local market*, the DSO requires an estimate of the *Network 18* demand at gate closure of the DSO congestion market which is assumed to be 2 hours ahead of delivery in this thesis. The net demand excludes that managed by the CMP (or CMPs) aggregated to the MV node. In this case, assuming all EVs are managed by the CMP, the DSO would use the 'No EVs' demand from Figure 7-8 in the *Local market* MV/HV network model while the CMP would provide the net EV demand positions from Figure 7-7. The effect of EV charging demand on power flow to/from *Network 18* is significant in Figure 7-8. By changing the EV charging schedule, the *Network 18* import power flow can swing from 600 kW import to almost 0 kW import during a period of peak evening demand. For networks with high levels of EVs, if these power flow swings of this magnitude are allowed to occur in response to price signals, without any network limitations, there will be a high risk of voltage or thermal violations. This highlights the importance of providing network signals, such as the headroom and footroom limits proposed in the LV CMS, to aggregators of LV assets to maximise the value from flexibility without causing network violations.

7.2.4 Bid and offer cost calculation

To participate in the *Local market* DSO-TSO coordination mechanism, the CMP must provide bid and offer costs to the DSO and TSO markets for adjusting the EV demand for a given SP. To demonstrate the integration of the LV CMS and the *Local Market,* an example methodology is provided for the CMP to calculate bid/offer costs based on the cost difference to provide the aggregated minimum and maximum net EV charging demands estimated in section 7.2.3. The EV charging costs are determined as a result of the EV optimisation formulation outlined in section 5.4.2 where the distribution use of system (DUoS) charge is the main component of the grid price. The cost and net EV charge differences are summed for all zones, $z \in Z$, to give the bid cost[81], $C_{g,t}^{\downarrow}$,of the aggregated flexible asset g for timestep t.

$$C_{g,t}^{\downarrow} = \frac{\sum_{z \in Z}(c_{z,t}^{max} - c_{z,t}^{opt})}{\sum_{z \in Z}(p_{z,t}^{max} - p_{z,t}^{opt})} \tag{7-1}$$

The bid cost is calculated for each zone from the difference between the optimum cost $c_{z,t}^{opt}$ where net EV charge is not fixed in timestep t and the cost for the maximum

[81] In the context of the *Local market,* a bid is for a decrease in generation, which equates to an increase in demand to the maximum. Conversely, an offer is for an increase in generation which corresponds to a decrease in demand to the minimum (or increase in V2G injection).

net EV charge for timestep t, $c_{z,t}^{max}$, divided by the difference in net EV charge between the maximum and optimum net EV charge cases, $p_{z,t}^{max} - p_{z,t}^{opt}$.

Likewise, the offer cost[81], $C_{g,t}^{\uparrow}$, of the aggregated flexible asset g for timestep t is calculated by the difference in cost divided by the difference in net EV charge for the EV schedules for the optimum and minimum case ($c_{z,t}^{min}$) summed across all zones:

$$C_{g,t}^{\uparrow} = \frac{\sum_{z \in Z}(c_{z,t}^{min} - c_{z,t}^{opt})}{\sum_{z \in Z}(p_{z,t}^{opt} - p_{z,t}^{min})} \tag{7-2}$$

The bid and offer cost calculated for SP37 for *Network 18* are $C_{g,t}^{\downarrow} = £61.4/MWh$ and $C_{g,t}^{\uparrow} = £26.6/MWh$.

The bid cost is more than double the offer cost as it is more expensive to increase EV charging during SP37, due to the high DUoS price, than it is to increase V2G. However, increasing V2G during SP37 does increase the total EV charging cost compared to the optimal case. This is because many zones within *Network 18,* particularly those with a higher number of EVs, have limited headroom. In the optimum case, EV charging will be maximised at the cheapest times using the available headroom. However, there is limited headroom during the cheapest times, and increasing V2G during SP37 results in charging having to be shifted to more expensive periods to replace the power delivered as V2G.

A method has been developed to determine the minimum and maximum EV net demand flexibility, which is aggregated for all EVs in a LV network for a settlement period. An example calculation for bid and offer costs has also been provided, these costs can be entered into the *Local market* where the EV flexibility is made available to the DSO and TSO.

7.3 Local Market operation with aggregated LV flexibility

To demonstrate the integration of the proposed LV CMS and the *Local market* DSO-TSO coordination scheme, the EV flexibility from *Network 18* for SP37, calculated in section 7.2, is aggregated to an MV node in an extended MV/HV Cornwall distribution network model, and made accessible to the DSO and TSO in the *Local market.*

7.3.1 Extended Cornwall MV/HV distribution network model

The *Local market* is demonstrated on the MV/HV Cornwall network, shown in Figure 7-9, which has been extended with a section of 11 kV network connected to the LANN3J/3K primary substation within the RAME 33 kV network. The 11 kV network is a 46-bus section of the 247-bus Whitchurch network, produced during the *Flexible Networks* trial [213]. In the *Local market* network model, the power flow and EV flexibility from *Network 18* is aggregated to a secondary substation within the 11 kV network. Figure 7-10 shows the section of Whitchurch 11 kV network along with the connections to the Rame 33 kV network and the secondary substation at which *Network 18* is aggregated.

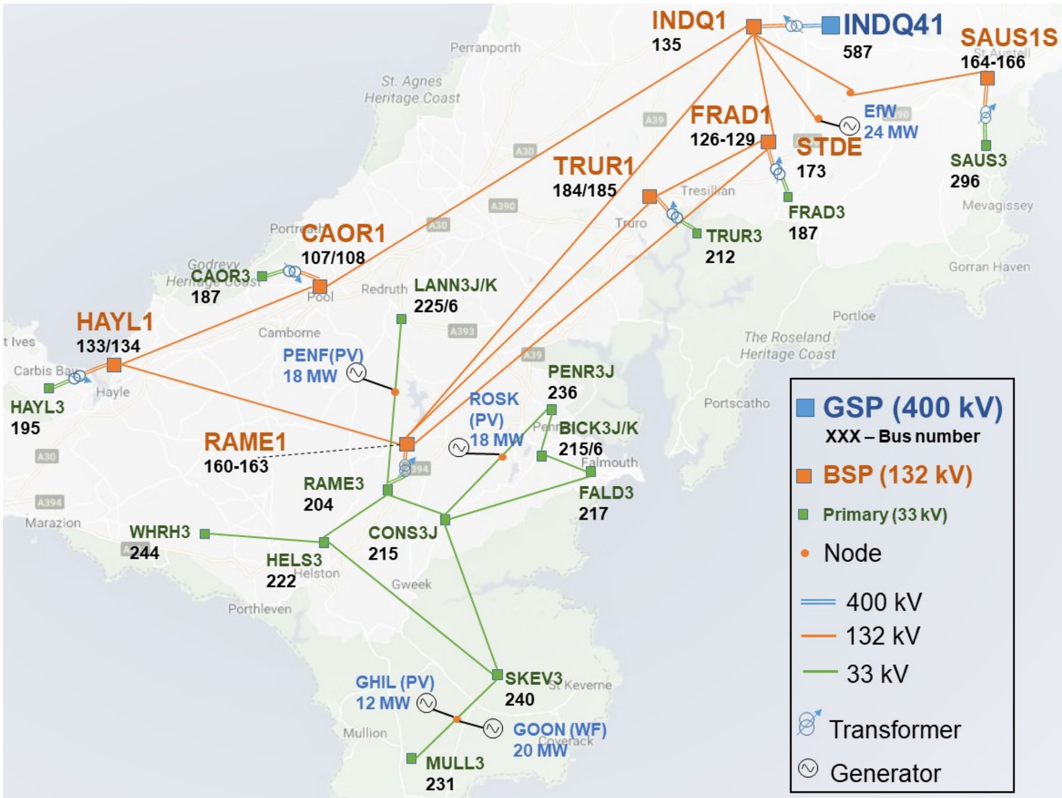

Figure 7-9: Schematic of Cornwall network, EfW - Energy from Waste Plant, WF - Wind Farm, BSP – Bulk Supply Point, GSP – Grid supply point.

7.3.2 Modelling inputs

A single half hour snapshot of the *Local market* is modelled for SP37, and for demonstration purposes it is assumed that during this period, the demand in the

Cornwall network is at the 2030 peak value (see Table 4-9) and all wind and PV generation output is zero, representing a potential scenario at 18:00 on a cold winters evening with low wind speed. The grid import price is set at £50/MWh meaning any additional upward flexibility that can be provided by the DERs at a cost below £50/MWh will be activated by the TSO if distribution network constraints allow. The bid/offer prices of DERs in the Cornwall HV network are set at the 'Cheap Curtailment' costs from Table 4-12, whereas the EV flexibility from *Network 18* has bid and offer costs of £61.6/MWh and £26.6/MWh, respectively. These are determined using (7-1) and (7-2) under the assumptions set out in section 7.2.4. In the *Local market*, the aggregated EV flexibility for *Network 18* is modelled as a generator located at the LV/MV interface shown in Figure 7-10.

