School of Electrical and Electronic Engineering

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Interactions between demand side response, demand recovery, peak pricing and electricity distribution network capacity margins.

A thesis presented for the degree of Doctor of Philosophy

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Abstract

The operation of the electricity system is subject to: charges comprised of energy, capacity, use of system, peak demand and balancing components; payments for services that influence the timing and magnitude of demand; and regulatory and physical network constraints. This work explores the interactions of these characteristics in the GB system.

The revenue flows associated with energy demand, balancing and use of system charges are mapped for generators, transmission and distribution network operators (TNO and DNOs), system operator (SO), electricity retailers and electricity users.

Triads are part of the transmission network use of service charges and are a form of peak demand pricing. The cost-benefit of Triad avoidance using emergency standby generation is evaluated. Demand Side Response (DSR) provision by commercial electricity users on the network is modelled and simulated. The research determines the impacts of DSR timing, location and penetration level, demand recovery and incidence of Triad periods.

A suite of software models was developed including: network demand agents which can be populated with demand profiles and include a model of energy recovery; an interface to *Matpower* [1] to allow for time-domain based power flow calculations and a model of Short Term Operating Reserve (STOR) which synthesizes calls at representative dates and times. The network demand agents are linked to bus-bars on a network model. The software suite is used to investigate the impacts of STOR provision by demand reduction with and without energy recovery on Triad demand using a Monte Carlo simulation. The total cost benefit of participation in STOR is evaluated. It is also used to conduct time-aware power-flow analysis on a distribution network model with STOR provision by demand reduction. The impact on network capacity headroom is quantified.

The cost effectiveness of using standby generation for Triad avoidance was found to depend on the cost of the grid compliant connection. For a payback time of 4 years or less, with the size of generator considered, the grid compliant connection would have to cost less than £5,600.

The probability of decreased Triad demand due STOR provision by demand reduction with energy recovery is up to 4 % for the parameters considered. This compares to a probability of up to 1.6 % that the Triad demand would be increased. The most likely outcome is that Triad demand remains unaffected. The total cost benefit of STOR provision by demand reduction for the 1st percentile may be negative compared to not participating.

The impact of DSR provision by demand reduction with energy recovery on the distribution network capacity overhead varies significantly with time of day and with the distribution of DSR over the network. For evenly distributed DSR, demand recovery peaks greater than 40 kW cause a reduction in capacity overhead. However, for a case where the DSR is not evenly distributed the capacity overhead does not decrease for recovery peaks less than 800 kW.

Declaration

I hereby declare that this thesis is a record of work undertaken by myself, that it has not been the subject of any previous application for a degree, and that all sources of information have been duly acknowledged.

Parts of this thesis have been published by the author as detailed below.

The work in *Chapter 7 Cost benefit analysis of using standby generation for Triad avoidance* is largely based on: "Use of standby generation for reduction of transmission network charges for half-hourly metered customers," by C. Mullen, P. C. Taylor, V. Thornley, and N. S. Wade, presented at 49th International Universities Power Engineering Conference (UPEC), Cluj-Napoca, 2014

The work in *Chapter 8 STOR and Triad coincidence* is an elaboration of "The impact of the coincidence of STOR and triad events on STOR provider's net-income considering load recovery characteristics," by C. Mullen, N. S. Wade, O. Olabisi, and P. C. Taylor, presented at the CIRED, Helsinki, 2016.

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Chapter 1. Introduction to the thesis

The work in this thesis concerns interactions between: actors in the electricity network; physical network properties e.g. asset ratings and connection topology; demand profile; billing structure; Demand Side Response (DSR) profiles and timings; DSR payment structure and value. The actors considered in this work are: the electricity user; the Transmission Network Operator (TNO); the System Operator (SO) and the Distribution Network Operator (DNO).

The introductory chapters describe different aspects of the GB electricity system. First in Chapter 2, the operation and regulatory framework of the GB electricity system is described. This also includes mapping of the revenue flows between different actors.

Next, in Chapter 3 commercial demand profiles are described starting with GB total demand profiles and comparing the contribution of commercial demand averaged by season and month respectively. Commercial demand is broken down by sector. Then an example of demands at a primary and its secondary transformers are given in order to illustrate the diversity of demand. The concept of demand smoothing due to diversity is explained.

Then the term *Demand Side Response* as used in this work is defined in Chapter 4. Network benefits and applications of DSR are described. The characteristics of DSR from a demand (electricity user) point of view are described.

The characteristic of energy rebound after demand reduction, which affects demands with inherent storage, is described with results from other authors. This characteristic is important in this work as energy recovery in combination with DSR can create a lack of demand diversity, as seen in Chapter 10.

Triads and DSR service types, including DNO requirement for DSR are outlined in Chapter 5, including market data and value where possible. The potential of DSR in the context of the commercial sector is described and quantified where possible. This includes a discussion on commercial demand profiles and sub-load types and particular reference to short term operating reserve (STOR) and Time of Use (ToU) tariffs. The factors affecting participation with DSR were described with particular emphasis on the barriers from the point of view of: the energy users; aggregators; and DSR procurers

It was necessary to build a suite of software models in order to analyse various interactions which make up the work in this thesis. For example STOR was modelled in order to produce sets of modelled STOR calls for a Monte Carlo analysis of the coinciding of STOR and Triad. The models are also used to give bill cost information. An overview of the software suite is given in Chapter 6 and more detail on specific models is given in the relevant chapters that follow.

The use of an emergency standby generator for the mitigation of Triad charges is explored in Chapter 7. This shows the benefit to a commercial electricity user, in terms of bill charges, of taking demand side actions.

The coincidence of STOR with Triad periods is analysed in Chapter 8 using the software models developed in order to show the probabilities of the interference of the two and to assess the likelihood of this being a positive or negative cost benefit to the provider of STOR. This potential coincidence and its consequences are interesting because the STOR service and the Triad charge come from different actors in the system: the SO and the TNO. The software model for STOR is described in more detail in this chapter.

The C2C ("Capacity to Customers") project was a Low Carbon Network Fund (LCNF) project which explored the use of DSR and new curtailable contracts in order to increase the distribution network capacity. The method and modelling for the project is described in Chapter 9. The chapter also describes the software models developed for this work in order to interface and extend the C2C work, by the inclusion of time-based demand profiles. The time dimension is important for this work as it means that demand diversity is included in the analysis.

The effect of DSR by demand reduction with demands exhibiting energy recovery is analysed in Chapter 10. This uses the software models described in Chapter 6 and Chapter 9 to explore potential conflict between the SO-called DSR service and DNO assets capacity. The chapter describes in more detail the software models and algorithms used.

The overarching themes of this work are: how a DSR value stream for one network actor may modify the value to another actor and the importance of a potential lack of diversity due to DSR. The work develops a suite of software models to investigate these themes using time-based demand profiles connected to a distribution network model.

The research questions in this work are:

- What are the financial benefits to an electricity bill payer of using existing emergency generation to reduce Triad costs and what is the cost in terms of CO_2 emissions?
- What is the value of DSR to an electricity bill payer providing STOR by demand reduction when some of that demand has inherent storage, taking into account the fact that STOR participation may alter demand during Triad periods? What is the probability that demand energy recovery increases or decreases the cost of Triad to the STOR provider?
- How do the specific characteristics of DSR by demand reduction affect the distribution network capacity? How does the scale of DSR by demand reduction that has inherent storage and the location of the providers impact on this?

Chapter 2. GB electricity system: infrastructure and roles

2.1. Introduction

This chapter describes the electricity system in terms of the roles and responsibilities of the various organisations and actors within the system. The revenue streams between the actors are illustrated and the regulatory system surrounding these is touched on. Diagrams of the revenue flow are synthesised.

First a brief overview of the systems of trading, balancing and settlement of electricity on a half-hour (HH) basis is given. More detail on the regulatory structure and the financial processes behind them is given in the later sections. This chapter also presents the revenue flows within the GB electricity system, that have been mapped by the author.

The electricity network was privatised in 1990 [2] and runs as a system of highly regulated private companies. It is regulated by Ofgem, who state that the main themes of it's activity are: promoting value for money; promoting security of supply; promoting sustainability and delivering government programmes.[3].

The main actors in the electricity system are:

- TNOs
- SO
- DNOs
- Electricity Users
- Retailers
- Settlement Arbitrator (Elexon)
- Electricity Generators
- Distributed Generators
- Aggregators
- Non-Physical Traders (NPTs)

The TNO consists of: National Grid Electricity Transmission plc (NGET) in England and Wales; Scottish Power Transmission Limited for southern Scotland; and Scottish Hydro Electric Transmission plc for northern Scotland and the Scottish islands groups. The SO is National Grid Electricity Transmission plc (NGET). The distribution networks exist in fourteen licenced regions are managed by six different companies: Electricity Northwest (ENW); Northern Powergrid (NPG); Scottish and Southern Energy (SSE); Scottish Power Energy Networks (SPEN); UK Power Networks (UKPN); and Western Power Distribution (WPD). Electricity users are the consumers of electricity. Retailers (also know as “suppliers”) buy electricity in advance of supply and sell it on to electricity users. The settlement arbitrator (Elexon in the GB system) compare what the generators and retailers said they would produce or consume against the actual volumes and calculate the price for the difference for each actor in a process known as imbalance settlement [4]. They work according to the BSC. Electricity generators means producers electricity connected to the transmission network and bound by the BSC. They sell their electricity ahead of production to retailers. Distributed generators refers to electricity producers connected to the distribution network or ‘behind the meter’. It is not mandatory for them to sign up to the BSC. Aggregators provide DSR services from their portfolio of electricity users. They act as an intermediary between the individual electricity users and the DSR procurer. In this way they isolate the electricity users from the contractual complexities of providing DSR. They may also reduce the financial risk to the electricity user of non-compliance by allowing less stringent participation rules. Non-physical traders are individuals or companies (such as banks) who buy and sell electricity for profit but have no means of generating and no requirement to consume the electricity bought and sold [4].

2.2. Electricity system operation overview

There are three main stages associated with every HH period of electricity: trading, balancing and settlement. Electricity trading on a given HH period may take place up until one hour beforehand. This time is known as *gate closure*, see Figure 1. Electricity cannot be stored economically, therefore the generation and demand of electricity must be continuously managed by the SO. Gate closure marks the start of the balancing process which is managed by the SO. At the end of a HH period, the imbalance settlement commences. This is conducted by Elexon, who reconcile the differences between contracts for buying or selling electricity, and the actual energy generated or consumed during that half hour. This process takes several months.

The three stages, trading, balancing and settlement are described in more detail in the sections that follow.

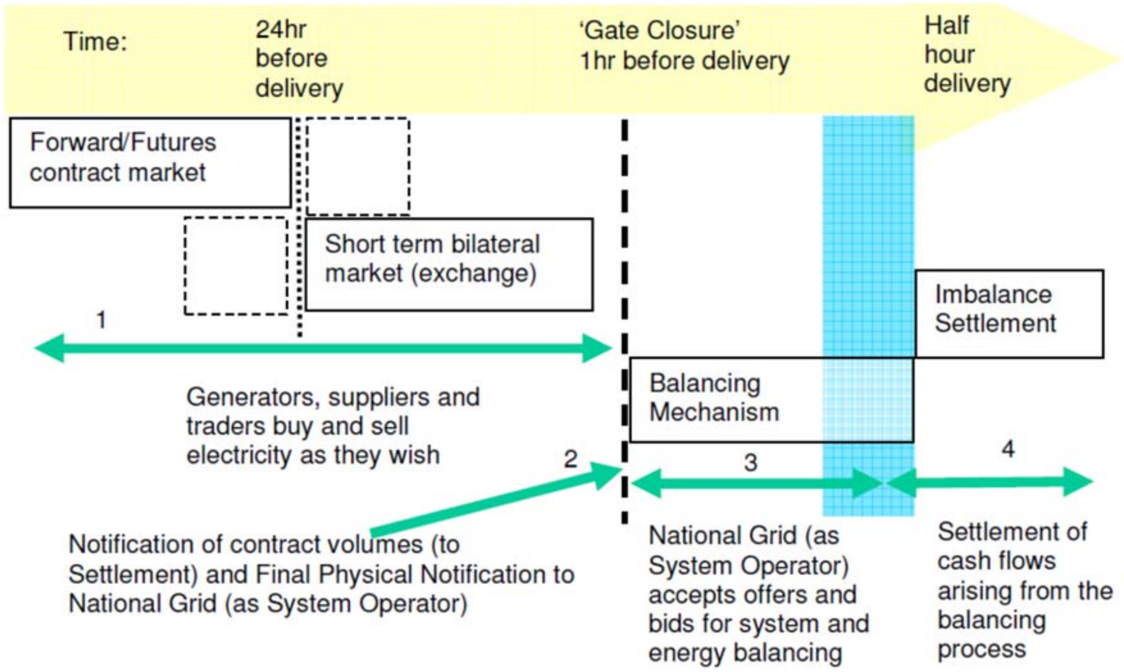


Figure 1 The timeline for trading, balancing and settlement for a single half-hour period of supplied electricity [5]

2.2.1. Stage 1: Before gate closure

Electricity is bought via bilateral contracts or on the wholesale market. The wholesale market is a competitive market where suppliers and electricity users can buy electricity from various companies including NPTs such as Investment Banks. Contracts for base load are sometimes made years in advance, whilst exchange trading is used for fine tuning the base demand and to add shape to the supply [6]. Electricity trading is discussed in more detail in section 2.3.1.

2.2.2. Stage 2: After gate closure and up to the end of delivery

The SO must manage the energy balance (supply and demand), resolve transmission network constraints in a way that ensures value for money.

This is achieved by forecasting demand for each settlement period and comparing it with the data submitted by generators so as to determine whether there is likely to be surplus or deficit of electricity in that settlement period. This data is used by the SO to plan how to undertake the balancing of the system. The SO can call on a variety of balancing services, which operate at different timescales, in order to balance the supply and demand. These services are described in more detail in section 2.3.3.

2.2.3. Stage 3: After HH delivery

After a HH period has passed the imbalances between different organisations operating in the electricity system must be reconciled. This settlement is governed by the BSC and carried out by Elexon. It is based on HH time periods (metered or profiled) and is used to account for:

- differences between retailer forecast versus actual consumption
- differences between generators contracted electricity generation versus it’s actual generation
- problems with the transport of electricity
- Non Physical Traders that have bought more energy than they have sold (note this would be highly undesirable for the trader).