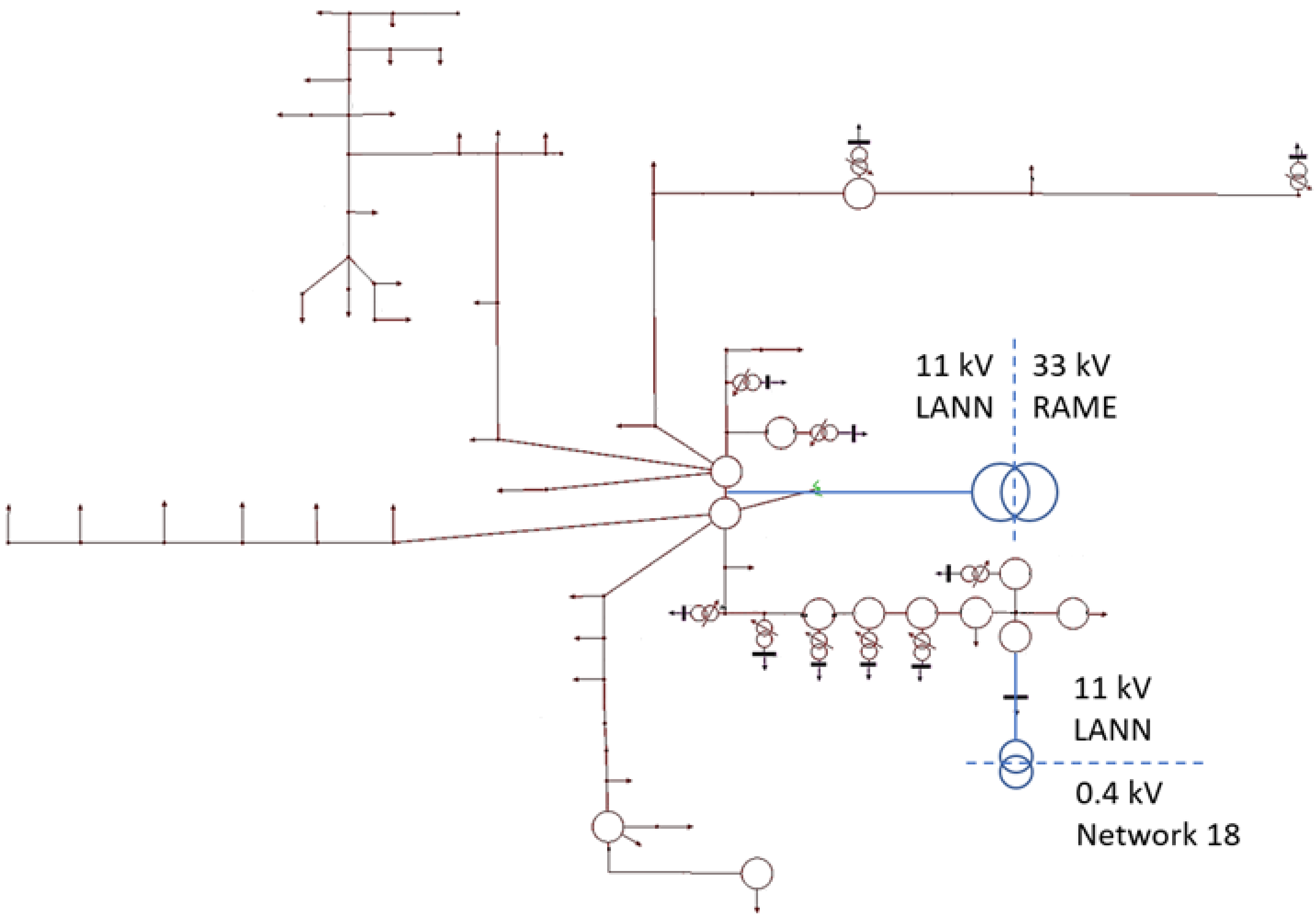

Figure 7-10: 46-bus section of Whitchurch 11 kV network [213] *with aggregation point for Network 18 (0.4kV) and connection point to Rame (33 kV).*

For SP37, the aggregated EVs have a set point of 0.26 MW ($p_{z,t}^{opt}$), upper bound (UB) of 0.506 MW ($p_{z,t}^{min}$), and lower bound (LB) of -0.05 MW ($p_{z,t}^{max}$) which are taken from Figure 7-7.

7.3.3 Local market results and discussion

In the *Local market,* the DSO firstly carries out a congestion check of the Cornwall MV/HV distribution network for all DERs set to their upper and lower bounds. The Rame DSO-TSO interface is modelled in the *Local market* and the *Network 18* flexibility is aggregated to the MV node connected within the extended Rame network shown in Figure 7-10. As renewable output (and UB) is set to zero, there is no export constraint or congestion for DERs at their UB. In this example, the Rame peak demand is within the BSP transformer capacity, and there is no other MV/HV thermal or voltage congestion for these demand and generation levels, therefore there is no requirement for any adjustments to DER LBs to ensure the peak demand is met.

The distribution network is therefore in the ‘green’ state in the *Local market* traffic light framework and there is zero cost to the DSO, as no adjustments to DER set points, LBs and UBs were needed. The DERs are cleared to participate directly in the TSO market, offering any flexibility within the bounds that were validated by the DSO.

In the TSO market, the TSO dispatches 0.25 MW of upward EV flexibility (representing increased V2G injection) for *Network 18* up to the UB of 0.51 MW for SP37. The *Network 18* flexibility offer cost of £26.6/MWh is lower than the grid import cost of £50 for the TSO, thus the TSO can save money by increasing the power flow from *Network 18* and subsequently reducing the import from the grid. Based on the margin between the grid import cost and the EV offer cost (£23.4/MWh), and the offered upward flexibility of 0.25 MW, the EV flexibility saved the TSO £2.90 in SP37 by reducing the grid import by 0.25 MW for half an hour.

The very modest saving of £2.90 for the TSO in the *Local market* is made by utilising flexibility from domestic V2G through the LV CMS for a single half hour SP. Nevertheless, this represents a significant opportunity for the TSO in accessing flexibility from LV assets – a key offering of the TSO-DSO transition. The LV CMS provides limits to the adjustments of LV flexible assets in the *Local market* to ensure that LV thermal and voltage constraints are respected[82], and the DSO congestion market within the *Local market* ensures that MV/HV network congestion is managed. Based on results for a single SP, the LV CMS appears to be highly compatible with the *Local market* assuming the CMP can pass bids/offers to the DSO at gate closure of the DSO market and respond to redispatch signals from the DSO or TSO in real-time.

The DUoS price used in the EV optimisation does not represent the full costs of EV charging, meaning the bid and offer costs offered by the CMP could differ from the £61.6 and £26.6/MWh which were calculated for SP37. Nonetheless, it is important to recognise how this EV flexibility could scale to provide an aggregated offering to the DSO and TSO. With this in mind, in the following section the available flexibility from EV charging is considered over an entire 24 h period for *Network 18* using the same methodologies presented in this section.

7.4 24 hour EV charging flexibility scheduling

So far in this chapter, the flexibility available from home charging of EVs has been considered for a single half-hour settlement period in *Network 18.* In this section, this is extended to consider the flexibility across a 24 h horizon from midday to midday for the same LV network for a winters' day. This provides an indication of the levels of aggregated flexibility available at different times of day that can be made available to the DSO and TSO in the *Local market,* which depends on EV charging behaviour and the available network headroom. It also shows how providing flexibility at one time of day impacts the dispatch of EVs, and the available flexibility, during the rest of day.

7.4.1 Methodology

To reduce the problem into a more readily analysed set of charging schedules, EV flexibility dispatch is considered for six 4 hour blocks for which maximum and minimum flexibility schedules have been determined using the same methodology as described in section 7.2 over the same winters' day (12th December 2013). A maximum and minimum net EV demand schedule is determined for a 4 hour block by

[82] The headroom and footroom limits used in the LV CMS have been validated for several days of EV optimisation results across five LV networks in section 6.3.4.

optimising the EV schedule (using the EV optimisation formulation set out in section 5.4) with the EV net charge fixed at the maximum and minimum possible values, respectively. Equations (7-1) and (7-2) are used to calculate bid and offer costs for flexibility, averaged over the 4 hour blocks, from the difference in cost been the minimum and maximum net EV demand schedules and the optimal schedule.

7.4.2 Results and discussion

Results are shown for the aggregated EV schedules in *Network 18* to provide minimum and maximum net EV demand for three selected 4 hour blocks (blocks 1,4 and 5) from midday to midday on 12th December 2013. The flexibility for all blocks is then presented along with the calculated bid/offer prices.

7.4.2.1 Block 1 EV charging schedule for maximum/minimum net EV charge

The aggregated *Network 18* EV charging schedules for providing minimum and maximum EV flexibility in block 1, which covers 12:00 to 16:00, is shown in Figure 7-11.

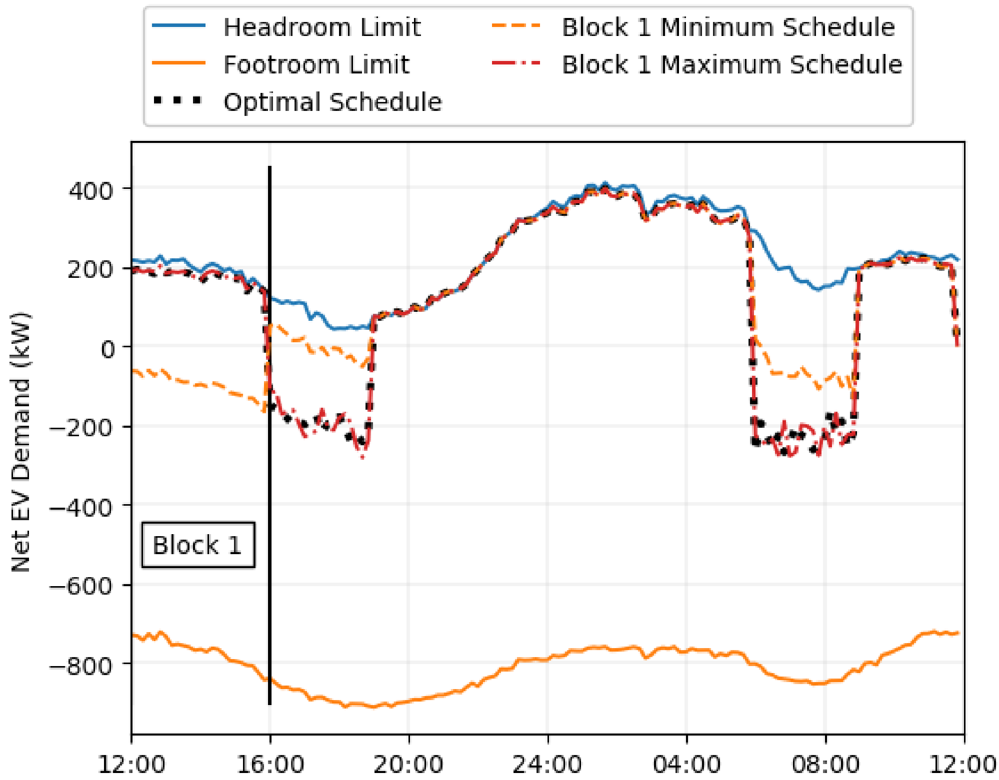

Figure 7-11: Block 1 Network 18 aggregated EV dispatch for full 24 hour period for provision of minimum and maximum EV flexibility on 12th December 2013.

The ‘Block 1 Minimum Schedule’ in the figure equates to the aggregated EV charging schedule to provide the lowest net demand (maximum export) during block 1 and the ‘Block 1 Maximum Schedule’ equates to providing the highest net demand (maximum import). The optimal charging schedule, which is the schedule produced by the EV optimisation formulation without providing any flexibility, is also shown.

The flexibility available depends on EV charging behaviour, the EV optimisation objective function and the available headroom and footroom. In this work, the main component of EV charging cost has been assumed to be the DUoS charge and it is assumed that this price is applied symmetrically for EV charging or V2G (i.e., V2G is paid for at the same price that charging costs at any point in time). Furthermore, a morning peak period has been artificially added to incentivise V2G in the LV CMS during the morning peak in HP demand (see section 5.4.2). While the headroom and footroom are relatively inflexible as these represent LV network constraints, the price optimisation is at the discretion of the EV aggregator (CMP) and could include wholesale, balancing or other price components. Therefore, it is important to recognise the times at which the available flexibility is dictated by the price optimisation strategy used by the CMP, and times at which it is limited by the headroom and footroom.

The optimal schedule in Figure 7-11 has negative net EV charging demand during the morning and evening peak DUoS price periods (16:00 – 19:00 and 06:00 – 09:00) shown in Figure 5-6 which is dictated by the CMP optimisation strategy. The negative net EV demand includes the provision of V2G injection which is assumed to be paid for at the DUoS price, representing revenue for the CMP.

In block 1 it is possible to provide V2G and a reduced net demand from the optimised schedule by an average of ~100 kW. However, this comes at the expense of reducing the V2G provided during the morning and evening peak DUoS periods where the V2G is reduced by a similar amount to the net demand reduction in block 1. This is an example of both the CMP optimisation strategy and headroom limiting the available V2G. If there was more headroom, it would be possible to provide more V2G at other times and replace the lost charge, but as the headroom is limited, providing V2G in block 1 reduces the V2G that can be provided at other times of day.

In block 1, and at most times of the day, upward flexibility is limited by the headroom irrespective of the CMP price optimisation. The EVs cannot provide any increased charging demand compared to the optimised schedule as they are already charging at the maximum headroom limit in the optimised case.

7.4.2.2 Block 4 EV charging schedule for maximum/minimum net EV charge

The aggregated *Network 18* EV charging schedules for providing minimum and maximum EV flexibility in block 4, which covers midnight to 04:00, is shown in Figure 7-12. The figure shows that by providing V2G between 24:00 and 04:00, the available V2G is significantly reduced in the high DUoS price periods.

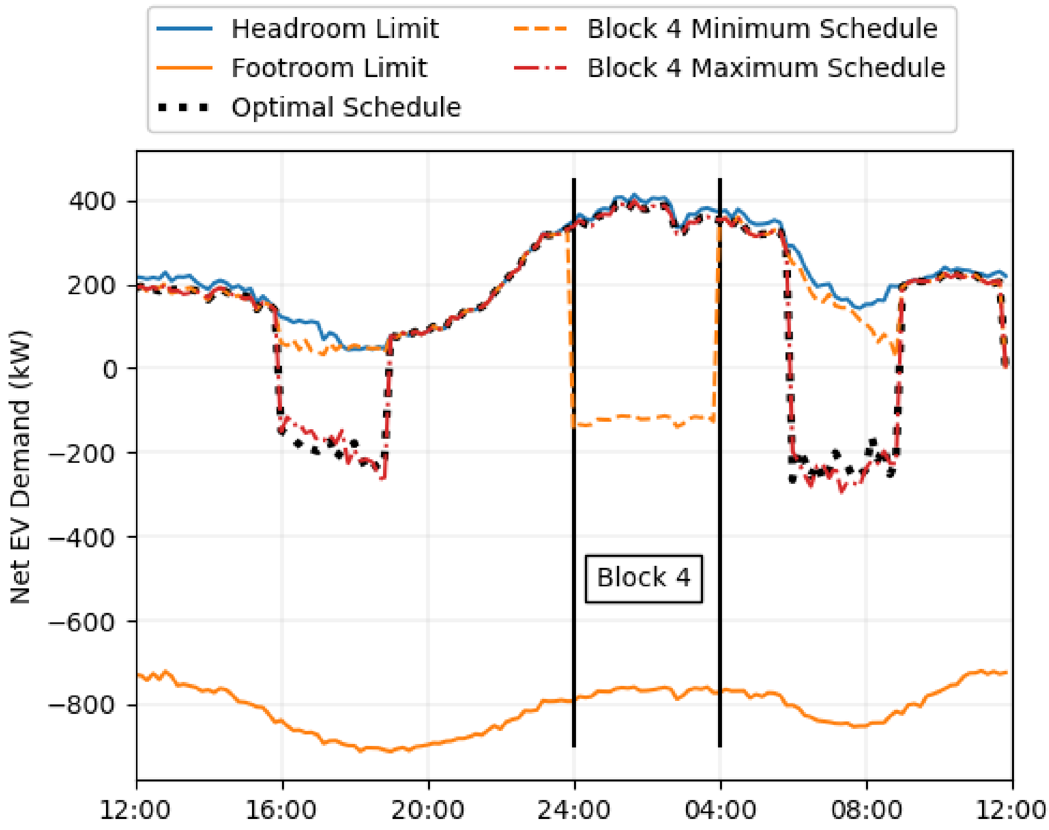

Figure 7-12: Block 4 Network 18 aggregated EV dispatch for full 24 hour period for provision of minimum and maximum EV flexibility on 12th December 2013.

Most of the available downward flexibility in *Network 18* can be offered during block 4. This is deduced from the lack of downward flexibility dispatched during the high DUoS price periods for the block 4 minimum schedule. If there was remaining flexibility it would be profitable to dispatch it at those times. The flexibility provided in block 4 is approximately 500 kW of reduction from the optimal schedule which is sustained for the 4 hour period. From midnight, it is possible to gain 2 MWh of flexibility from *Network 18* across 4 hours which represents the highest downward flexibility available at any time of day. However, it is unlikely V2G would be requested during block 4 by the DSO or TSO as this is during the period of overnight minimum demand on the electricity system. It is more likely that there would be a requirement from the DSO or TSO for increased demand overnight due to excess baseload[83] or renewable generation, however, there is no potential for upward demand increase overnight as the EVs are already charging at the headroom limit.

7.4.2.3 Block 5 EV charging schedule for maximum/minimum net EV charge

The aggregated *Network 18* EV charging schedules for providing minimum and maximum EV flexibility in block 5, which covers 04:00 to 08:00, is shown in Figure 7-13.

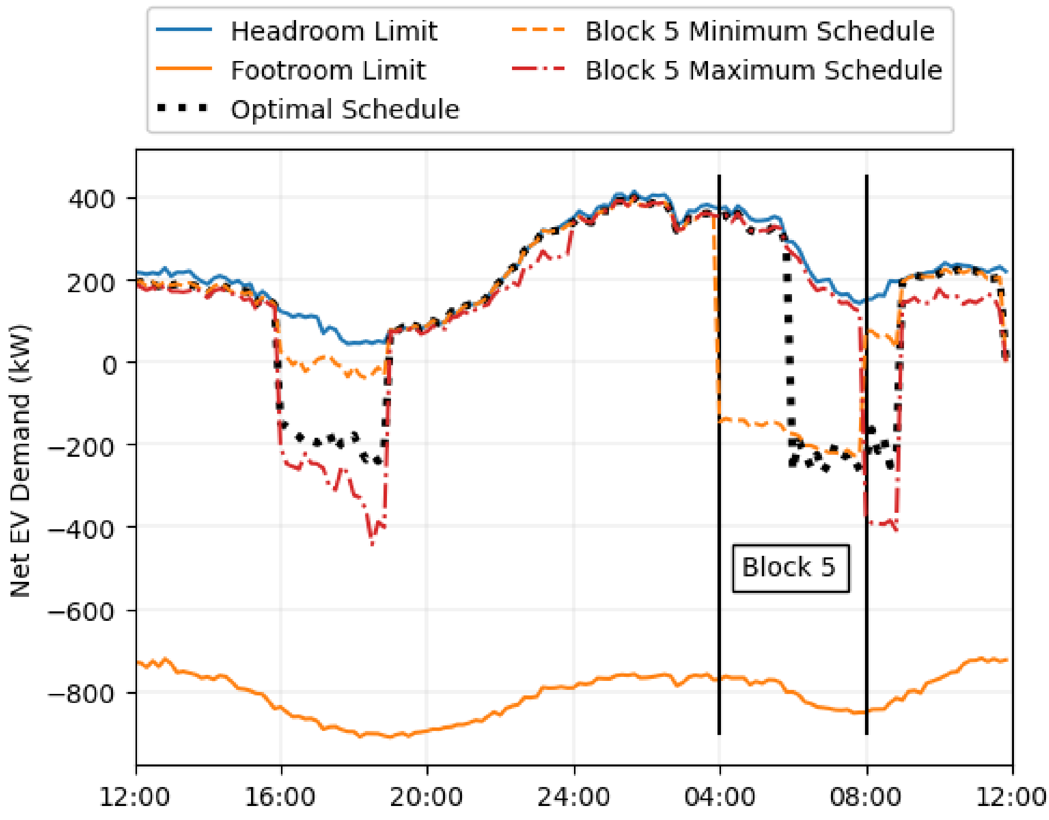

Figure 7-13: Block 5 Network 18 aggregated EV dispatch for full 24 hour period for provision of minimum and maximum EV flexibility on 12th December 2013.