2.3. Regulatory framework and revenue mapping

The sections that follow relate to and expand on information in the previous sections by identifying the governing regulations and mapping out the flows of revenue in the electricity system. These revenue flow diagrams are split into four groups:

- Energy trading
- Use of system costs
- Balancing costs
- Settlement costs

For each revenue flow diagram all of the organisation are shown regardless of whether they are part of that particular revenue flow or not. This makes it easier to compare one diagram to another. Table 1 shows the key to the revenue flow diagrams. The abbreviation *AEO* in the diagrams stands for *Authorised Electricity Operator*. This means *“Any person (other than the DNO in its capacity as an operator of a Distribution System) who is authorised to generate, participate in the transmission of, distribute or supply electricity.”* [7]

2.3.1. Revenues associated with energy trading

Electricity is traded either on an exchange or via a bilateral contract with a generator. The bilateral contract is a direct contract between a generator and an electricity user or retailer, and is known as a power purchase agreement (PPA). A supplier may enter into a contract for electricity years in advance of delivery using a PPA. Larger electricity users may also enter into a PPA although the contracts can be complicated to set-up. The advantage may be a reduction in price or that renewable energy can be sourced. In this case the user then ‘sells on’ the electricity to its own retailer who credits the end-user’s electricity account with the corresponding amount of electricity, as shown in Figure 2.

An exchange is most often used for fine-tuning base load and adding shape to the supply. The exchange matches buyers with sellers at the same price point and is anonymous. There are two exchanges in the UK EPEX SPOT (formerly known as APX Power) and Nord Pool.

	An arrow represents a flow of revenue. The organisation at the arrow head has revenue income from the organisation at the tail of the arrow
	A box indicates an organisation in the system, including the electricity user.
	An octagon represents a process which includes: markets, regulatory components and service types
	A lozenge shape indicates a specific charge/payment type

Table 1 Key to the revenue flow diagrams

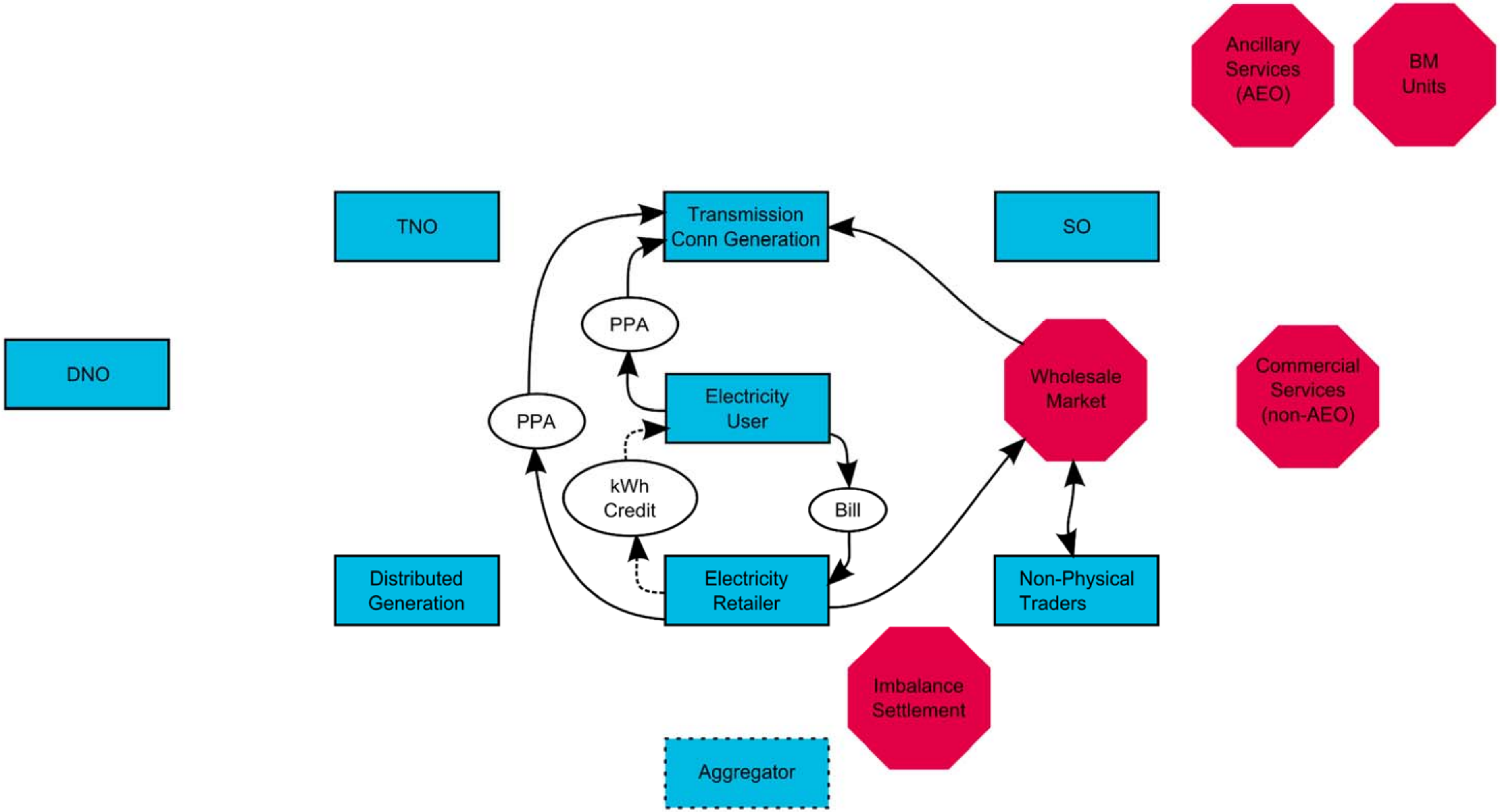


Figure 2 Revenue flows associated with energy trading

2.3.2. Revenues associated with use of system charges

Use of system charges apply to the use of the transmission networks, use of distribution networks and the balancing mechanism. The transmission network and balancing mechanism charging regimes are defined by the Connection and Use of System Code (CUSC) whilst the distribution network charging regime (see section 2.3.2.2) is governed by the Distribution Connection and Use of System Agreement (DCUSA). It should be noted that although the Transmission Network Use of System (TNUoS) charges and the balancing mechanism use of system charges are both regulated by the CUSC, they apply to different parts of National Grid: the asset owner (TNO) and the SO. The balancing use of system charges are described in a later section while this section relates to asset use (both TNO and DNO).

The revenue flow for asset use of system charges for both TNO and DNO is shown in Figure 3. They are described separately in the following sections according to the regulations that govern their implementation.

2.3.2.1. Transmission Network use of system charges (TNUoS)

Section 14 of the CUSC [8] covers charging methodologies including the charges for:

- TNUoS
- the Balancing Service Use of System (BSUoS). See section 2.3.3.

Figure 4 shows the main areas relating to TNUoS charges (CUSC sub-sections 14.14 to 14.28). The tariffs are set using electricity transport modelling. Charges include:

- Demand charges
- Generation charges
- Energy consumption for short term capacity

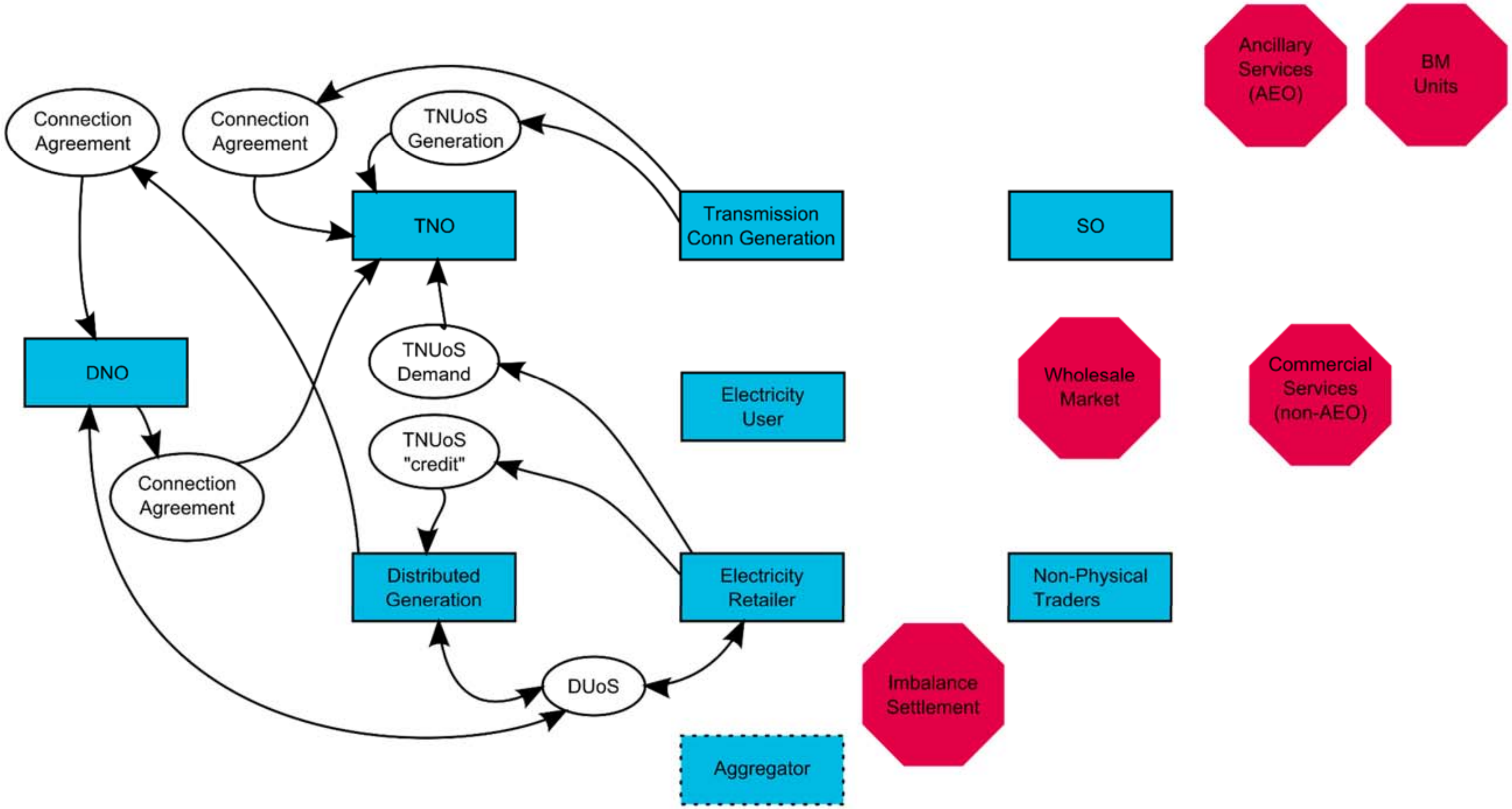


Figure 3 Revenue flows associated with use of system charges

Demand charges

The demand charges for the TNUoS are based on either a Chargeable Demand Capacity (CDC) or a Chargeable Energy Capacity (CEC).

For an electricity retailer the CDC applies to the average of the HHM demand during the Triad periods (£/kW tariff). The CEC applies to NHM energy demand over the period 16:00 to 19:00 for every day (p/kWh tariff) as defined by their profile class. These charges are passed onto the energy user, however they are not always explicitly detailed in the bill breakdown.

Generation charges

For power stations with a bilateral connection agreement, the CDC applies to the average net import during each Triad.

For Exemptible Generation and Derogated Distribution Interconnectors with a bilateral embedded generation agreement the CDC is based on the average metered volume.

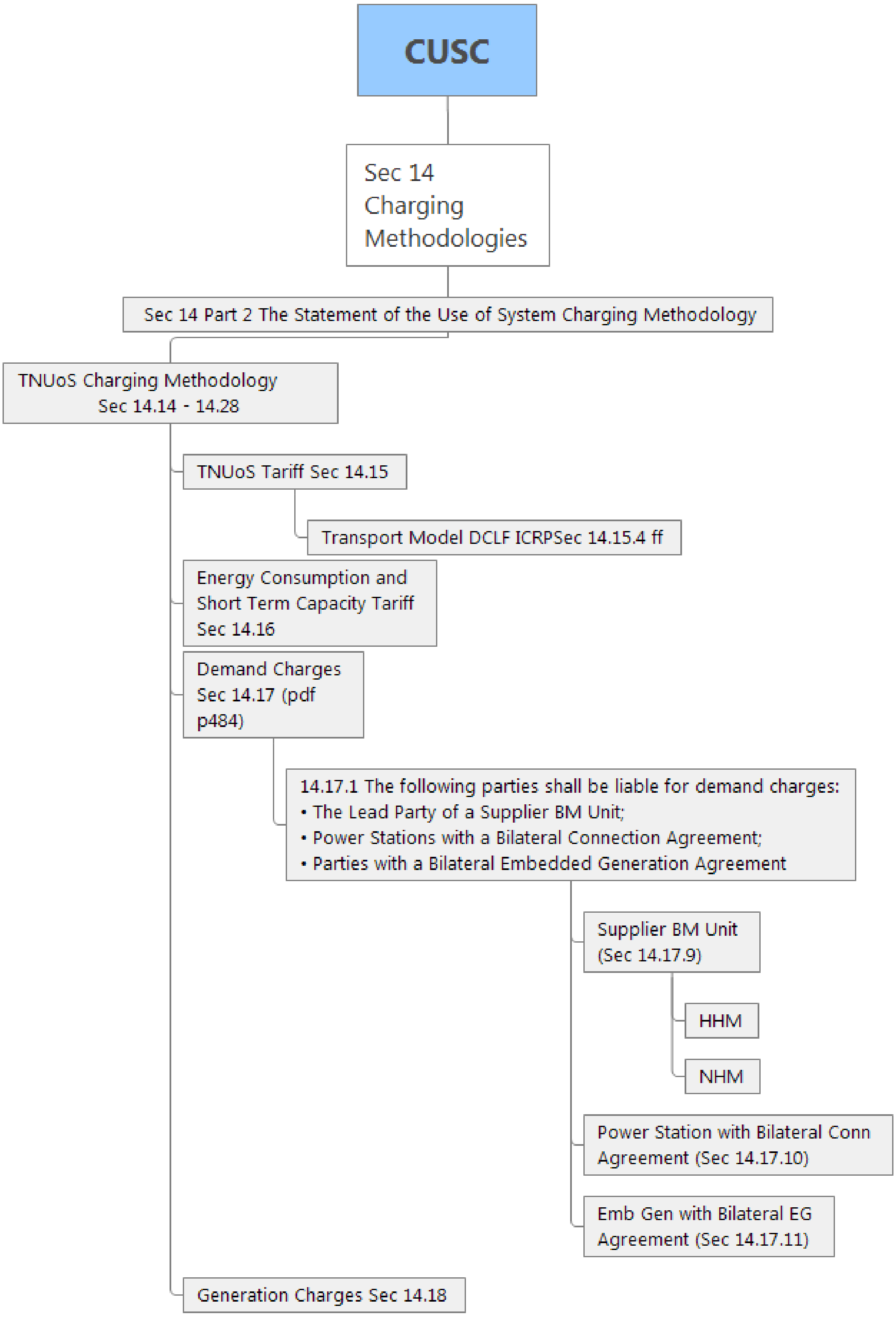


Figure 4 CUSC section 14 subsection TNUoS

2.3.2.2. Distribution network use of system charges

Launched in 2006 the DCUSA replaced numerous bilateral contracts. It defines how DNOs charge generators and suppliers for use of the distribution network. It is a multi-party contract involving: DNOs, suppliers, the Offshore Transmission System Operator (OTSO) and generators. DG parties have obligations under other industry agreements and agree to accede to DCUSA to meet those obligations.