83 For example, overnight storage heating is used to increase minimum demand (using Economy 7 tariffs [246]) to help match electricity generation from must run nuclear plant.

The figure shows that there is downward flexibility for the first half of block 5 and upward flexibility for the second half. This is because half way through block 5 V2G is provided in the optimal schedule in response to the high DUoS price from 06:00 to 08:00. In most of the blocks in this case study it is the headroom that limits available flexibility from *Network 18*, however V2G is being dispatched during the peak DUoS price periods, and this influences the available aggregated flexibility that can be made available to the DSO and TSO in the *Local market*. However, the DUoS price corresponds to periods of peak demand on the electricity system, therefore the optimised schedule of the CMP is likely to correspond to the requirements of the DSO and TSO in terms of reducing demand and increasing V2G during peak demand and increasing charging during the overnight period of minimum demand. This highlights the importance of the optimisation strategy used by the CMP, and of how well it aligns with the DSO and TSOs requirements. For example, the CMP's EV scheduling optimisation strategy could be to minimise carbon intensity, using grid carbon intensity data as demonstrated in [39].

The mean carbon intensity in the above figure follows a similar trend to the DUoS prices, namely higher intensity during evening and morning peak demand periods. However, as with the wholesale market price there is greater variability, and the optimisation of EVs using carbon intensity or wholesale market signals may not always produce desirable outcomes for the DSO and TSO. The complementarity of different EV optimisation strategies and the DSO/TSOs requirements is identified later as part of the recommendations of this thesis as an area requiring further work.

7.4.2.4 All blocks maximum/minimum net EV charge

Figure 7-14 shows the appended results of minimum and maximum EV charging demand for each of the 4 hour blocks of EV flexibility for *Network 18* considered in this case study.

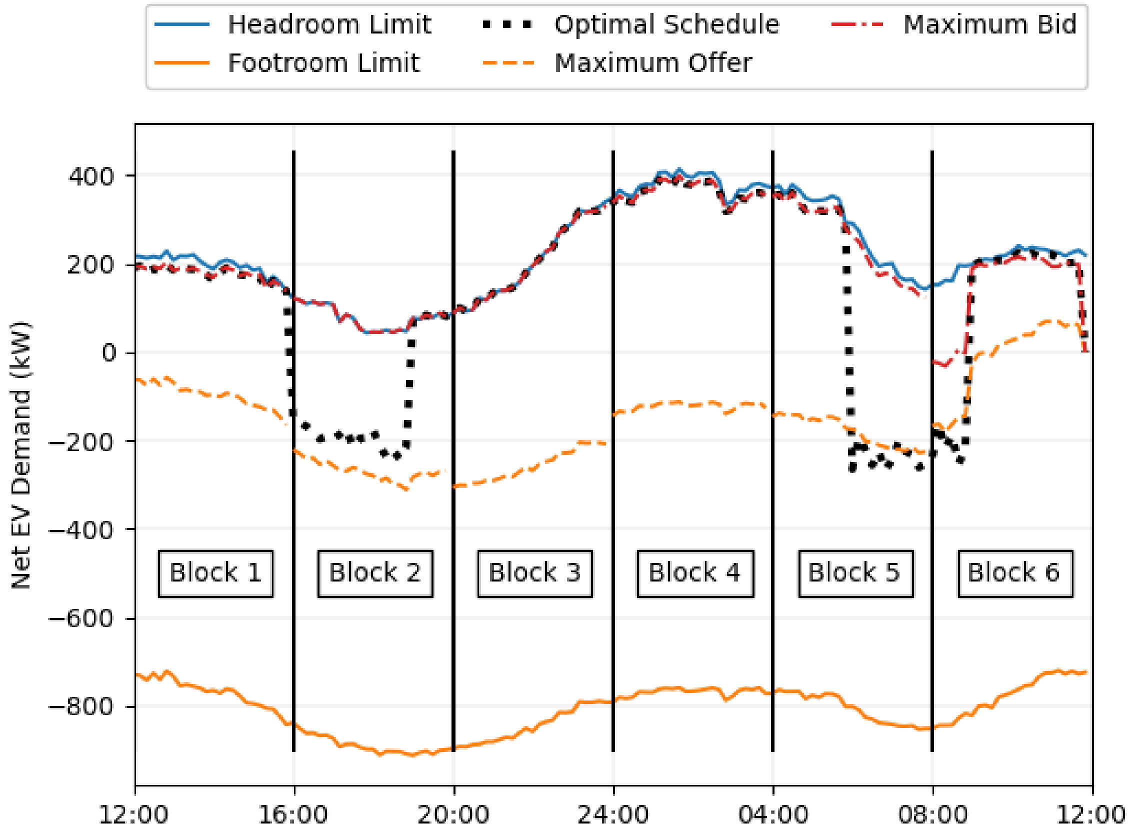

Figure 7-14: Network 18 aggregated available flexibility for 6 x 4 hourly blocks over 24 hours on 12th December 2013.

Note this figure provides the minimum/maximum net EV charging demand for each block but does not show full resulting schedules which are shown for blocks 1,4 and 5 in Figure 7-11, Figure 7-12 and Figure 7-13 respectively. As discussed in the analysis of the full schedules, activating flexibility in one block will affect the flexibility remaining in other blocks which is not captured in this figure.

Figure 7-14 shows that in this case study the full footroom is not used at any time of day used when providing V2G. Counterintuitively, the ability to provide V2G in *Network 18* on a winters day (12th December*)* is limited by the headroom and not the footroom. As this case study takes place over a winter's day, with high levels of HP demand, the available headroom is limited to prevent thermal or voltage violations using the methodology described in section 5.3.1. Any V2G must be replaced by charging to ensure EVs reach their required final SoC, and as there is limited available headroom for charging, this limits the level of V2G that can be provided. This could be an important constraint on the application of the LV CMS to networks with limited headroom, as it places more importance prioritising V2G at the time of maximum benefit to the DSO and TSO. If this flexibility is offered to the DSO and TSO in the *Local Market,* the DSO would have first priority for using the V2G flexibility in the event of any MV/HV import constraints, however the TSO could require V2G for frequency response or system wide balancing. The scheduling and prioritisation of V2G during potential distribution constraint and transmission system imbalance is an area for future research work and is not taken any further in this thesis.

The amount of V2G flexibility available in block 6 between 08:00 and 12:00 is significantly lower than other times of day. This relates to commuter EV charging behaviour where many cars leave for work in the morning by which time the EVs must be fully charged. Therefore, the amount of V2G available in block 6 is limited by the time available to make up any lost charge and return the EVs to the required final SoC. With the increased uptake of HPs, a morning peak in demand could be introduced to the electricity system (see the HP demand profile in Figure 6-7) and there could be increased requirement for V2G at this time to reduce peak demand on the electricity networks at all voltage levels. In this case, changes in EV behaviour such as more home working could be a benefit to the DSO and TSO as there would be more EV flexibility available during block 6 due to more EVs remaining plugged in at this time.

7.4.2.5 All blocks bid and offer prices

Figure 7-15 shows the prices and available flexibility for each of the 4 hour blocks. Prices are calculated using the same methodology described in section 7.2.4 with the only difference being they are averaged over 4 hours rather than a single SP. The prices represent the difference in charging cost (for the DUoS price optimisation) between the optimal charging schedule and the upward or downward flexibility schedule. In Figure 7-15 the bid price relates to the price for downward flexibility in terms of decreased export (meaning increased EV charging) and the offer price relates to the price for upward flexibility in terms of increased export (decreased charging and increased V2G). No bid prices are shown for blocks 3 and 4 as there is no downward flexibility available during these periods.

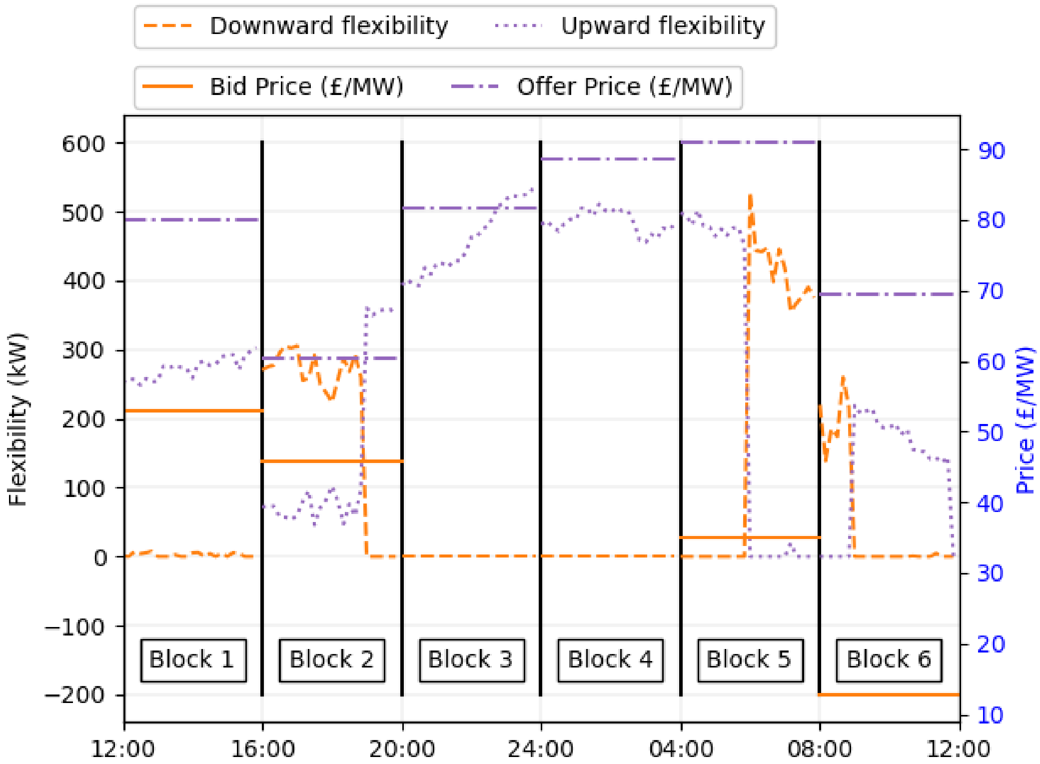

Figure 7-15: Available upward and downward flexibility and bid/offer costs for network 18 for 6 x 4 hour blocks over 24 hours.

The offer prices are high overnight as this is the most expensive time to provide V2G due to significantly reducing the available income from V2G during the peak DUoS price periods. The bid prices for downward flexibility during the periods of high DUoS price (blocks 2 and 5) are reasonably low as increased charge during one high DUoS price block can be replaced with increased V2G during the other high DUoS price blocks. This can be observed in Figure 7-13 where increased charging during block 5 results in increased V2G during block 2 for the 'Block 5 Maximum Schedule'.

While it is recognised that these results are specific to the objective function and price optimisation for the EV scheduling, there are some general trends that can be observed. These are:

1. In more constrained networks with limited headroom, moving V2G away from any peak price periods will likely cost the DSO and TSO more in the *Local market*. This is because it will reduce the income available to the CMP if they can only provide a limited supply V2G due to limited network headroom. Ideally the price metric used by the CMP will align with the DSO and TSOs requirements for EV

charging demand scheduling, if they do not align the CMP may submit high bid and offer prices to the *Local market* to change their price optimised EV charging schedule.

2. Less constrained LV networks with more headroom could be a source of cheaper flexibility to the DSO and TSO. If there is more headroom available, the cost of providing V2G could be reduced as it can be replaced more easily using the headroom available at the cheapest times.

The case studies considered have been valuable in demonstrating the potential areas for further work in EV scheduling and how network headroom can limit the availability for both charging and provision of V2G. There may be a need to pair flexibility bids/offers to the DSO/TSO, given that providing flexibility in one time period effects the overall charging schedule. In the following section, a further discussion is provided which considers the results of aggregated EV flexibility for *Network 18* for both the single SP and the 24 hour period from the point of view of provision of aggregated flexibility as a nationwide 'EV battery' or virtual power plant.

7.5 Discussion of findings

In the single SP example, 0.25 MW of aggregated upward EV flexibility was estimated for a single LV network (*Network 18*) with 235 EVs. This flexibility was then offered to the *Local market* at one of the 35 secondary (11/0.4 kV) substations within the Whitchurch 11 kV network. Within the Cornwall network there are 49 primary substations. Assuming *Network 18* has an average number of customers for LV network in Cornwall[84], and that there are approximately 35 such networks (connected to the secondary substations) in an average Cornwall 33 kV network[85], the total number of LV networks in Cornwall is 1715. Assuming 0.25 MW upward flexibility from all these networks for SP37, the EV flexibility from the Cornwall network would be 429 MW which is equivalent to a large wind farm or open cycle gas plant. However, from

[84]In section 6.1 it was found that *Network 18* has a number of customers close to the median of the 25 LVNS networks which is the largest publicly available set of realistic LV network models [187].

[85]11 kV data is not available from the WPD Long Term Development Statements [16] therefore it is assumed that the Whitchurch 11 kV network is representative of 11 kV networks in the Cornwall region.

the 24 hour case study it was found that on constrained LV networks with limited headroom due to high levels of HPs, this flexibility is not available at all times of day and there is a lack of downward flexibility (equating to increased EV charging) at most times of day during the winter. The maximum available upward flexibility in *Network* 18 was found to be ~0.5 MW which could be sustained for 4 hours overnight (see Figure 7-12), but activating this significantly reduced the upward flexibility available for morning and evening peak demand periods where it could be more valuable. At the morning and evening peak times (see Figure 7-15), the upward flexibility is more limited to between 0.3 – 0.45 MW which could only be sustained for roughly 1-2 hours.

There are clearly many assumptions involved in the aggregated estimation of 429 MW upward flexibility from the Cornwall network for SP37. However, the upward EV flexibility value of 0.25 MW for *Network 18* in SP37 is based on the constraints of realistic travel behaviour from census data (represented by the travel diaries in section 5.4). Furthermore, the 0.25 MW flexibility can be provided while respecting the thermal and voltage limits in *Network 18* using the headroom and footroom limits under the LV CMS. The 429 MW estimate is therefore an improvement on approximating available EV flexibility based on the number of EV chargers without considering charging schedules or network constraints, as is carried out by EV aggregators in promotional press releases [214]. However, from the 24 hour study it is shown that on a network with limited headroom where the LV CMS is applied, it is not accurate to assume 0.25 MW upward flexibility would be available all day, as the available upward flexibility was seen to vary between 0 MW at certain times to 0.5 MW overnight (see Figure 7-15). If 0.25 MW upward flexibility was always available over 24 hours this would equate to 6 MWh of across the day, however in the case study considered the maximum volume of upward flexibility *Network 18* could provide is around 2 MWh overnight and at other times of day there would be less available. It is important to note that these results were for a winters' day and the headroom available during summer would be far greater in PV rich networks. In the summer there would be greater demand for downward flexibility (increased EV charging), particularly during the middle of the day, to reduce curtailment of excess PV generation. In future work, case studies should be carried out for summer months to explore network headroom and footroom available using the LV CMS along with the aggregated EV flexibility across the day. Furthermore, the studies could consider if the available flexibility matches the needs of the DSO and TSO in the *Local market.*

Further work is also required in providing a more accurate probabilistic estimate of EV flexibility, including uncertainty in EV charging behaviour. Furthermore, the EV optimisation strategy by the CMP needs to be considered in more detail as this could significantly impact the costs for flexibility submitted by the CMP to the DSO and TSO in the *Local market*. If the optimal EV schedule determined by the CMP does not align with the DSO and TSOs requirements for flexibility, then particularly for constrained networks with limited availability of flexibility, this could increase the cost of using EV flexibility to the DSO and TSO. Less constrained networks, without the need for a LV CMS could be the cheapest source of EV home charging flexibility for the DSO and TSO. This is because the CMP would be less constrained in their ability to adjust from their optimal schedules and could therefore potentially provide V2G at a lower cost. This could strengthen the business case for reinforcing LV networks rather than applying a LV CMS particularly if it means access to cheaper flexibility to the DSO and TSO from aggregated EV home charging without a CMP imposing large opportunity costs.

With the above reservations in mind, consider the scenario where 100 MW of the estimated 429 MW upward EV flexibility in the Cornwall region was available to the TSO. Assuming the EV upward flexibility is activated by the TSO instead of gas generation[86], and by way of example, that it can do so at the cheaper price of £50/MWh, this would represent a saving of £1750 to the TSO in one half hour settlement period. It is at these scales that aggregated EV flexibility could make a significant contribution to reducing the costs of system operation, particularly if it can offer a cheaper alternative to adjusting output from gas generation for balancing intermittent renewable generation output, which cost the TSO between £150m to £250m a year between 2013 and 2017 [181].

Looking at the potential for EV flexibility from a national perspective, there are approximately 230,000 secondary substations in GB [215]. Considering a future with 100% EV uptake of the entire GB car fleet. If only 10% of the estimated 0.25 MW in upward EV flexibility is available across all SPs and secondary substations, this would translate to a national EV battery of 5.7 GW which exceeds the 2.5 GW of pumped hydro capacity in GB in 2018 [14].

[86] The average volume weighted offer cost from gas generation in the GB BM in 2018 was £85/MWh [179].

Given the sheer number of LV networks in the GB power system, solutions to manage network congestion and aggregate flexibility must be scalable. The LV CMS provides the potential to parallelise the optimisation of LV flexibility assets across network zones, and the *Local market* can also be parallelised across DSO-TSO interfaces. In essence, this allows what would be an intractably large problem to be divided into a number of tractable sub-problems that can be solved in parallel. Furthermore, having LV network zones contracted to multiple CMPs in the LV CMS and DSO-TSO interfaces operated by multiple DSOs in the *Local market* increases the potential for competition. This competition can be between DERs in providing flexibility across different DSO regions in the *Local market* and between CMPs for contract to manage LV flexible assets in the LV CMS. Ultimately this competition can help drive down the cost to consumers for an electricity system with high levels of renewable generation and electrified heat and transport on the road to net zero.