DUoS

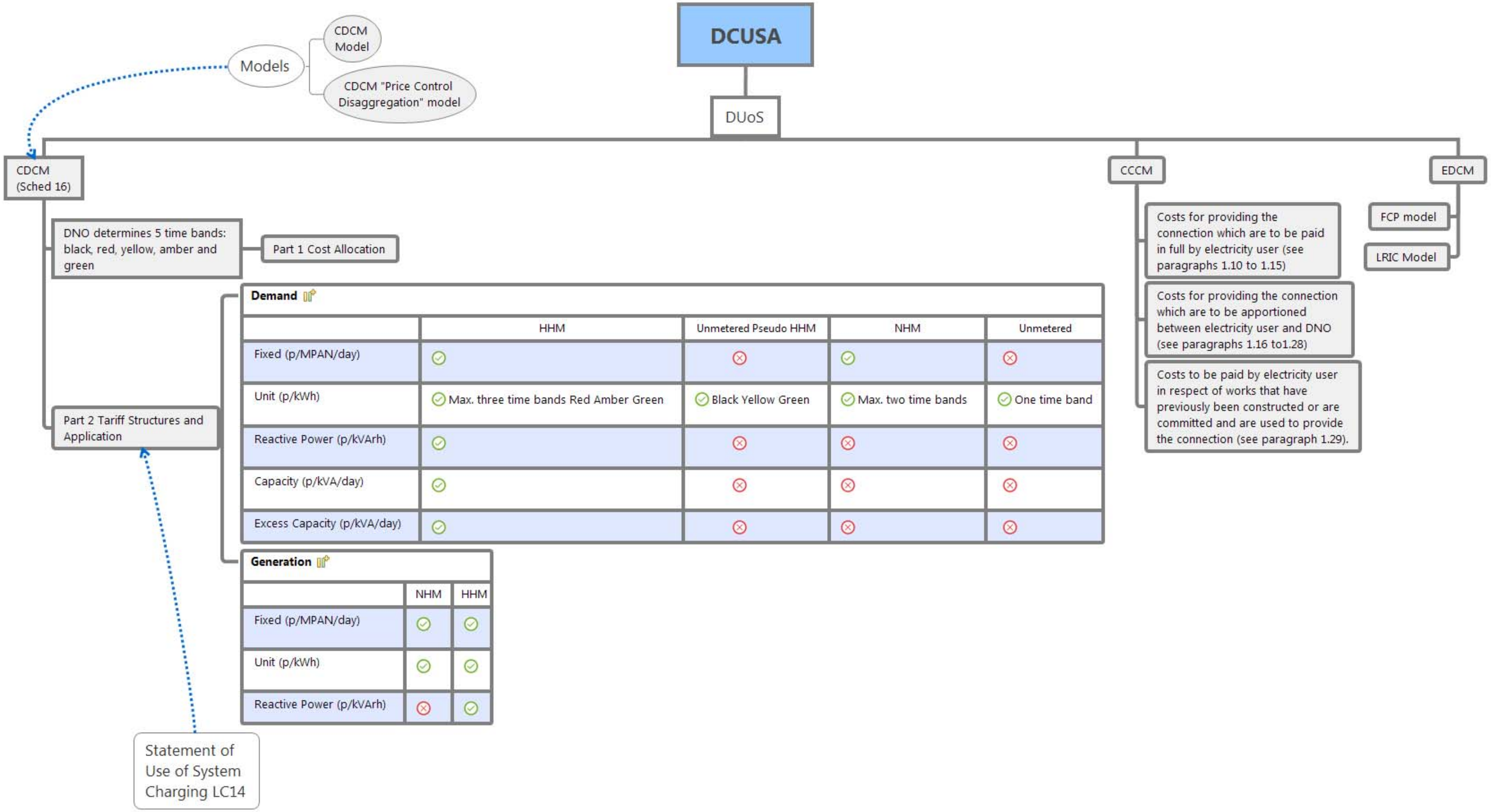
The DUoS tariff consists of three elements as shown in Figure 5:

- the Common Distribution Charging Methodology (CDCM)
- the Extra High Voltage Distribution Charging Methodology (EDCM)
- the Common Connection Charging Methodology (CCCM)

The DNOs are required to populate the CDCM model which is defined in schedule 16 of the DCUSA The CDCM includes tariffs for demand and generation which are published by DNOs in their *"statement of use of system charging"* which is required under the Standard Licence Condition 14 (LC14). For HH metered demand users there are up to three ToU tariffs relating to the kWh charge in the DUoS.

The CCCM covers the apportionment of connection costs between the DNO and the party that wishes to connect.

The EDCM covers the charging methodology for extra high voltage connections. There are two costing models: Forward Cost Pricing (FCP) and Long Run Incremental Cost (LRIC) used by different DNOs.



Demand

	HHM	Unmetered Pseudo HHM	NHM	Unmetered
Fixed (p/MPAN/day)	✓	✗	✓	✗
Unit (p/kWh)	✓ Max. three time bands Red Amber Green	✓ Black Yellow Green	✓ Max. two time bands	✓ One time band
Reactive Power (p/kVArh)	✓	✗	✗	✗
Capacity (p/kVA/day)	✓	✗	✗	✗
Excess Capacity (p/kVA/day)	✓	✗	✗	✗

Generation

	NHM	HHM
Fixed (p/MPAN/day)	✓	✓
Unit (p/kWh)	✓	✓
Reactive Power (p/kVArh)	✗	✓

Figure 5 Structure of DCUSA

2.3.3. Revenues associated with balancing

National Grid acting as the SO must balance the network in terms of both energy flows (matching supply and demand) and keeping it operating within statutory limits. They must also ensure that it operates economically. National Grid is paid for balancing from the BSUoS charges. These charges apply to all parties that are subject to the CUSC and charges are "based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period" [9]. Figure 6 shows where the BSUoS sits within the CUSC.

Although gate closure marks the beginning of the balancing mechanism, the SO may also participate in the wholesale market before gate closure: *"In meeting forecast energy requirements at minimum cost National Grid trade energy related products forward in time (i.e. in advance of the Balancing Mechanism)"*. [10]. These products could be:

- Power Exchange Trades
- Forward Energy Trades
- Energy Balancing Contracts

BM units must submit data, known as *"Physical Notifications"* before gate closure. The Physical Notification includes the expected generation/demand. At gate closure the Physical Notification becomes the Final Physical Notification (FPN). The SO manages the energy balance (supply/demand), as well as the system constraints and commercial aspects of energy flow using a range of balancing services:

- Ancillary Services
    - System Services
    - Commercial Services
    - Other Services
- Bid/Offer acceptances (via Balancing Mechanism Units, governed by the BSC)
- Other Services

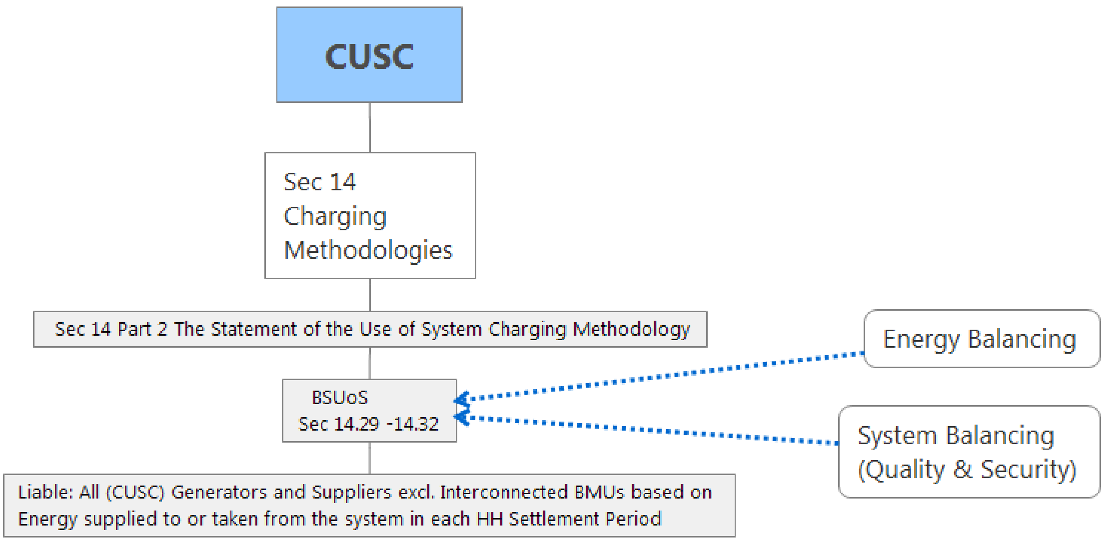


Figure 6 CUSC section 14 subsection BSUoS

2.3.3.1. The Balancing Mechanism

The balancing mechanism is the process by which the SO manages the balance of supply and demand. It is a "short term market for physical energy where suppliers or generators can make offers to sell, or bids to buy" [11]. It is based on balancing mechanism (BM) units:

"BM Units are units of trade in the Balancing Mechanism They are used in the BSC to account for all energy that flows on or off the Total System, which is the Transmission System and the Distribution System combined. A BM Unit is the smallest grouping of equipment that can be independently metered for Settlement. Most BM Units consist of a generating unit or a collection of consumption meters, and the energy produced or consumed by the contents of a BM Unit is accredited to that Unit." [12]

The types of BM units are:

- T – directly connected to the transmission system (typically generating units)
- E – embedded in the distribution system
- I – interconnector related units. These come in pairs: one for electricity entering the system (Production) and one for electricity leaving the system (Consumption)
- 2 – Supplier's meters. Since there are so many meters, these units are grouped for a particular supplier on a specific Grid Supply Point (GSP). The supplier must have fourteen base supply BM units, one for each GSP Group (even if they don't intend to use them all).
- M – Miscellaneous

The Balancing Mechanism describes the system of Bid-Offer acceptances (governed by the BSC) [4]:

- Offers – a proposal to increase generation or reduce demand
- Bids – a proposal to reduce generation or increase demand

The *offer price* is the amount a company wants to be paid per MWh for an increase in generation or a decrease in demand. The *bid price* is the amount a company is willing to pay per MWh for a decrease in generation or an increase in demand. The Bid Price should be less than the Offer Price. In the case that the SO accepts an Offer Price and then changes its mind the company offering the service still makes a profit of Offer Price minus Bid Price.

The Bid-Offer data indicates that the BM unit can move away from its FPN and sets the prices and volumes for moving away from this point. This is sometimes referred to as a Bid-Offer ladder.

The revenue flow for the balancing mechanism is shown in Figure 7. Here it is indicated that both generators and retailers contribute to payment for the service, allowing the SO to purchase balancing services from authorised electricity operators (licenced) and non-authorised electricity operators. The SO is not limited to the balancing mechanism [4]. Services may be procured from outwith the balancing mechanism, through the wholesale market prior to gate closure and also via ancillary and commercial services.

Ancillary services from authorised electricity operators (AEOs) include: reactive power, frequency response, reserve services and black start. An AEO is authorised to *"generate, participate in the transmission of, distribute or supply electricity"* [8].

Commercial balancing services can be procured from non-AEOs and include STOR, frequency response and fast reserve. Commercial services may or may not be purchased via an aggregator (shown with a dashed border).

Small and medium generator units are exemptible meaning that they do not need a generation licence [12]. This may bring them benefits in terms of charges for TNUoS, and BSUoS.