7.6 Chapter Summary

In this chapter, the integrated operation of the LV CMS and *Local market* is demonstrated for a single half hour SP. A method is exhibited for the CMP to calculate the available flexibility from EV home charging and associated bid/offer costs. The EV flexibility is then aggregated to an MV node and passed to the *Local market* to allow the DSO and TSO to access the EV flexibility. The LV CMS methodology and CMP flexibility calculation has been applied to a single LV network (*Network 18*) which is attached to the Cornwall MV/HV network by aggregation to a secondary (11/0.4 kV) substation.

From an initial demonstration for a single SP on a winters' day, the LV CMS and *Local market* appear to be highly compatible: the TSO was able to access 0.25 MW of aggregated upward EV flexibility (from V2G injection) from *Network 18* through the *Local market* operation on the Cornwall network. The available flexibility from EVs in *Network 18* was considered over 24 h for a winters' day and it was found that the lack of network headroom significantly limited the availability of downward flexibility as well as increasing the opportunity cost of providing V2G. It was shown that up to 0.5 MW aggregated flexibility was available overnight, but this could only be sustained for around 4 hours and would deplete the flexibility available at other times of day.

Chapter 8:

Conclusions and Future Work

Electricity systems are undergoing a transition from being largely centralised to having an increasing share of distributed resources such as domestic EVs, solar PV and battery storage. A key aspect of operating the electricity system of the future is coordinating access to the flexibility from these distributed assets between the DSO and TSO [75]. This has been considered in the EU SmartNet [38] project and as part of the Future Electricity Utility Regulation (FEUR) reports in the USA [74] as well as by the Energy Networks Association (ENA) in the UK [36]. However, effective operational coordination of the DSO-TSO interface and scalable LV congestion management tools remain as areas in development for power systems. Considering this, the first research question in this thesis is:

> How can access to distributed flexibility be coordinated between the DSO and TSO for system balancing and distribution system congestion management?

To answer this, in Chapter 2 the state-of-the-art in DSO-TSO coordination models is reviewed and two of the most promising methods from the SmartNet project, the *Local market* and *decentralised Common DSO-TSO market* (referred to in this thesis as the *Decentralised market),* are selected for further consideration. These models have been selected as they assign responsibility for distribution network management to the DSO as recommended in the FEUR report [74]. In the *Local market*, DERs are cleared by the DSO to participate directly in the TSO market whereas in the *Decentralised market,* the DSO aggregates DER flexibility to the T-D interface for participation in the TSO market. Based on case studies developed and conducted as part of this thesis, the following is concluded:

- The *Local* or *Decentralised market* models are compatible with existing transmission system balancing markets in GB, with the potential to run in advance of, or in conjunction with the TSO balancing markets.

- The *Local Market* is superior to the *Decentralised market* in terms of reduced complexity, improved tractability, and better compatibility with existing GB TSO balancing market operation.

A novel contribution arising from Chapter 3 of this thesis is the development of a 'traffic light' style implementation of the *Local Market* which forms the basis of the journal publication 'Design of a DSO-TSO balancing market coordination scheme for decentralised energy' [216]. In the traffic light scheme, the DSO clears DER upper and lower bounds (of active power output) for participation in the TSO market, to ensure the distribution network is operated within thermal and voltage limits. The *Local market* is applied to distribution network congestion management on balanced MV/HV networks in Chapter 4 and provides a new mechanism to compensate DERs for the opportunity cost of adjusting their lower and upper bounds in the TSO market.

The priority of access to DERs between the TSO and DSO is a central element considered in this thesis when addressing the question of coordination. This is assessed in Chapter 4 where the *Local market* is applied in timeseries analysis on the Cornwall distribution network. A varying grid price is employed as part of the timeseries analysis to represent the competition between the DSO and TSO for flexibility from DERs. The main findings for the 2030 representative scenarios modelled, with high levels of DERs, are as follows:

- In the *Local market* implementation, the DSO has first priority of access to DER flexibility to solve distribution network constraints, which can as a result restrict the volume of flexibility available to the TSO.
- The DSO's actions did not severely limit the access of the TSO to DERs and in most cases modelled, the DSO and TSO objectives were aligned.

Looking ahead, the distributed flexibility from the home charging of millions of EVs connected to LV networks may be a valuable, exploitable, set of resources in balancing intermittent renewable generation at transmission level. Mechanisms will be required to ensure that the aggregated flexibility from such sources is available to the DSO and TSO in an equitable and timely bases. This gives rise to the second research question of this thesis:

> How can distribution system congestion management be scaled and coordinated with the TSO for millions of flexibility providers down to LV level?

To address the first part of this question at HV level, in Chapter 4 the scalability of the *Local market* DSO-TSO coordination scheme is assessed and compared with an equivalent *Centralised* market where distribution and transmission are managed in a single combined model. In this work, DSOs are assumed not to be electrically connected, allowing individual DERs to be associated with a single DSO and for their markets to operate in parallel. Case studies carried out for multiple DSOs operating 33-bus HV distribution networks in the *Local market* provide the following conclusions:

- The *Local market* can be easily expanded to accommodate multiple DSOs providing flexibility to the TSO and supports competition between independent aggregators for providing flexibility across multiple DSO-TSO interfaces.
- Beyond three DSOs, the *Local market* optimisation solves in less time than the equivalent *Centralised* model. This presents the prospect of an alternative set of options regarding system operation through the introduction of a regional balancing market that can therefore be solved across multiple DSO markets (connected at each D-T interface).
- The suitability of such a model would be governed by the incumbent market arrangements, the degree of penetration of DERs (sufficient capacity per DSO area) and an acceptable level of remuneration for DSO market participants.

To address the LV network aspect of the second research question of this thesis, in Chapter 5 a novel contribution is made by developing a tractable LV CMS which separates the LV network modelling activity carried out by the DSO, from optimisation of the LV flexibility by an aggregator. In Chapter 6, the LV CMS has been successfully applied to maximising the hosting capacity for HPs and optimised EVs on a set of representative LV networks which forms the basis of the journal publication 'Hosting capacity assessment of heat pumps and optimised electric vehicle charging on low voltage networks' [217]. By applying the LV CMS to networks with between 200 and 335 customers, it is concluded:

- The hosting capacity for EVs can be more than doubled using EV optimisation compared to 'dumb' (uncoordinated) charging with similar HP capacities.
- For the electrification of heat and transport, LV network upgrades should be considered on a network by network basis.
- Even with the application of the LV CMS, some networks were seen to require upgrades for a low level of HPs and EVs (of up to 25%); in some cases, optimised

EV charging was shown to allow significant HP and EV capacities to be realised (greater than 50%) without the need for upgrades; and others were shown not to require any active management or upgrades for 100% HP and EV capacity.

To address DSO-TSO coordination of flexibility down to LV in the second research question, in Chapter 7 the integrated operation of the LV CMS and *Local market* has been demonstrated for a single half hour SP. Flexibility from domestic EV charging is aggregated to an MV node and made available to the DSO and TSO in the *Local market*. For the single SP studied (18:00 -18:30), 0.25 MW of upward EV flexibility was estimated for a single LV network with 235 EVs, and in the *Local market* this flexibility was accessed by the TSO to reduce grid import to the Cornwall network during a period of peak demand and zero renewable generation output. This result illustrates the following conclusion:

- The tools developed in this thesis can allow EV flexibility connected at 400 V to be made accessible to the TSO in system balancing at 400 kV, while respecting three-phase voltage and thermal limits at LV.

The objectives of this thesis have been realised in that DSO-TSO coordination models have been developed, however more work is required to assess the market rules and the allocation of costs between the DSO and TSO. The same applies to accessing flexibility from LV where a methodology has been developed but further case studies are required to demonstrate the scalability of the method for different seasons, with different and potentially competing requirements of the DSO and TSO.

8.1 Industry implementation of this work

In most established electricity systems such as those in GB and elsewhere in Europe, there is currently a limited requirement for coordination between the TSO and DSO as the distribution network is largely operated passively (within its 'copper plate' capacity) and the TSO has unrestricted access to DER flexibility. However, with increasing levels of DERs, there is potential for distribution networks to operate closer to their thermal and voltage limits. This can result in the DSO of the future also requiring DER flexibility to solve distribution network constraints and can reduce availability to the TSO. The tools developed in this thesis are designed for use by the DSO and TSO of the (near) future when distribution networks become more actively managed and both the DSO and TSO access to DER flexibility. The changes required for the *Local market* and LV CMS to be implemented in the GB electricity system include changes to the BM trading arrangements, administered by Elexon [169], changes to use of system charges, levied by the DNOs and NGESO and regulated by Ofgem [170] and a mechanism for managing micro-payments. The role of new entities such as aggregators and third party market operators would need to expand and be more clearly defined. Another requirement for the implementation of this work is the widespread adoption of ICT including smart metering, communication and network monitoring down to LV.

The methodologies developed in this thesis would be useful for constrained areas of distribution network where congestion can lead to large reinforcement requirements. Unconstrained distribution network regions with adequate network headroom would not benefit from the methodologies developed in this work. Full network models would be required down to LV to apply the LV CMS which is a massive undertaking for DNOs given there are 230,000 secondary substations in GB with limited to no monitoring or network models beyond the secondary substation.

For the *Local market* to operate, the DSO and TSO must potentially dispatch tens to hundreds of thousands of DERs and model large networks with potentially hundreds of thousands of nodes. This presents a ‘big data’ problem for the network incumbents or at least one with significantly more data than is currently managed. As such, there will be a requirement for a high level of automation of dispatch instructions and network optimisation, using improved, faster alternatives to the ACOPF approach used in this thesis along with probabilistic techniques to forecast generation and demand at a significantly higher granularity than is currently practised. DSO markets such as in the proposed *Local market* will potentially make use of cloud based computing and communication via Application Programming Interface (API) as used in the flexible power market for DER flexibility [71]. In this case, with widespread adoption there will be a need for robust cyber security protocols and reliable internet infrastructure to ensure the secure and reliable provision of flexibility from DERs, especially if they are relied upon by the DSO and TSO for stable grid operation.

8.2 Future work

Coordination schemes are still emerging and with the full definition of terms just beginning to be developed (e.g. [36]), 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 which could be implemented in the DSO-TSO coordination mechanisms in future work. The same can be said for the EV optimisation work in this thesis which assumes perfect knowledge of EV charging behaviour. In future work, probabilistic forecasting methods should be applied to give a more realistic estimate of the available EV flexibility, including uncertainty in EV home charging behaviour. Furthermore, studies on the available flexibility from EV home charging at different times of day could be carried out which should also consider the effects of changing the timing of the EV optimisation window.

Along with the addition of probabilistic forecasting methods, the following extensions could be made to the *Local market* DSO-TSO coordination model in future work.

- Development of methods to minimise or remove the loss estimation error which results in a small mismatch in T->D flow calculated by the DSO and TSO.
- Examination of the rules of the *Local market* and the allocation of costs and benefits of DER flexibility between the DSO and TSO. For example, further modelling could be carried out to compare dispatch and subsequent costs to the DSO and TSO with different DER bidding strategies in the DSO and TSO markets.
- Implementation of more tractable formulations than the ACOPF applied in this thesis, such as linearised ACOPF or dual decomposition for application to MV/HV distribution networks with tens to hundreds of thousands of nodes.

The LV CMS methodology applied in this thesis is conservative in that a ‘worst case' headroom is used and applied to all days; in future work this could be enhanced by the use of a day-ahead forecasted headroom linked to temperature for example. The optimisation of EVs during the summer could also be studied using the same methodology, with a focus on solar PV, and alternative travel diaries could be included to reflect changing travel habits such as increased home working. Another important development of the headroom methodology would be in producing generalised headroom profiles linked to key network parameters to save re-calculating the headroom for every zone. More case studies could be carried out on the integration of the LV CMS and *Local Market* to consider the flexibility available to the DSO and TSO from LV assets during different network congestion scenarios (e.g., due to high PV generation output during summer). Finally, the impact of different EV optimisation strategies on the availability and cost of flexibility to the DSO and TSO could be studied

Appendix A: Background to the GB Electricity System

The congestion management and DSO-TSO coordination schemes proposed in this thesis are to be compatible with the existing GB electricity market arrangements. Therefore, an overview of GB electricity markets is provided, including developments in the electricity system structure, detail on the GB balancing mechanism (BM), power exchanges, ancillary services and the decentralisation of supply. Most European liberalised electricity markets operate with separated wholesale market and system operation activities [155], therefore the following background to GB market operation is relevant to other European electricity markets.

A. 1. GB electricity system structure

The GB electricity market structure has been continuously evolving since the national grid became fully integrated in 1938. The grid was a vertically integrated, nationalised system from 1938 up until 1990 at which point the electricity supply and transmission systems began the process of privatisation. In 2005, the New Electricity Trading Arrangements (NETA) were extended to include Scotland and became the British Electricity Trading and Transmission Arrangements (BETTA) which allows electricity to be traded privately in bilateral contracts and auctioned in power exchanges ahead of time and then balanced in real time using the BM operated by NGESO [218].

Settlement of any imbalances between ‘contracted volumes' (adjusted for any bids/offers accepted in the BM), and the metered volumes which were actually delivered, is carried out after the event by Elexon [169]. Elexon are the Balancing and Settlement Code (BSC) administration company, a wholly-owned subsidiary of National Grid ESO. In the current GB electricity market, private generators trade electricity with suppliers in the wholesale market. These suppliers have contracts with customers (domestic and businesses) settled through the retail market.

The wholesale electricity market in GB is dominated by over-the-counter trades up to two years ahead of delivery, representing 83% of traded volumes in 2017 [219]. Closer to delivery, energy is traded in power exchanges via day-ahead auctions for hourly products and four further auctions (two of which only opened on 30 September 2018) and an intra-day exchange for half hourly products. The TSO also operates ancillary markets with auctions for long term contracts negotiated a month or more in advance. A timeline of the GB electricity market trading is shown in Figure A-1 and further detail on the power exchanges and relevant ancillary services are presented below.

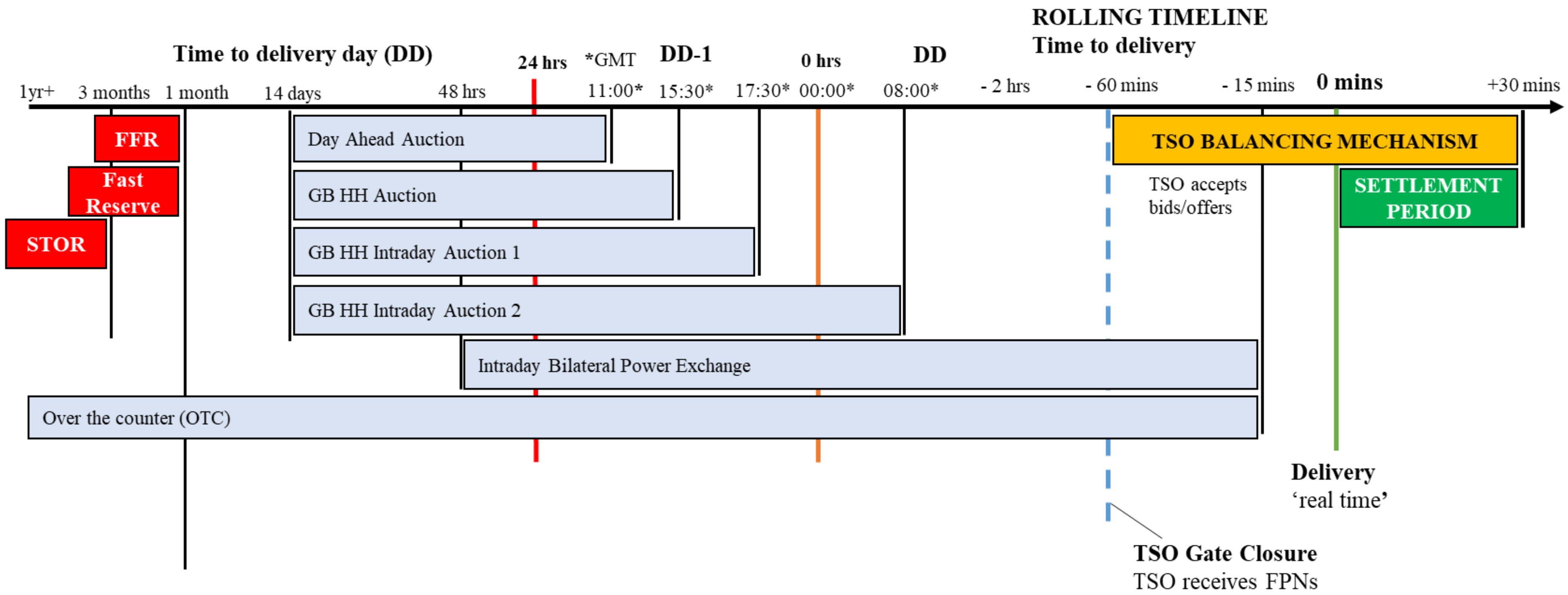

Figure A-1: Timeline for GB electricity markets; data: [7] [156] [157]. *MFR – Mandatory Frequency Response, FFR – Firm Frequency Response, STOR – Short Term Operating Reserve, FPN – Final Physical Notification.*

A.1.1 Power exchanges

Power exchanges are an important mechanism for market participants to adjust positions closer to delivery in auctions as well as facilitating bilateral trades up to 15 minutes prior to delivery. Although bilateral trades make up the majority of total traded volumes in GB, partly due to higher churn i.e., the same unit of energy being traded multiple times, a significant percentage of delivered volume in GB is traded in the Day Ahead (DA) power exchange auctions, at over 40%. At the time of writing this thesis, the power exchanges across 19 European countries (making up around 85% of European electricity consumption), are linked using market coupling [220]. Market coupling involves using available cross border capacity to minimise the price difference between two or more areas which provides an effective price signal for cross-border transmission capacity.

The existing power exchanges operating in GB are as follows:

- 11 AM gate closure DA in EPEX SPOT [156] and Nord Pool N2EX [157]. These markets are linked through a virtual interconnector with infinite capacity and no losses so clear at the same price. They are connected to the European Power exchanges via interconnectors. The products traded are hourly.
- 3:30 PM gate closure GB market DA in EPEX SPOT with half hourly products.
- Intraday Markets: 2 intraday markets have recently been introduced by EPEX SPOT with gate closures of 17:30 the day before and 08:00 on the day. These are GB markets with half hourly products coupled with Ireland.
- Spot market/over the counter (OTC) bilateral: participants can submit anonymous bids/offers in the Eurolight trading system (coupled with the European power exchanges) which are matched bilaterally by the market operators up to 15 minutes before delivery.

Electricity trading is carried out in GB with no consideration of network constraints or of system imbalance. It is the job of the TSO to manage network constraints and ensure that supply and demand are balanced in real time to maintain the system frequency at the statutory required 50 Hz (+/- 0.5 Hz). The main mechanism used by the TSO to do this is the BM along with ancillary service contracts for frequency response and reserve products which are briefly described in the following sections.

A.1.2 Balancing mechanism

The GB balancing mechanism is the system used by the TSO to balance supply and demand in real-time by adjusting the positions of balancing system parties. The balancing system rules are set out in the BSC, which is administered by Elexon. All licensed generators, suppliers and distributors must sign the BSC. Balancing parties submit their final physical notifications (FPNs) to the SO 1 hour before delivery along with offers to increase generation (or decrease demand) and bids to decrease generation (or increase demand).