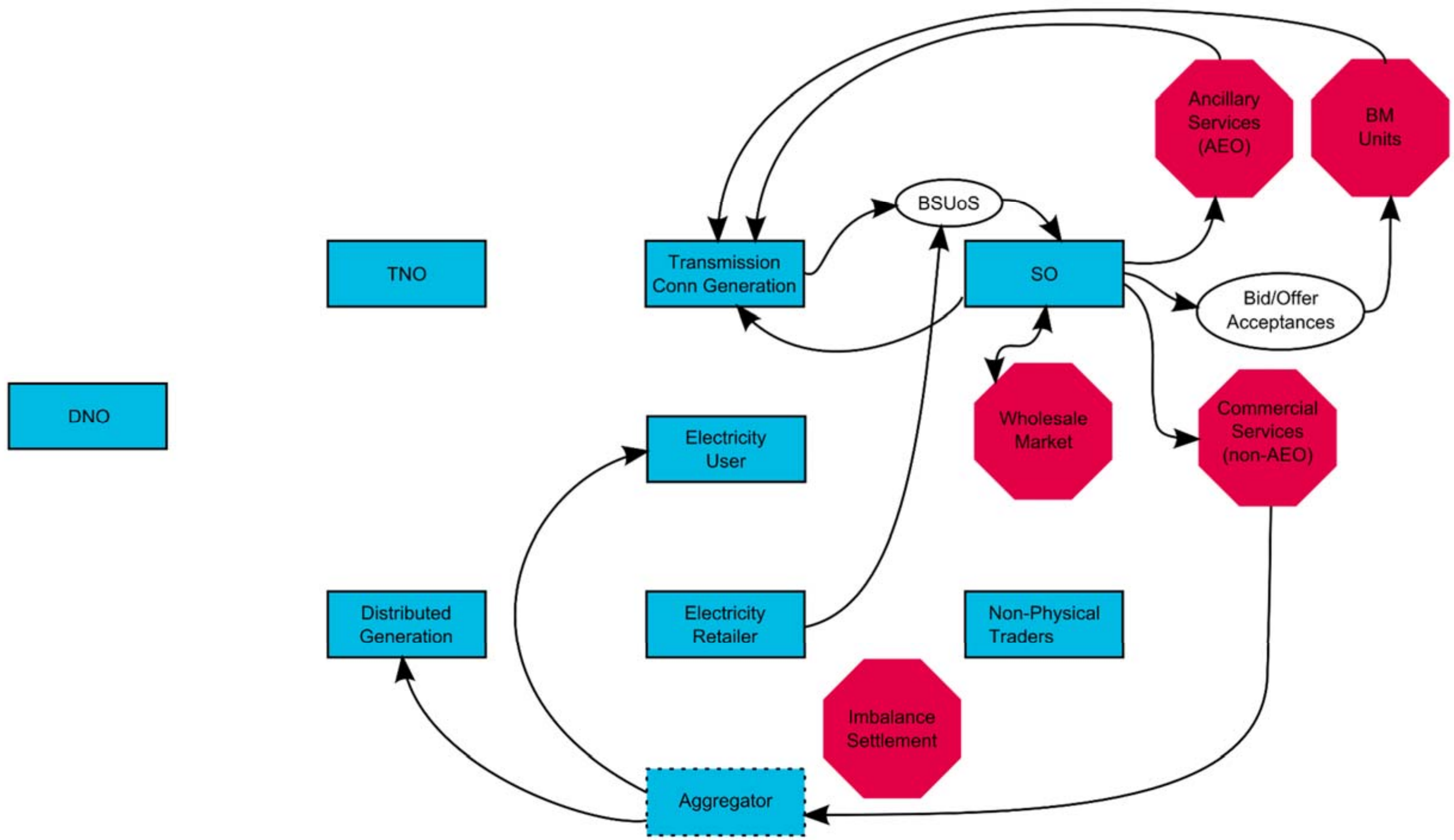


Figure 7 Revenue flows associated with balancing

2.3.4. Revenues associated with settlement [6]

Elexon calculate the energy imbalance volumes taking into account the contracted volumes and the balancing services provided. This gives a figure for a positive or negative imbalance. A negative imbalance means that a party has undercontracted and is short of energy. A positive imbalance means that a party has overcontracted energy. The imbalance is reconciled by effectively imposing the purchase or sale of energy, from or to Elexon, at the System Buy Price (SBP) or System Sell Price (SSP).

All the revenues associated with settlement flow between parties who generated, bought or sold electricity for that HH period. This includes the SO who is able to purchase electricity on the wholesale market, as noted previously. This is shown in Figure 8.

2.3.5. Summary

This chapter has given an overview of the operation of the electricity system in Great Britain including the trade, balancing and settlement. The major regulatory documents have been described and the revenue that passes between the system actors has been illustrated. Ideally the revenue streams of any system should directly relate to the value attached to the product or service offered. In a complex system such as the electricity system this is not always the case. This is seen later in Chapter 10 where DSR called by the TNO could have a significant impact on the infrastructure capacity of the DNO. The revenue flow mapping has a role in understanding and communicating where there is a mismatch between value and revenue.

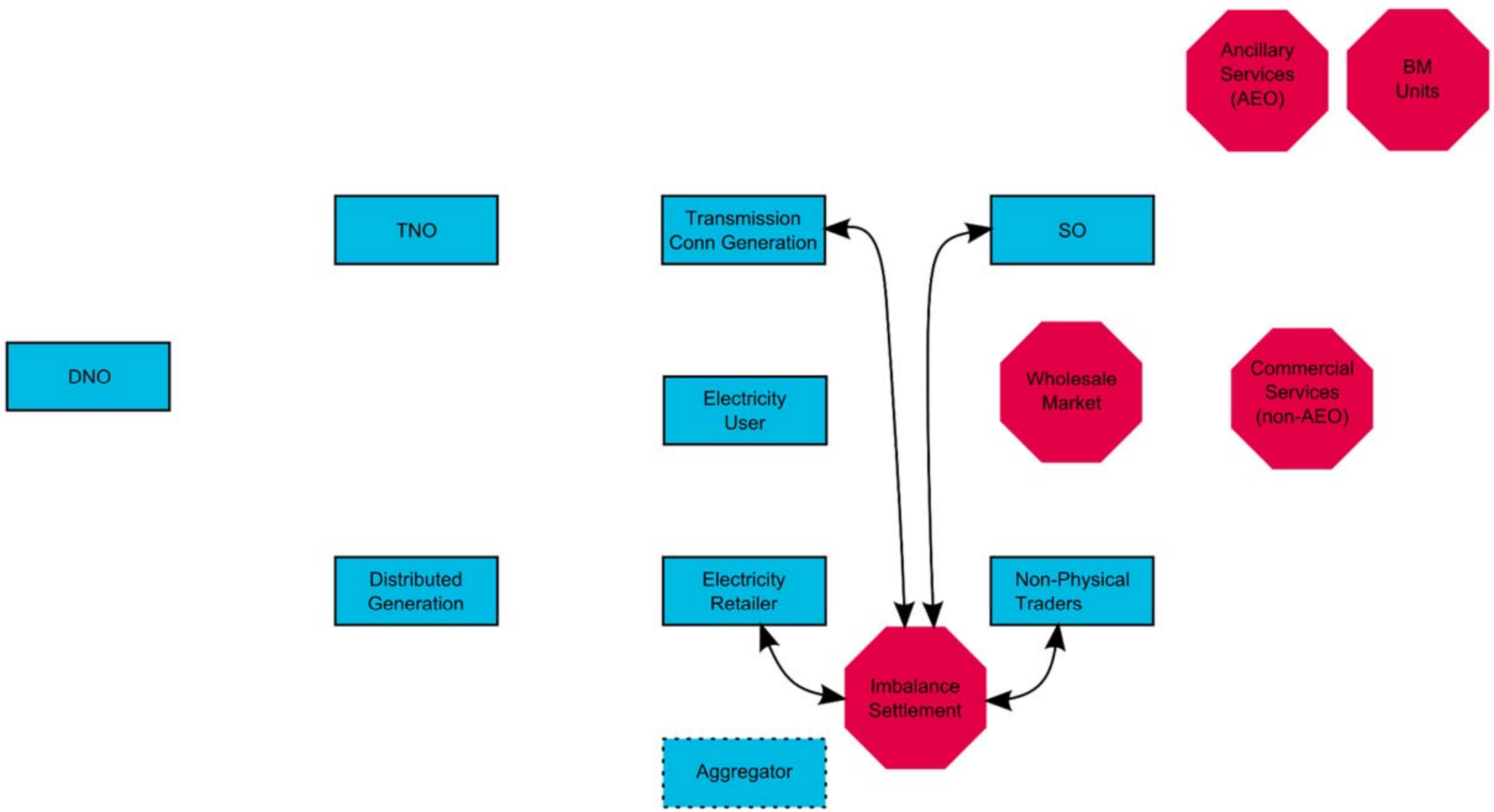


Figure 8 Revenues associated with imbalance settlement

Chapter 3. GB commercial demand

3.1. Introduction

This chapter shows the magnitude and timing of commercial demand in the context of global system (i.e. UK total) demand. The daily demand shapes on a primary substation and its associated secondaries are shown in order to illustrate the increase in demand diversity with localisation (i.e. with decrease in the number of individual electricity consumers considered). Formalised descriptions of this in the literature are described.

The fact that demands are diversified is used in network planning to size the assets appropriately. The concept of diversity is important in this work since DSR by demand reduction may cause a lack of demand diversity if a number of the reduced demands exhibit energy recovery. This is described and analysed in Chapter 10.

3.2. Total GB demand

The typical winter and maximum winter demands profiles given by National Grid [13] for the transmission network are shown in Figure 9. The Typical Winter baseload is around 30GW. It can be seen that the peak demand time is between about 16:30 and 19:30. The maximum demand (typical winter) is about 51GW which is 170% of baseload. In the morning the demand rises to a plateau around 45GW, which is about 150% of baseload.

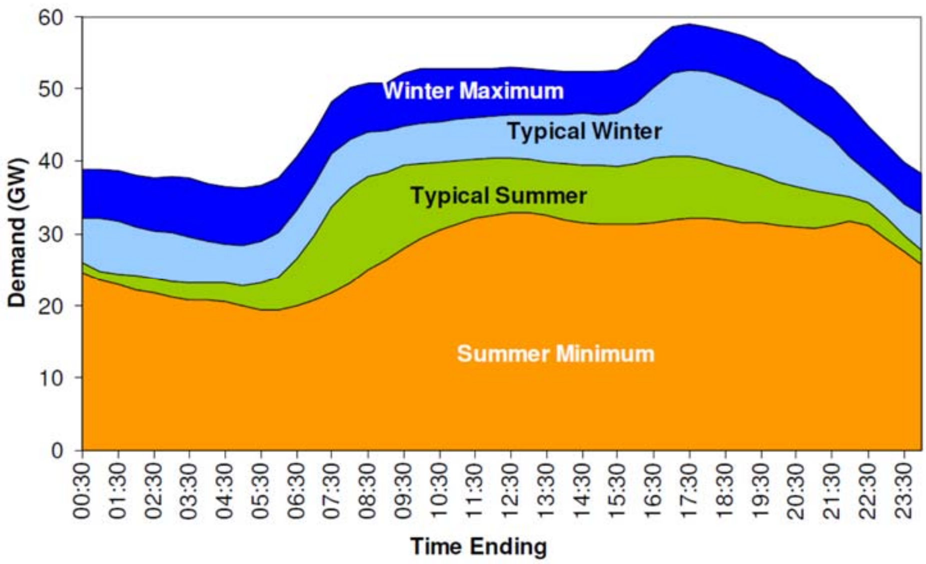


Figure 9 Summer and Winter Daily Demand Profiles in 2010/11 [13]

3.3. Total commercial demand

The GB Electricity Demand project [14] sought to develop an understanding of the electricity demand resource in Great Britain including its economic value and the regulatory issues. The Brattle Group developed a model for the project to quantify the GB electricity demand and use to gauge the potential for demand reduction and peak demand shifting, for the period 2010 - 11 and also toward 2025. The model is solely concerned with the technical scope for demand side reduction, it does not assess commercial, consumer or practical issues.

The model uses data from a number of sources including DECC, Digest of United Kingdom Energy Statistics (DUKES), Elexon and NGET [15]. Some of the DUKES data is HH-metered but a portion is not. In order to include the non-HH metered data it is modelled using the Elexon load profile data

A proportion of the DUKES data used for the model is HH-metered and a proportion is non-HH metered. The non-HH metered data is modelled using Elexon load profile data (see for example [16]) and the total demand for this is 52.9 TWh/year. Given that the total commercial and services load from DUKES is 101.2TWh The Brattle Group assumed that the remainder of the demand after removing the non-HH demand is the HHM data for demands greater than 100kW. This HH-metered demand is assigned in proportion with the Elexon demand across load profiles 6 – 8 (the profiles representing larger demands). Then the demand shape can be assigned to the demand values from DUKES non-HH demand [15].

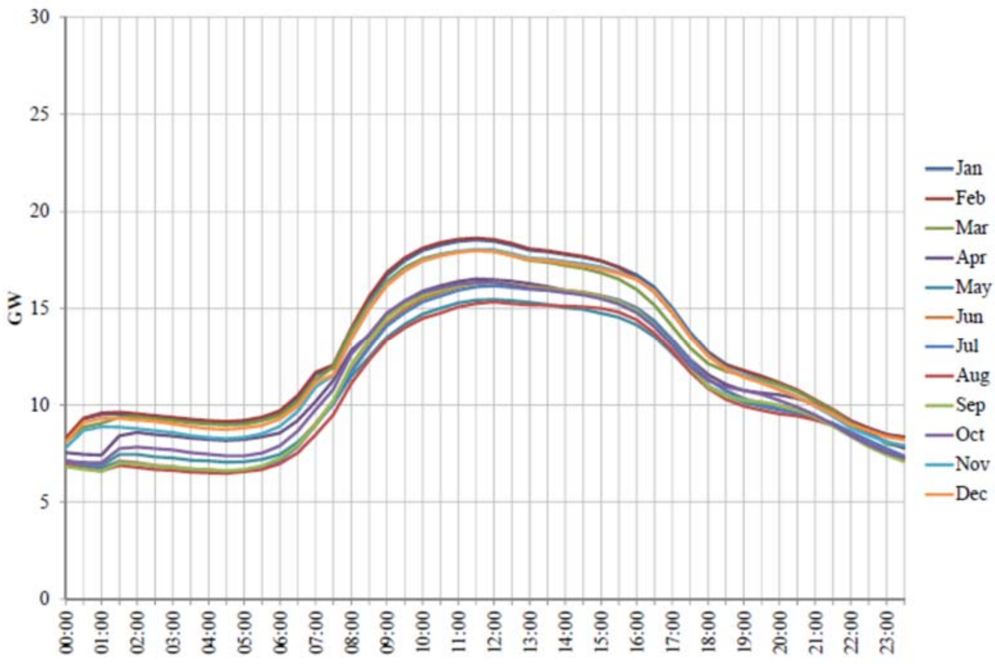


Figure 10 Mean HH Commercial Demand on Weekdays by Calendar Month [15]

Figure 10 shows the modelled HH commercial demand on weekdays. The highest demand months are January and February closely followed by November, December and March. The weekend profile (not shown) is similar in shape but with a lower peak of around 17.5GW for February. The seasonal variation is about 10% compared to 50% for domestic demand [15]. It can be seen that the base demand for January is around 9GW and the demand rises in the morning to around 18GW. This demand plateau is therefore around 200% of baseload which is significantly larger than the same ratio for total network demand. Another feature of the total commercial demand profile is that it does not show an evening peak demand between 16.30 – 17.30.

Using HH meter data Element Energy estimate commercial demand profiles by sector, shown in Figure 11. This suggests that the three sub-sectors which contribute most to peak demands are Retail, Education and Commercial Offices [17]. The results from The Brattle Group and Element Energy are broadly similar and indicate that the commercial demand starts to reduce at around 16:30.

Grünewald and Torriti state that in the UK commercial sector electricity demand is dominated by lighting, but heating, cooling and catering also contribute significantly [18]

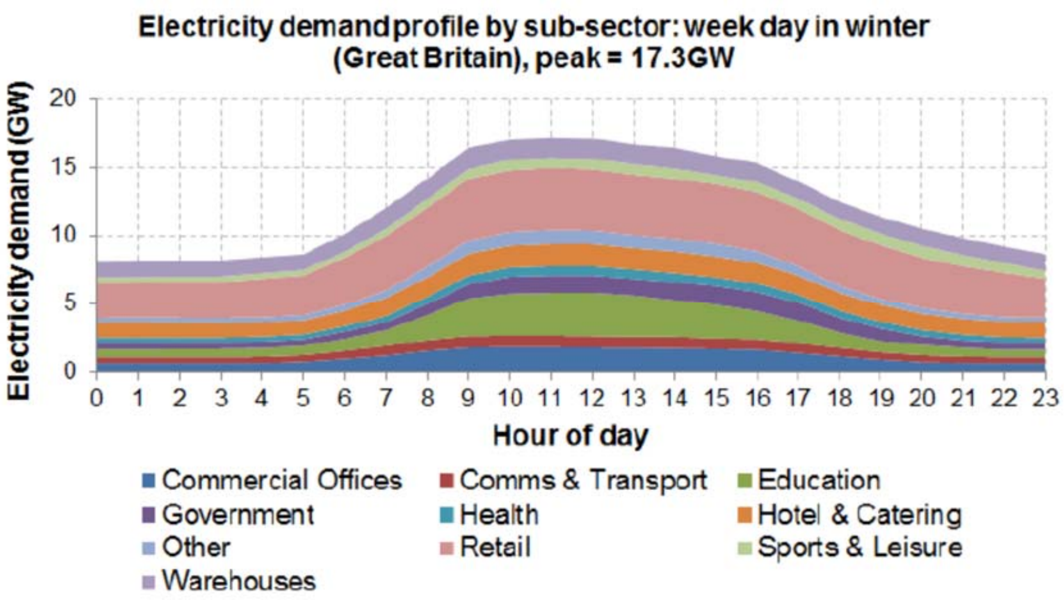


Figure 11 Electricity demand profile of non-domestic buildings by sub-sector for a winter week day [17]

3.3.1. A note on sector descriptions

The service sector as defined by DECC consists of Commercial, Public Administration, Agriculture and Miscellaneous [19] although the term is also used to mean Commercial and Public Administration only. Commercial and Public Administration are divided into sub-sectors as shown in Table 2.

The non-domestic subsectors (excluding industry) used by Element Energy [17] are the same as those defined under Commercial and Public Administration by DECC.

The Brattle model used data from various sources including: DUKES which uses the service sector defined by DECC; ECUK which uses a sector description made up of commercial offices, communication and transport, education, government, health, hotel and catering, other, retail, sport and leisure, warehouses; and Building Research Establishment (BRE) modelling data [15]

Commercial		Public Administration
Commercial Offices	Retail	Education
Comms & Transport	Sports & Leisure	Government
Hotel & Catering	Warehouses	Health
Other		

Table 2 DECC definitions of commercial and public administraion sectors

3.4. Primary substation demand

The previous section showed commercial demand profiles for Great Britain. This section looks at a data from a Primary substation and secondaries substations which it serves. The primary substation at Dickinson St in Manchester is chosen as an example and the data from this substation and its secondaries is used later in the analysis in Chapter 10. This primary serves city centre demand and consists of a high level of commercial demand such as banking, retail and restaurants with some residential demand. A graph of demand at this substation [20] on 24th November 2014 is shown in Figure 12. It can be seen that the demand shape is similar to the modelled commercial demands in Figure 10 and Figure 11. The base demand is around 5 MW rising up to around 11 MW, giving a plateau to baseload ratio of 220 % similar to that modelled in [15] and shown in Figure 11.

Figure 13 shows demands on some of the secondary substations which are on a feeder from the Dickinson St. primary substation. Data was not available for November 2014 so data was taken for the nearest Monday, the 25th November. The demands on these secondaries are mostly commercial with some residential demand. Here the diversity of demand shapes is apparent.

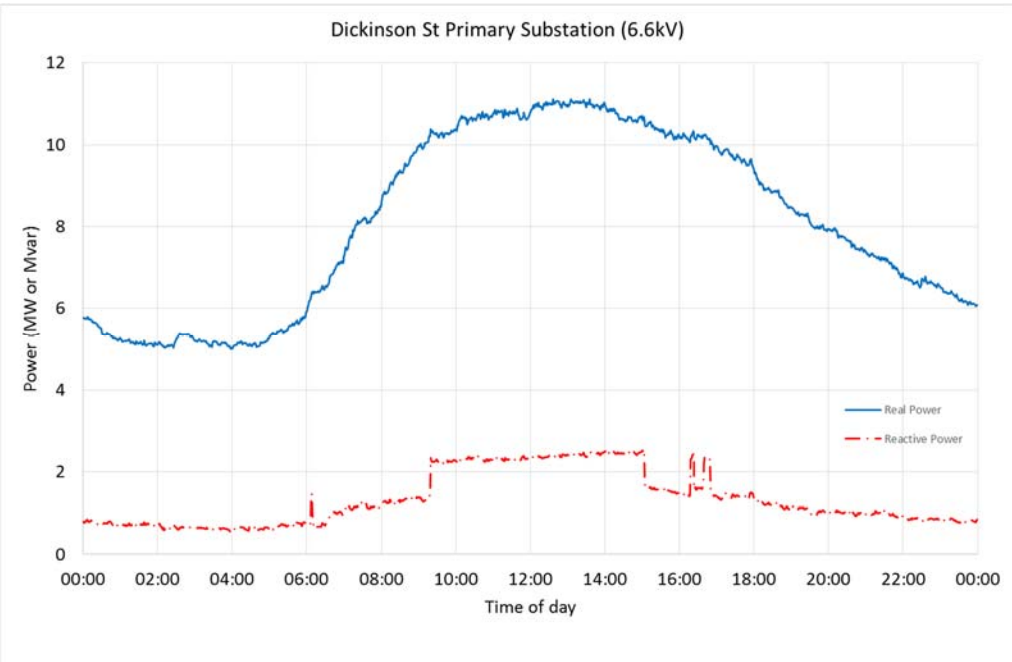


Figure 12 Dickinson Street 6.6kV sub-station demand, Monday 24th November 2014

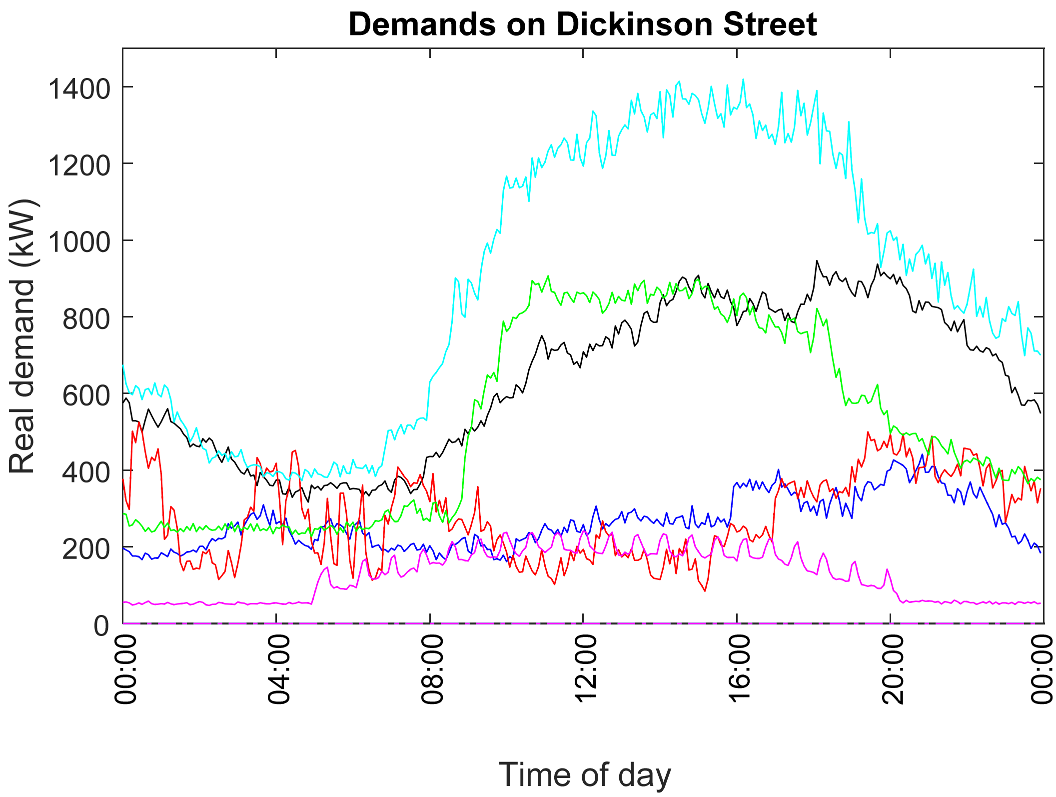


Figure 13 Demands on secondary substations feed from Dickinson St. Primary on Monday 25th November 2013

3.5. Demand smoothing

Individual customer demand aggregated over a larger part of the network is subject to 'demand smoothing'. This means that the actual aggregated demand for a group of customers can be significantly less than the sum of the maximum demand from each individual customer

Analysing hourly domestic demand data Paatero and Lund [21] note that the aggregated demand approaches the mean consumption curve for increasing numbers of customers. They calculate an error sum of the difference between the hourly demand for each household and the mean hourly demand for all households and summed over all hours:

$$\sum_{i}^{i=24} \left| \dot{E}_{\imath} - \overline{\dot{E}_{\imath}} \right|$$

where $\dot{E}_{\imath}$ is the hourly demand per household, $\overline{\dot{E}_{\imath}}$ is the mean hourly demand per household for all households and i is the index of the hour of day.

The logarithm of this error sum approximates a straight line decreasing with increasing numbers of households considered.

Similarly Strbac [22] writes about diversity in demand and states that the capacity of an electricity system supplying a large group of households would be about 10% of the total capacity required by each household if they were all producing their own electricity. He defines a 'coincidence factor' as the "ratio between maximum coincident total demand of a group of households and the sum of maximum demands of individual customers comprising the group". Put concisely this is the sum of all the demand maxima divided by the maximum of the summed (aggregated) demands:

$$\text{Coincidence Factor} = \frac{\max\limits_{\forall t}\left(\sum_{i=1}^{n} D_i(t)\right)}{\sum_{i=1}^{n} \max\limits_{\forall t}\big(D_i(t)\big)}$$

where $D_i(t)$ is the demand for user i at time t.

The coincidence factor has a theoretical maximum possible value of 1. Figure 14 presents a graph of coincidence factor with number of customers which show that when the number of customers is less than 1000, there is a reduction in coincidence factor with increasing number of customers. Beyond a 1000 customers the curve starts to saturate at about 0.1. The nature of this diversity can be used in planning the capacity of areas of the network. Strbac says that the coincidence factor *"represents the ratio of the capacity of a system required to supply a certain number of households and the total capacity of the supply system that would be required if each household were self sufficient"*

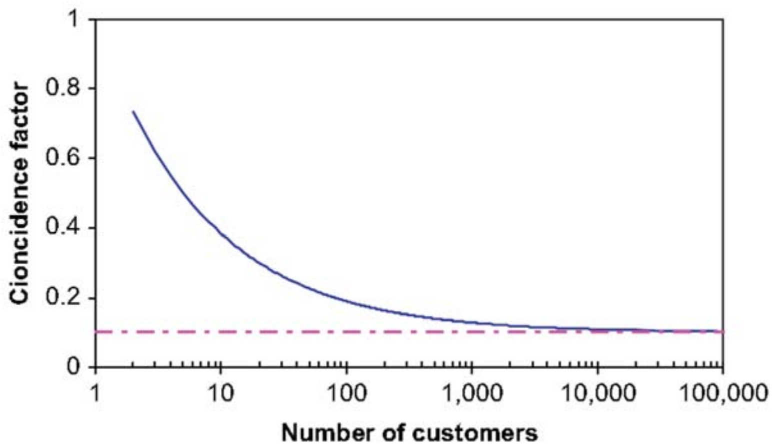


Figure 14 Load coincidence factor as a function of the number of typical households [22]

Widén and Wäckelgård [23] also use the “coincidence factor”, however Richardson, et al. [24] use a “diversity factor” which is the reciprocal of the “coincidence factor”. The “coincidence factor” has an advantage over the “diversity factor” in that it has a maximum possible value of 1 if the individual load maxima were all to occur simultaneously (note that the demand shapes could be different and still satisfy this condition). However, the “diversity factor” has no defined maximum value and would be very large if the maximum diversified demand is relatively small, which would be the case for high demand values with small peaks.

Whilst the theoretical maximum value for the coincidence factor is 1, the minimum theoretical value depends on the number of customers, n. If all the customers experience peak demand at a single time point but otherwise have zero demand and none of those peak demand times coincide, this gives a minimum coincidence factor which is $\frac{1}{n}$.

The term “after diversity maximum demand” (ADMD) is defined as the maximum observed demand per customer as the number of customers approaches infinity [25]. It is the limiting value of the coincidence factor and is indicated as a dashed line in Figure 14.

Diversity is an important concept for the work described later in Chapter 10 where synchronised peaks cause a reduction in distribution network capacity. Synchronicity is a lack of diversity.

3.6. Summary

This chapter has looked at commercial demand profiles and concepts of demand coincidence and diversity.

The UK commercial sector is dominated by lighting but heating, cooling and catering also contribute significantly. It was noted that different organisations describe the sub-sectors in different ways. The total demand plateau (i.e. a long duration peak) for the commercial sector is about 200 % of the baseload, which is a significantly larger ratio than for domestic demand. The demand at the primary substation at Dickinson Street in Manchester, UK, was seen to be comparable in shape with the total commercial demand. However, the secondary substation demands which are supplied from the

Dickinson Street primary show significant variation from one secondary substation demand to another. This diversity is an important concept in work described later in the thesis.