Parties must pay for being out of position, although they pay for the difference between metered volumes and contracted volumes, not the FPNs which are for providing a look-ahead to the SO. The imbalance price is calculated based on the cost of the actions required to balance the system excluding those required for managing constraints or maintaining system stability (such as reserve or frequency response). The imbalance price paid for being short (system buy price) and for being long (system sell price) are the same. However, parties can submit different bids and offers costs and associated volumes for decreasing or increasing output in balancing actions for the SO.

For energy balancing, the SO should choose balancing actions in order of lowest price which provides a competitive marketplace and keeps the imbalance price reasonably close to the market index price (representing the average price in the wholesale markets). However, in recent times the balancing price has become increasingly volatile and often goes below the wholesale price due to excess supply from renewable generation particularly around midday due to peak solar output as shown in Figure A-2.

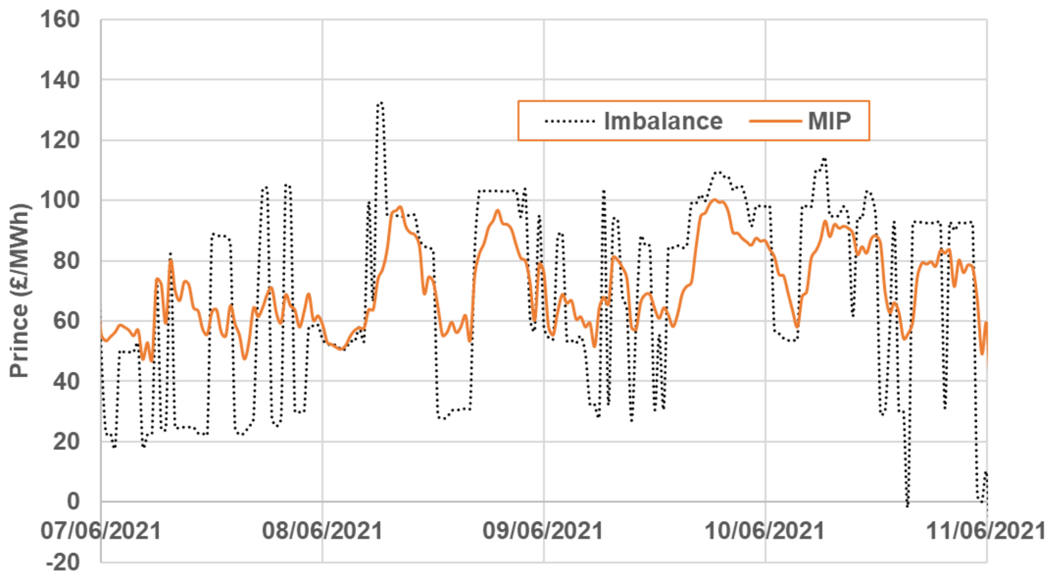

Figure A-2: BM Imbalance price and APX Market Index Price (MIP) for 7th to 11th July 2021; data [179]

A.1.3 Ancillary Services

The national grid operates numerous ancillary service markets to maintain system stability and to provide reserve. Ancillary service markets being accessed by DERs include firm frequency response (FFR), demand turn-up and short term operating reserve (STOR). Minimum sizes for participation are 3 MW for STOR, 1 MW for firm frequency response (FFR) and 1 MW for demand turn up which can be aggregated from units of 0.1 MW or larger. BM units contracted to provide these reserve services cannot participate in the BM or provide more than one service during contracted windows. Most ancillary services are contracted a month or more ahead which historically has prevented intermittent renewables from tendering [14].

The GB electricity system is heavily regulated, and the complexity of the regulations is a major barrier for smaller parties such as DERs to participate and adds to the challenge of coordinating the wholesale and balancing markets outlined above, the following is a brief overview of this extensive topic.

A. 2. Regulation of the GB Electricity system

The GB transmission network is owned by 3 companies: National Grid Electricity Transmission (NGET) in England and Wales, Scottish Power Energy Networks (SPEN) in southern Scotland and Scottish and Southern Electricity Networks (SSEN) in northern Scotland [218]. The Distribution system is divided into 8 regions owned and operated by 6 Distribution Network Operators (DNOs) [218]. The grid infrastructure which transports electricity in the GB is a natural monopoly which relies on regulation (provided by the Office of Gas and Electricity Markets – Ofgem [170]) to ensure value to customers. Ofgem are also responsible for regulating the retail and wholesale electricity markets to ensure competition, and prevent market power being exercised, which is important given that the 'big 6' energy companies supplied close to 70% of households in the UK [221] and provided 65% of electricity generation in 2015 [222]. This vertical integration of generation and supply, which are supposed to be served by separate competitive markets, requires tight regulation and the 'big 6' are required to publish the Consolidated Segmental Statements (CSS) which provide an annual set of accounts of retail and generation activities in the GB retail gas and power markets [223].

Any generator, supplier or trading party wishing to participate in the wholesale market, or hold a generation or supply licence, must be a signatory to the BSC which is a legal document defining requirements for participation in the balancing mechanism and for settlement of imbalance. Furthermore, users wishing to connect to, and use, the NGET extra-high voltage (EHV) system, in other words any large generator or supplier that is not exempt, must adhere to the connection and use of system code (CUSC). The CUSC requires the payment of use of system charges including the balancing services use of system (BSUoS) charge and transmission network use of system (TNUoS) charges. These codes and charges are extremely complex, and require significant expertise and collateral to become signatories.

Distribution Use of System (DUoS) charges are currently levied by the DNOs on suppliers who then add these costs to consumers electricity bills (making up 16% of domestic bills in 2013 [224]) based on their deemed use of the local distribution network. The charges cover the costs of operating and maintaining the grid between the Grid Supply Points (GSPs - connection points to the transmission system) and end users, this includes the cost of overhead lines, underground cables, transformers, and substations. These charges are calculated by the DNOs based on the Common Distribution Charging Methodology [225] (CDCM) for LV and medium voltage (MV) lines. For demand users, the DUoS is made up of a fixed charge (regardless of usage), a capacity charge related to import capacity, reactive power charges and variable unit charges which for half hourly metered customers vary with time 'zones'

[226]. The most expensive time zone is 16:00 - 19:00, Monday - Friday, known as the 'red' zone and companies on flexible tariffs can reduce their DUoS charges by reducing consumption at this time. Distributed generators can have negative DUoS charges meaning they are paid for using the distribution system. Distributed generators can negotiate with the supplier for a share of avoided transmission charges, transmission losses and distribution losses [227] as well as a share of negative DUoS charges when applicable.

The regulations for distribution, transmission and competition in wholesale electricity markets are continually evolving to accommodate the increasing decentralised supply of electricity from a larger number of smaller players. The GB electricity system is highly complex, with numerous national wholesale and ancillary service markets as well as more recent regional DSO flexibility markets, not to mention the regulatory codes and standards to ensure safe and reliable supply.

A. 3. Decentralisation of supply

While the decentralisation of electricity generation is proceeding at pace, regulations and market operators are struggling to keep up. In GB, the electricity trading arrangements still favour large players and significant financial backing is required to participate in the wholesale and balancing markets [228]. The most common route to market for smaller DERs is through aggregators and suppliers using Power Purchase Agreements (PPAs) [228]. Micro generation (e.g., home solar) has historically benefited from feed-in tariffs however these have been cut for new installations, and were replaced with supplier export tariffs with a minimum rate of 0 p/kWh in early 2020. There is increasing participation of DERs in the national ancillary service and balancing markets via aggregators, however, there is very little coordination between the DSO and TSO or management of the effects of DERs on the distribution networks (such as congestion management).

Existing GB market mechanisms, both for wholesale supply of electricity and for ancillary services, can prove to be a barrier to entry from the DERs perspective. However, routes to market are opening up for DERs, including the following recent changes to the GB market arrangements:

- Aggregators have been increasingly providing ancillary services to the TSO, and began participating in the BM in August 2018.

- DSO flexibility markets are under trial in most distribution network regions using the Piclo flex platform [50]. These flexibility markets are predominantly for peak demand shaving to defer network reinforcement.
- The national markets are slowly evolving with changes including project TERRE (Trans European Replacement Reserves Exchange) [229], which could provide more opportunities for aggregated DERs in the BM.
- Since April 2017, all non-domestic customers within Elexon profile class 5-8 (small businesses and commercial) are settled based on half hourly meter readings.
- NGESO added a distributed resource desk in January 2019 which increased the DER capacity in the BM market by 179% to 145 MWs by April 2019 [230].

The developments above are extremely important for increasing participation of DERs in GB electricity markets, both at distribution and transmission level. This increases the requirement for the coordination of access to these DERs between the DSO and TSO and management of possible distribution network congestion as a result of increasing levels of DERs. As a result of project TERRE and the introduction of the 'Virtual Lead Party', DERs will no longer be required to become a licenced supplier to access the BM [231]. The move towards half hourly settlement means demand side DERs can participate actively in distribution and national markets, and in the future this could be extended to domestic level with the installation of smart meters [232]. As the share of DERs in the electricity mix rises, they will be increasingly be relied upon to provide flexibility to the DSO and TSO for ensuring stable operation [233]. From the industry perspective, there has been progress towards decentralised trading of electricity, such as the ongoing DSO flexibility market trials [71], [79], [80]. However, the tools required to actively manage distribution network congestion and maximise penetration of DERs are still very much in their infancy. Furthermore, existing tools for the coordination of DSO and TSO markets have not been fully adopted, and will be required for widespread implementation of DSO flexibility markets.

A major challenge in the application of congestion management and DSO-TSO coordination tools is the complexity of existing deregulated electricity systems which have multiple actors, regulatory codes and markets running in parallel. Any tools developed will have to integrate within complex electricity system structure

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