Chapter 4. DSR definition, benefits and applications

4.1. Definition of DSR

For the purposes of this thesis the term DSR will be used according to a definition by Ofgem [26]. They define DSR as:

"actions by customers to change the amount of electricity they take off the grid at particular times in response to a signal. As such, we refer specifically to 'transactable' demand-side response, where a customer chooses to change the way they consume energy. This could include choosing to change their behaviour and habits to alter their energy consumption, or choosing to let somebody else help them manage or control their energy consumption. These examples differ from ('non-transactable') system management activities that cause no discernable change in the quality of electricity supply and in which a customer has played no part. Transactable demand-side response differs from interruptions to customers' electricity supply that they have not chosen to incur."

This definition includes services where the "response" is not consciously made at the time of each request. For example a contract for STOR which uses automated demand switching can operate without the building manager's intervention because the decision or response to the signal was made at the time when the STOR provider tendered for a contract. Note that this definition includes demand reduction as well as demand increase (e.g. for high frequency response) since it relates to a change in the power or energy demanded from the network in response to a signal. DSR can also be effected with embedded generation, provided it meets technical requirements and is authorised for connection to the grid. Triad avoidance techniques are also covered by this definition since the reduction is in response to a signal of potentially increased charges.

The definition of DSR will not cover permanent changes in energy efficiency due to, for example, installing low energy lighting or insulating a building. These types of actions may be considered as a response to a signal (electricity price increases) but they are permanent and therefore do not add value in terms of flexibility.

It should be noted that when describing demand side interventions in the electricity system different authors may use different terms. Terms used include “Demand Side Response”, “Demand Side Management” (DSM) or “Demand Side Participation” (DSP). The “management” term in DSM might imply that the network operator is controlling the action, whereas the “participation” term in DSP might give the sense that the response is under the control of and decided by a demand side actor and it may be used to convey a sense of partnership. DSR may be regarded in the same way as DSP. However within the industry these three terms may be used interchangeably.

It should also be noted that different authors may use the same term to mean different things. For example Boshell and Veloza [27] state that DSM includes three aspects : energy efficiency, energy conservation and demand response actions. In their paper they describe energy efficiency as the installation of energy efficient technologies such as low energy lighting or thermostats. They use the term energy conservation to describe changes in end-user behaviour which reduce overall energy use, such as lowering the thermostat set point or delaying use of a washing machine until there are enough clothes to fill it. Demand response is described mainly in terms of customer action based on market and price signals, which result in load shifting. Other authors include these type of behavioural aspects under the term “energy efficiency”. For example Palensky and Dietrich [28] describe DSM under the following categories:

- Energy Efficiency
- ToU tariffs
- Demand Response
- Spinning Reserve

In their paper an “energy efficiency” measure results in immediate and permanent reductions in energy consumption (e.g. upgrading equipment to obtain better efficiency, insulating a building). They also include “energy conservation” as defined by Boshell and Veloza [27] (i.e. changes in user behaviour) under the term “energy efficiency”.

Energy efficiency and DSR, rather than DSM are terms used in the report by Element Energy [17]. They divide DSR into:

- Tariffs
- Contracts
- Automated devices

These relate to different levels of confidence in the response. Tariffs are used to encourage behaviour but do not define it. When considering contracts, it should be clearer, in general, what level and type of response to expect. For automated devices the confidence in the response, in general, should be even higher.

4.2. Network benefits and applications of DSR

This section will introduce applications of DSR.

4.2.1. Traditional electricity system perspective

Strbac divides the traditional electricity system into four main sectors [22]:

- Generation
- Bulk transmission
- Distribution
- Consumption (or demand)

The GB electricity system was designed as unidirectional with power flowing from centralised generation via the transmission network to the distribution network and on to the electricity consumer. Strbac's paper looks at the opportunities for changes in consumption that could make an impact on generation, transmission and distribution efficiencies and costs. He refers to these changes as Demand Side Management (DSM) however his use of the term DSM is consistent with the definition of DSR in this thesis.

4.2.2. Summary of DSR applications

Ceseña et al [29] report results from the ADDRESS project (Active Distribution network with full integration of Demand and distributed energy RESourceS). They consider DSR for capacity support from small commercial and residential electricity users for network capacity support under three business cases:

- avoidance of transmission level capacity charges for electricity retailers

- avoidance of capacity charges between interconnected DNOs for inter DNO power exchange, usually at the Extra High Voltage (EHV) level
- avoidance or deferment of system reinforcement costs for DNOs

Ma et al [30] describe generalised definitions of applications (or 'products') for load participation in ancillary services, energy and capacity markets. This is adapted and reproduced in part in Table 3.

Bradley et al [31] describe the benefits of DSR under eight categories. Some of the benefits overlap. Table 4 briefly describes each benefit and relates them to the four sectors of the electricity system as described by Strbac (in section 4.2.1).

Product Type	Description	Response Time (minutes)	Duration of Response (minutes)	Time to full response (minutes)	Frequency of Call
Regulation	Response to unscheduled net load	0.5	15	5	Anytime within bid period
Contingency	Rapid and immediate response to a loss of supply	1	≤ 30	≤ 10	≤ 1 per day
Flexibility	Additional load following reserve for large unforecast wind/solar ramps	5	60	20	Anytime within bid period
Energy	Shed or shift in energy consumption	5	≥60	10	1-2 times per day with 4 to 8 hour notification
Capacity	Alternative to generation	The highest 20 hours of system peak			

Table 3 Generalised product definitions for ancillary services, energy and capacity markets, adapted from [30]

Benefit according to Bradley [31]	Areas of the traditional electricity system [22] which benefit
a) Benefits from relative and absolute reductions in electricity demand This refers to long term benefits resulting from absolute electricity reductions which may be caused, for example, by a greater awareness of electricity use due to a real-time consumption display. This efficiency increase takes place at the demand side of the system. It is not relevant to the definition of DSR used in this thesis as this is energy efficiency.	Generation, Transmission, Distribution, Consumption
b) Benefits resulting from short run marginal cost savings from using DSR to shift demand Normally during peak demand it is necessary to dispatch the less efficient forms of generation which is a major driver of electricity price. Using DSR to shift demand can reduce the amount of energy dispatched with these less efficient generators.	Generation efficiency
c) Benefits in displacing new plant investment by using DSR to shift peak demand If the peak demand is regularly and reliably lower the generation required to meet the peak is reduced and longer term this means that there is reduced requirement for investing in new generation. This efficiency relates to generation that has the purpose of supplying energy (rather than balancing services). This benefit differs from the previous benefit in that it is concerned with the total amount of generation whereas the previous is concerning the efficiency of peak generation.	Generation investment (for energy)
d) Benefits of using DSR for emergency reserve DSR could be used to help manage emergency situations. This would be called relatively infrequently but would have the cost benefit of reduced investment in reserve generation.	Generation investment (for reserve services)
e) Benefits of using DSR to provide balancing for wind DSR could allow greater use of unpredictable wind generation. This is particularly relevant for areas/times of high wind and low demand. Since intermittent renewable generation is expected to increase the need for reserve will also increase in order to balance supply and demand. Using DSR to provide standing reserve has a value which depends	Transmission Balancing

on the flexibility of the generation system which would otherwise be used. However, according to Strbac, the value of DSR when compared to traditional providers of spinning reserve (e.g. OCGT plant) is less than £50 /kW which is “unlikely to be sufficient to fund implementation” [22].The benefits would be attributed to the transmission system, in terms of balancing supply and demand.	
f) Benefits of DSR to distributed power systems The electricity system was designed around centralised generation. Generation at the distribution network level can cause thermal constraints and voltage-out-of-limit problems. Increased penetration of distributed generation such as Combined Heat and Power (CHP) systems and renewable generation will increase the need for balancing, particularly because renewable generation output is driven by weather and the electrical output from CHP is driven by demand for heat [22]. DSR could allow greater penetration of distributed generation by giving more opportunity for balancing supply and demand at the distribution level. This benefit is similar to the previous in that it is to do with balancing but this benefit is attributed to the distribution system.	Distribution/Generation at Distribution level
g) Benefits in terms of reduced transmission network investment by reducing network congestion and avoiding transmission network reinforcement This benefit is attributed to the transmission part of the system. Strbac puts a value on transmission network reinforcement of £300 /MW km [22] but also notes that this value may increase due to difficulties in the planning process. He also states that if significant renewable generation were to be installed in the North of the UK it would increase the stress on the network due to the net North – South power flow. This would increase the value of DSR in the South of the country.	Transmission

h) Benefits from using DSR to improve distribution network investment efficiency This benefit is similar to the previous in that it refers to asset investment however this benefit is attributed to the distribution network. Strbac notes applications for DSR in deferring network investment; increasing amount of distributed generation that can be accommodated by the network; alleviating voltage constraints; relieving congestion at distribution substations; aiding outage management and reducing carbon emissions.	Distribution

Table 4 Benefits to the electricity system from DSR

4.3. DSR characteristics and demand recovery

4.3.1. DSR characteristics

Important parameters regarding DSR requirements, some of which were given in Table 3 are:

- response time
- duration
- depth of response in terms of power reduced
- expected frequency of calls
- reliability of response

The response time refers to the time for the response to obtain its maximum level. This may be governed for example by ramp-up times of generation or operating regimes of demand or generation which delay the onset of the response. Ma et al [31] note that for some cases demand can be curtailed more quickly than the ramp time of generation. See section 5.14.

The duration of response may be limited by loss of utility which refers to the fact that the purpose of the demand is being postponed. For example if the sub-load formed part of an HVAC system, utility would mean building occupant comfort, or for refrigeration in a chilled warehouse the utility would be the safe temperature limit.

The depth of response is limited by the proportion of demand which is considered flexible or curtailable compared to the proportion which is considered to be essential.

The expected frequency of calls may restrict the suitability of DSR since each call may incrementally reduce the utility of the demand to unacceptable levels. For generation the frequency of calls may not be problematic providing the fuel supply has sufficient volume, however the ramp time and minimum up-time may mean that generation is less suitable. If a generator is cycled on and off the maintenance costs and this would have to be factored into the costs of DSR in order to establish a minimum acceptable up-time. For Combined Heat and Power (CHP) systems the use of heat must be factored in. For example if a CHP system is operating purely to provide electricity with the heat being dumped to atmosphere it becomes a very inefficient form of generation. In terms of utility, the utility of the heat is wasted since it is not required.

For a single sub-load the reliability of response depends on whether the load is demanding power at the time of the call. For example if the sub-load has no demand at the time of the call there is no demand to curtail. The flexibility can never be greater than the demand. However, considering a number of aggregated loads the risk of zero availability is reduced and an availability factor may be used instead to give an equivalency to response from generation. This is the approach used in [32].

Depending on the type of demand which is reduced during a DSR call, that same demand may peak after the call in order to recover the energy which was not provided during the call. For example if the demand is space heating the space served will likely be at a slightly lower temperature at the end of the call. It would then take longer for the heating system to return to its normal operating state compared to if it had been managing that load without the DSR call. This recovery of energy will be referred to as demand recovery in this thesis, although some authors such as Motegi et al [33] refer to it as rebound.

Generation has been widely used to provide demand side services as is discussed in Chapter 5. Compared with demand reduction generation has a number of advantages:

- Providing the generation is grid connection enabled, the demand at the time of the call does not limit the response. If it were not grid connection enabled it would not be allowed to operate whilst the circuit is connected to the grid. For a demand reduction the response can never exceed the demand
- Depending on the type of generation the impact on utility is zero or very small. In the case of emergency standby generation the impact would only be in the case of a grid a supply failure to the building, then the generation would need to meet the emergency supply requirement. But the supply failure would negate any service available to grid in any case. The only ‘loss’ is that there would be less fuel to support extended emergency supply conditions.
- Generation is perceived as being more consistent than demand reduction in terms of the level and availability of response.
- Generation is likely to be able to provide a longer response time than demand reduction
- DSR by electricity generation is not subject to demand recovery.

However, by encouraging DSR participation through demand reduction as one of the routes to procurement of DSR, there is opportunity to increase not only the quantity of DSR resources (which may reduce procurement cost) but also their diversity in terms of location, response time and cost. In addition demand reduction offers some advantages over generation:

- Potentially faster ramp time compared to generation [30]
- Demand does not require special grid connection arrangements
- Demand reduction does not need to be ‘installed’ (although there may be metering and control required)
- There is no requirement for fuel and therefore no financial operational costs (though there may be an operational cost in terms of loss of utility)
- There is no additional CO2 burden either in terms of fuel/operation nor in terms of embedded carbon from manufacture and transport
- There are no polluting emissions such as NO_x, CO and particulate matter
- Existing building management systems (BMS) and smart metering could potentially form part of the signalling and verification system

4.3.2. Demand recovery after DSR by demand reduction

Cobelo et al [34] simulated the effect of disconnecting power to the chillers on an HVAC system for an hour. They also disconnected the HVAC chillers on an actual building in order to compare the simulation results with reality. The results from the actual building are reproduced from their paper in Figure 15 where they are compared against a baseline demand created from historical data. During the control action the demand reduces by around 200 kW compared to the baseline. However, when the chillers are reconnected there is demand peak which is 400 kW above the baseline which is around 700 kW. However the paper does not explain the reason the demand drops off dramatically from 14:00 hours

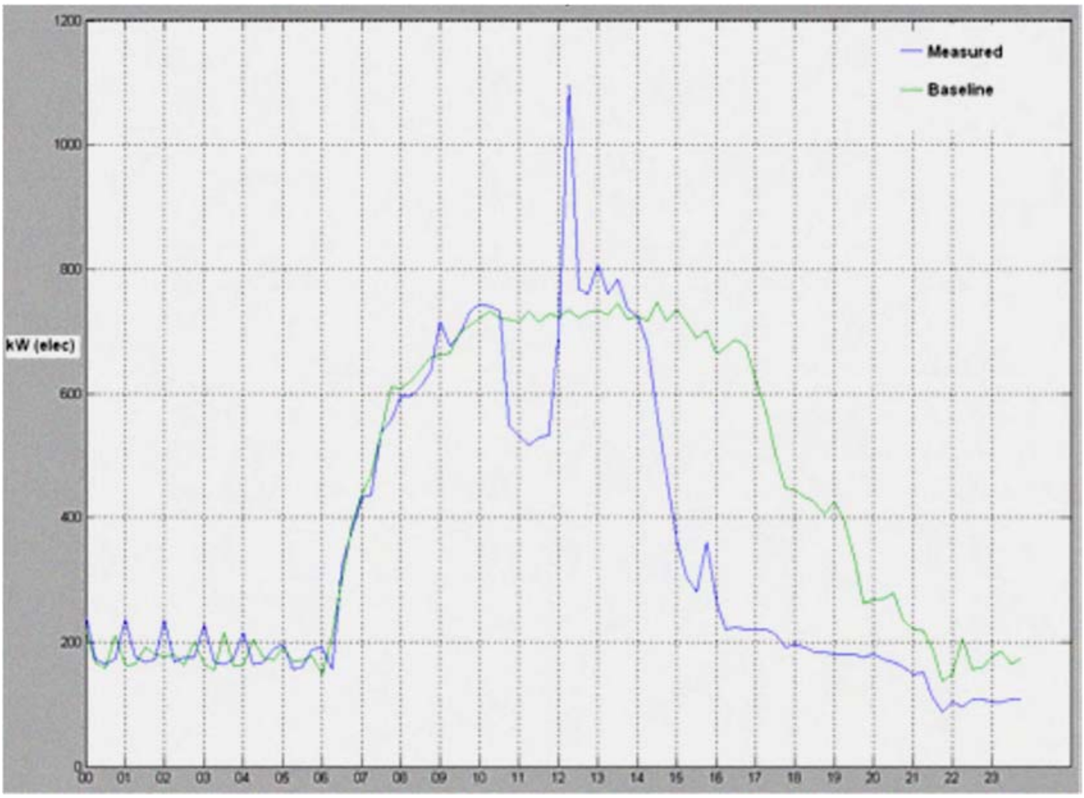


Figure 15 Whole building electrical consumption on the event day [34]

This sharp peak in demand after the demand reduction event is seen in demand reduction on systems which maintain a control bandwidth on systems with inherent storage, such as heating or cooling. The peak demand is due to the system returning to within its control bandwidth. The system is recovering energy that was not provided during the demand reduction.

Other authors have also noted this demand recovery response. Mathieu et al [35] examined the difference between the calculated demand baseline and the actual demand for demand response days for three electricity users. The users are: a bakery, a furniture shop and an office building. The demand response is due to critical peak pricing whereby the price is three times the normal rate between 12 – 3pm and 5 times the normal rate between 3 – 6pm. All facilities are based in the USA. They note that there is a demand recovery (which they refer to as rebound) on the demand for the furniture shop after demand response. They measure the recovery as the average of the difference between baseline and actual demand in the hour after the event. The demand shed and recovery values are shown in Table 5.

Date	Demand Shed 12 – 3pm (kW)	Demand Shed 3 – 6pm (kW)	Recovery (mean kW in hour after demand shed)
16th May 2008	73	67	50
8th July 2008	80	59	17
27th August 2008	124	83	-40
Mean	96	78	37

Table 5 Demand response parameters for a furniture store on three different days [35]

It should be noted that the demand reduction during the high pricing period was less than during the moderate pricing period. It is assumed this is due to the shop having less flexibility in demand possibly due to a reduced total demand. The results vary significantly across the three event days and for one of the days the demand recovery was negative, meaning that the demand immediately after the DSR event was less than the predicted baseline.

They also note that all of the facilities have reduced total energy demand on the demand response days, although they may have increased peak demands on those days.

It can be seen that both the demand shed kW and the demand recovery for the furniture store vary significantly on different days. This was also true for the bakery and to a lesser degree for the office building shown in Table 6 and Table 7 respectively.

Date	Demand Shed 12 – 3pm (kW)	Demand Shed 3 – 6pm (kW)	Recovery (mean kW in hour after demand shed)
16th May 2008	0	129	-7
8th July 2008	0	82	-4
27th August 2008	0	79	-68
Mean	0	102	4

Table 6 Demand response parameters for a bakery on three different days [35]

Date	Demand Shed 12 – 3pm (kW)	Demand Shed 3 – 6pm (kW)	Recovery (mean kW in hour after demand shed)
16th May 2008	44	74	2
8th July 2008	56	93	5
27th August 2008	51	103	-15
Mean	42	88	-1

Table 7 Demand response parameters for an office building on three different days [35]

Cobelo et al [34] state that the amount of demand shed is difficult to estimate since the building thermal simulations are complex and that parameters which are difficult to estimate (e.g. air infiltration through open windows, doors and gaps) is not only difficult to estimate but also have a large impact on the simulation result. For example a 50% increase in the estimated value of air infiltration would have a 20% impact on the value of the result.

In the Low Carbon London project for modelling loads with demand recovery, the recovery was assumed to be 150% of baseload in the first 30 minutes, then 110% of baseload in the next 30 minutes and same as baseload thereafter [36].

4.4. Summary

This chapter has defined the term DSR for the purpose of this thesis. It has outlined the applications of DSR and how the network can benefit from the use of DSR. The characteristics of DSR were discussed including a comparison of DSR by embedded generation with DSR by demand reduction. Demand recovery of demands with inherent storage was discussed. There has been little work on characterisation of actual demand recovery. The work that has been done indicates that not only is demand recovery difficult to predict it is also variable.

Chapter 5. DSR service types and value in the GB network and the potential of DSR in the commercial sector

5.1. Triads

Chapter 7 explores reduction of Triad charge using emergency standby generation and Chapter 8 explores the potential conflict of Triad and STOR services.

5.1.1. Description

In the GB electricity network the TNO gets paid for the use of its assets via Transmission Network Use of Service (TNUoS) charges. These charges are not 'initiated' by the TNO nor is any signal actioned by them, but form a part of the retail charges (bill) to the electricity user based on a measure of peak time usage. However since this may still influence the electricity users behaviour it can be considered as DSR under the definition used in this thesis. This only applies to HH metered customers since the TNUoS charges for non-HH metered customers are not explicit on the bill. For non-HH customers the TNUoS cost is calculated using an assumed demand profile in one of eight profile classes which are described in [16]. For HH metered customers the TNUoS charges are implemented by a system known as Triads. National Grid describes the Triads as *"the three half hour settlement periods of highest transmission system demand during November to February of a Financial Year, separated by 10 clear days."* [5] These three HH periods incur a significant additional charge and are not known in advance, but are calculated after the Triad season. Some suppliers give warnings about potential Triad periods but, as previously mentioned, KiWi Power believe that the Triad half hours are becoming less predictable perhaps because more electricity users are modifying their demand in response to Triad [37]. A case study by the author put the cost of Triad at £6,215 which amounted 5.1% of the total annual bill [38], which is described in Chapter 7.

It is thought that 1.2GW of demand is reduced by large (> 1MW) electricity users due to Triad from 16 GW total demand [11], which is around 7%.

5.1.2. Value in reducing Triad demand

In terms of the benefits in Table 4, Triads directly benefit *(g) "...reduced transmission network investment by reducing network congestion and avoiding transmission network* *reinforcement*." It will also impact on *(b) "Benefits resulting from short run marginal cost savings from using DSR to shift demand"* and *(c) "Benefits in displacing new plant investment by using DSR to shift peak demand"* although these are concerned with generation and this is not the purpose of Triad.

The Triad charge varies depending on the region and in general the cost increases for regions further South. Triad costs are significant in order to discourage demand at peak times. For example, for the North West region the Triad charge for Winter 2016/17 is 42.828 £/kW which is based on the average demand over the 3 Triad half-hour periods. The minimum charge was 40.24 £/kW in Southern Scotland whilst the maximum charge was 51.87 £/kW in London [39]. The aggregator KiWi Power believes that Triads are becoming more difficult to predict [37].

Since Triads periods are billed at a significantly higher rate than non-Triad half-hours, Electricity users can reduce their bill by reducing demand when they think there may be a Triad period. Triad warnings may be provided by their retailer or another company and some companies will reduce their consumption during these warnings. It is expected that the Triad charges will rise by 90% from 2015/16 to 2020/21 [11]

5.2. DSR balancing service types

There are a range of services for balancing distinguished by there response time and the direction of balance required (demand greater than supply or supply greater than demand).

In terms of the benefits as described in Table 4, balancing services are designed to bring *(d) "Benefits of using DSR for emergency reserve"* and *(e) "Benefits of using DSR to provide balancing for wind"*.

Typically when there is a mismatch between supply and demand the initial response comes via the automated frequency response service which operates over time-scales of seconds up to half an hour. Balancing is provided over longer time scales by bringing 'reserve' services online. This is shown in Figure 16.

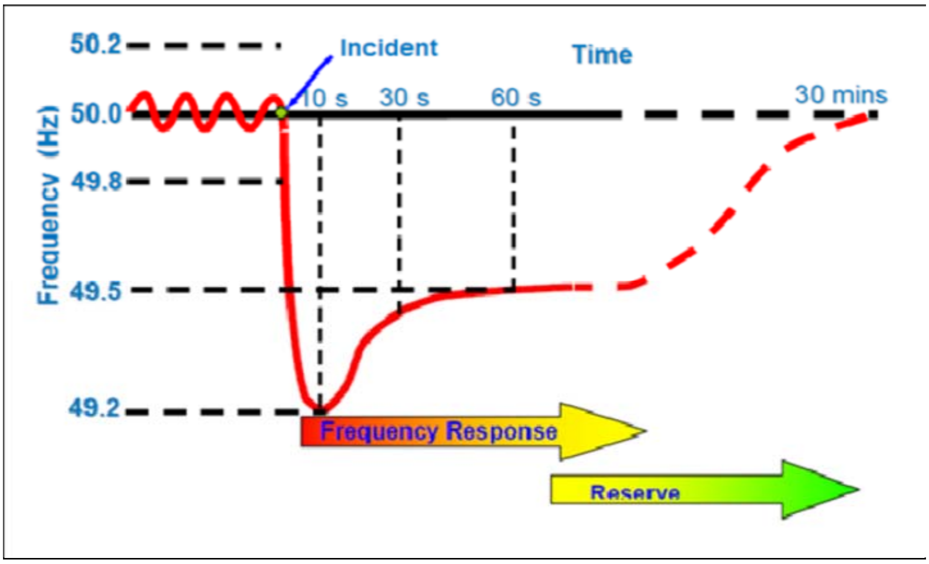


Figure 16 Frequency Response and STOR timescales [40]

5.3. STOR

STOR is a reserve service procured by the SO in order to manage system imbalances. A model of STOR calls is developed as part of the software suite which is described in Chapter 6, Chapter 8 and Appendix B: The modelling software suite. This model is used in Chapter 6 to explore potential conflict between STOR and Triad service on the net income of the STOR provider.

5.3.1. Description of service

The STOR service is designed to bring additional generation or demand reduction on-line within a timescale up to 4 hours. However, National Grid prefers services which can come online at much shorter notice. For example in the year 2013/14 only 2.6% of the units proving STOR had a response time greater than 20 minutes and the majority (65.8%) had a response time less than 10 minutes.

STOR providers must be able to provide at least 3 MW of generation or demand reduction (which can be from more than 1 site) at least 3 times a week for at least 2 hours [2]. National Grid will call for the contracted MW "no more, no less" [3]. The recovery period between calls can be up to 1200 minutes [4].

National Grid defines STOR availability windows which vary in time and by season but are typically around 7am – 1pm and 4pm – 9pm. According to Element Energy 3GW of STOR (demand reduction) could be provided by the non-commercial sector through shifting loads for hot water, lighting, HVAC and freezer loads. In addition, STOR could be provided through back-up generation. There is more than 3GW of generation from commercial companies (whose main business is not generation) but the capacity of back-up generation is estimated to be much higher at about 20GW – 30GW. This is not necessarily a reliable source of power since it may be rarely used. However, in a 'more-flexible' future, grid aggregators could help to exploit this potential [17].

STOR is open to Balancing Mechanism (BM) and non-BM providers (see section 2.3.3). Providers submit their availability over window periods which are defined for 6 seasons over the year for "working days" and "non-working days". Non-working days refers to Sundays and Bank Holidays. Working days refers to Monday to Saturday [5]. The seasons are of varying length and there can be up to three windows (although there are usually two) per season [6].

STOR is procured through tender rounds of which there are usually 3 per year. Providers can tender for seasons up to 2 years ahead [6]. Dispatch is based mainly on cost but other factors may be taken into account such as response time, location and size of units [3]. For example in terms of location in tender round 24 (market day 22nd August 2014) there were no STOR units based solely in Scotland, although it is possible that there may have been some Scottish units which came under the category "multiple locations" as shown in Table 8.

Location	Total Units Tendered	Total Units Accepted	Total MW Tendered	**Total MW Accepted**
Scotland	16	0	398	**0**
North	114	42	3354	**922**
South	281	67	8471	**2109**
Multiple	278	149	2036	**1024**

Table 8 locational distribution of STOR for whole season calculated from [41]

5.3.2. Participation requirements

The delivered energy will be measured on a minute basis compared to the baseline. The baseline is "what the unit was doing when the STOR service was instructed" [8]. Non-BM providers must have metering installed at their own expense [9]. Signals to start and stop the service, if not automated, must be implemented within 5 minutes [9].

A STOR site can have mixed generation and demand provided that it consists of individual generation sub-sites and individual demand sub-sites. In addition two meters must be provided to monitor availability and actual STOR response [42].

5.3.3. Types of service

There are 3 types of service:

a) Committed Service
b) Flexible Service
c) Premium Flexible Service

The committed service provider must be available for all windows and can only be unavailable (without penalty) for reasons of breakdown or planned maintenance.

The flexible service is only available to non-BM providers. They only need to define their availability at the week ahead stage (by 10:00 on the Friday of the preceding week) – this applies to flexible and premium flexible service. They have greater freedom to choose how long they can provide the service. National Grid may reject a flexible service provider and would not then have to make an availability payment if they did so by 16:00 on the Friday of the preceding week.

The premium flexible service was introduced in tender round 22 (2014) [43]. Premium windows are of greater value to National Grid and they are defined for the whole 2 year period. The product was changed in TR25 so that from year 10 premium windows are only Monday to Friday [10]. NG commits to accepting 85% of availability of premium windows.

The different types of service, provider types and availability windows are summarised in Table 9. The premium windows for the year 2015/16 are given in Table 10.

	BM	Non-BM	Availability Windows	Notes
Committed Service	Yes	Yes	All	Can only be unavailable due to breakdown or planned maintenance
Premium Flexible Service	No	Yes	Premium	Premium windows are identified for each season for the whole 2 year contract
Flexible Service	No	Yes	Flexible - chosen by provider	Providers must declare their availability a week ahead and at this stage become committed

Table 9 Types of STOR service

Premium Windows for Year 9 (2015/16)		
Season 1	1st Apr 2015 to 27th Apr 2015	Window 1
Season 2	27th Apr 2015 to 24th Aug 2015	Window 1
Season 3	24th Aug 2015 to 21st Sep 2015	Window 2
Season 4	21st Sep 2015 to 26th Oct 2015	Window 2
Season 5	26th Oct 2015 to 1st Feb 2016	Window 2
Season 6	1st Feb 2016 to 1st Apr 2016	Window 2

Table 10 Premium Windows for Year 9 [44]

5.3.4. Exclusivity

The STOR service is exclusive meaning that providers may not participate in other services (from third parties or National Grid) that would interfere with their ability to provide STOR. Out-with the contracted windows a provider is at liberty to provide other services providing that this does not affect their ability to provide STOR [3]. The Flexible Approaches for Low Carbon Optimised Networks (FALCON) project noted that this exclusivity is because National Grid pays a premium for STOR capacity (in the availability payment). It also noted that it would be possible for a provider to make itself available for a frequency service where STOR availability was not committed [11, pp. 21]. The report recognises that “National Grid is a key actor to engage in dialogue around demand response in order to avoid conflict with the STOR programme and the Triad scheme [11, pp. 88]. The potential for increased or decreased value to a STOR provider is explored in Chapter 8. National Grid states that STOR is an exclusive service: “For system security purposes, when providing a STOR service, you are excluding all other services, which would interfere with your ability to provide your contracted MWs under the STOR Contract – please note this applies in respect of other National Grid services, as well as services with an independent third party.” [3]

5.3.5. Value to the service provider

There are 2 main types of payment for STOR and these are set by the provider in the tender. These are an availability payment in £/MW for each hour of availability and a utilisation payment in £/MWh for energy supplied according to despatch from National Grid. The availability payment is paid regardless of utilisation except that in the case of the flexible service if National Grid rejects the availability. For BM providers the utility payment is effected through the Balancing Mechanism.

If a unit fails to provide STOR the availability price will be reduced by 1% for each availability window containing a failure up to a maximum of 30% [42].

Non-BM providers can also offer availability outside of the availability windows which are defined as “optional windows”. The provider must indicate their availability and if utilised will receive payment at the “optional energy utilisation price (specified in their tender) [4]. However no availability payment will be made [3].

For the STOR year 2013/14 the average prices were as follows:

- Availability payments 5.83 (£/MW)/h
- Utilisation payments 191.20 £/MWh

Taking long term contracts out these payments reduce to 4.94 (£/MW)/h and 183.76 £/MWh a reduction of 28% and 7% respectively [6]. For the 2014/15 STOR the availability and utilization prices excluding long term contracts was 2.56 (£/MW)/h and 157.69 £/MWh. This indicates that the financial benefit to the service to providers is decreasing. However, whilst the prices for STOR are reducing, the volumes and overall cost are increasing [11, pp. 109]

5.4. STOR runway service [45]

The STOR Runway service allows a contract for a STOR response development to be built up within an agreed timeframe. It allows a STOR contract to be secured for providers who are currently unable to give the full (3MW or greater) response. As with STOR tenders can be *committed*, *flexible* or *premium flexible*.

5.5. Enhanced optional STOR [45]

This is essentially for existing providers of STOR (they must have approved metering in place) to offer additional demand response from additional units which are not currently used for STOR.

National Grid has a requirement for provision of a volume of an Enhanced Optional STOR Service from non-BM Providers on a trial basis for the Winter of 2016. This service creates an opportunity for National Grid to access additional non-BM volume closer to the real time. The deadline for tender submission was 8th January 2016 12:00pm. It is unclear if this service will continue.

5.5.1. Service assessment

In order to provide the service, the provider must meet the pre-qualification criteria. This includes the minimum technical parameters for non-BM STOR and enhanced response time <= 20 mins. Units will then be assessed on a combination of response time, utilisation price, location and historical performance of assets in other balancing services.

5.6. Demand turn up

5.6.1. Description

Demand turn up [45] is a service to encourage large energy users and embedded generators to either increase demand (through demand shifting) or reduce generation when there is excess energy on the system which is typically overnight and weekend afternoons. This is an economic solution to managing excess renewable generation when demand for electricity is low. The service ran from May to September 2016, with further opportunities expected in 2017.

5.6.2. Participation requirements

As Demand Turn Up is new service for 2016, there is an element of flexibility around parameters such as speed of response to an instruction and duration of response, in order to make the service more accessible. For 2016, a Demand Turn Up provider must deliver a minimum of 1 MW, which may be achieved by aggregating a number of smaller sub-sites (of at least 0.1MW each) within the same Grid Supply Point (GSP).

5.6.3. Value to the service provider

There are two service windows:

Overnight window: every day 23:30-08:30 (May and September) and 23:30 – 09:00 (June – August)

Day service window: weekends and bank holidays 13:00-16:00

Payments for demand turn up are given in [46]. For 2016, the providers could choose the utilisation payment as £60/MWh, £75/MWh or above £75/MWh (where utilisation payments are above £75/MWh there is no availability payment). The Availability Payment was fixed at £1.50/MW/h.

From 2017 provider will set the availability and utilisation payments in their tender.

5.7. Firm Frequency Response FFR

5.7.1. Description of service

FFR is a short term balancing service. It is divided into static and dynamic response services for low frequency and high frequency events.

5.7.2. Static and dynamic service

Frequency response can be dynamic or static. In dynamic response the level of response is proportional to the frequency deviation. For static response the provider gives its full response once the trigger level frequency has been reached. National Grid prefers dynamic response. For the Static Service National Grid do not stipulate a minimum run time. There are maximum run times depending on the system frequency. For example, they require that a generator will auto stop once the frequency has recovered.

5.7.3. Participation requirements for low frequency events:

To help manage low frequency response there are two types of response known as primary and secondary response:

- Primary response is an increase in active power from a response provider within 10 seconds which must be maintained for a further 20 seconds.
- Secondary response is an increase in active power from a response provider within 30 seconds which must be maintained for a further 30 minutes.

The requirement for secondary response is larger than requirement for primary response.

5.7.4. Participation requirements for high frequency events

For high frequency response the service provider must increase its active power demand within 10 seconds and this must be sustained indefinitely.

5.7.5. Technical requirements

The technical requirements are detailed below:

- Have suitable operational metering
- Pass the FFR Pre-Qualification Assessment
- Deliver minimum 10MW Response Energy
- Operate at their tendered level of demand/generation when instructed (in order to achieve the tendered Frequency Response capability)
- Have the capability to operate (when instructed) in a Frequency Sensitive Mode for dynamic response or change their MW level via automatic relay for non-dynamic response
- Communicate via an Automatic Logging Device
- Be able to instruct and receive via a single point of contact and control where a single FFR unit comprises of two or more sites located at the same premises.

From 1st April 2017 the minimum response power will reduce from 10MW to 1MW [47]

5.7.6. Value to the service provider

Table 11 reproduced from [48] gives the prices for successful FFR tenders between January 2013 and January 2016.

Service Types	Price in (£/MW)/h
Primary, Secondary and High	25 - 45
Primary and Secondary	15 - 22
Secondary (mostly static service providers)	2 - 5

Table 11 FFR prices for successful tenders January 2013 – January 2016 [48]

5.8. Frequency Control by Demand Management FCDM

5.8.1. Description of service

This service interrupts a customer's demand for up to 30 minutes when the system frequency falls below a threshold as shown in Figure 17. The interruptions are likely to occur between about ten to thirty times per year.

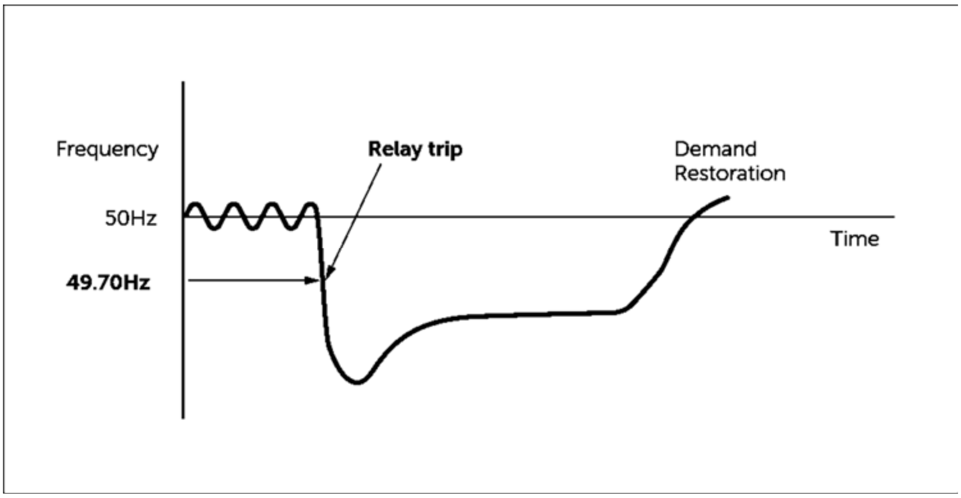


Figure 17 FCDM taken from [49]

5.8.2. Participation requirements

The service must be provided within 2 seconds of the trigger and deliver for at least 30 minutes. The minimum response is 3MW which may be aggregated at the same site. Operational metering is required and a signal must be output to National Grid monitoring equipment.

The provider is required to declare availability for each Settlement Period on a weekly basis. National Grid can accept or reject the availability. If it is accepted National Grid will give availability payment (£/MW/h) on the metered demand over the period agreed.

5.8.3. Value to the service provider

There is no available market information

5.9. Enhanced Frequency Response (EFR)

5.9.1. Description of service

The Enhanced Frequency Response (EFR) service was designed for battery storage and as such a provider offers response to positive and negative system frequency deviations. There is a dead-band of system frequency in order to provide time for the battery to return to an optimal state of charge. However, it is open to any provider, not just battery system owners, that can meet the requirements.

National Grid has procured 200MW of EFR through the tendering exercise held in July 2016.

5.9.2. Participation requirements

100% active power within 1 second or less. (This is in contrast with existing frequency response services of Primary and High which have timescales of 10 seconds, and Secondary which has timescales of 30 seconds [50].

5.9.3. Value to the service provider

In 2016 8 tenders were accepted to provide 201 MW of EFR [51] as shown in Table 12. The tenders are mostly for 4 years (35088 hours). It is not known if National Grid will be procuring more EFR in the future or not. The prices ranged from 7.00 to 11.97 £/MW for each hour [51].

Provider Name	Provider Type	Enhanced Response (MW)	GWh of EFR (1 d.p.)	Average tender price in £/MW of EFR/h	Tender excludes typical Triad hours?
EDF Energy Renewables	Storage	49	1719.3	7.00	FALSE
Vattenfall	Storage	22	771.9	7.45	FALSE
Low Carbon	Storage	10	337.6	7.94	TRUE
Low Carbon	Storage	40	1350. 6	9.38	TRUE
E.ON UK	Storage	10	350.9	11.09	FALSE
Element Power	Storage	25	877.2	11.49	FALSE
RES	Storage	35	1228.1	11.93	FALSE
Belectric	Storage	10	350.9	11.97	FALSE

Table 12 EFR accepted tenders reproduced from [50]

5.10. Summary of balancing services provided by DSR

Table 13 reproduced from a PA Consulting report [11] shows the balancing services that can be provided by DSR. The same report stated that there are no official values of current total volumes of DSR. Although there is data available, it is dispersed [11]. However they provide a table of the values of SO contracted DSR by service. This is reproduced in Table 14

Scheme	Total Capacity (MW)	Estimated DSR Capacity	Notification Time	Minimum Capacity (MW)	Procurement Method
STOR	3,444	237	20 minutes to 4 hours	3	Tendering
FFR	600	25	30 seconds	10	Tendering
FCDM	No data	No data	2 seconds	3	Bilateral contracts
Demand Side Balancing Reserve (DBSR)	313	133	2 hours	1	Tendering
Fast Reserve	180	No data	2 minutes	50	Tendering

Table 13 Balancing services that can be provided by DSR [11]

Service	Contracted in 2015/16 (MW)
Triad avoidance	1,200
Committed STOR	27
Flexible STOR	210
DSBR	133
Firm Frequency Response	25
Total (inc. flexible STOR and DBSR)	1,595
Total (exc. flexible STOR and DBSR)	1,252

Table 14 Contracted DSR by service in 2015/16 [11]

5.11. DNO DSR service requirement

The use of DSR services by DNOs has been demonstrated in some LCNF projects such as C2C [52], FALCON [53], Customer Led Network Revolution (CLNR) [54] and Customer Load Active System Services (CLASS) [55]. However, DSR has not yet been widely used in a Business as Usual (BaU) sense. DNOs are starting to implement DSR in services such as those developed in CLASS but in general this type of activity comes under “next steps” in a recent report by the Department for Business, Energy & Industrial Strategy and Ofgem [56]. A DNO may wish to procure DSR for thermal or voltage constraint management or for managing security of supply. These may enable the deferral of network expansion. Sustainability First state that these avoided cost values are “likely to vary significantly with voltage, location and loading” [57] and suggest a figure of £40 - £60 /kW p.a. Some authors have quantified these values in more detail [29, 58]. Network expansion deferral may also offer some indirect commercial benefits such as flexibility in terms of the timing of network expansion. This would allow the DNO to make a more optimal decision at a later date based on up-to-date operational experience. In addition, DSR may be seen as a scalable investment that can be augmented as and when required, whereas network expansion is a much larger one-off capital investment. In addition DSR investment can be scaled back if necessary at a later date.

5.11.1. Distribution network capacity and security of supply

Strbac describes distribution networks as passive systems in which the real-time control problems have been resolved in the planning stage [22] and that network capacity utilisation at peak load is usually less than 50%. Other authors have also noted that the GB planning requirement, P2/6, means that essentially half the network capacity is unused [59]. Strbac also notes that the average use of generation capacity is less than 55%. By using DSR, network utilisation could be increased by having the option to curtail demand in the event of generator or network outage, so as to avoid overloads which would otherwise occur. In this way network security would be maintained while increasing the utilisation. Network capacity may be reduced due to synchronised DSR calls by demand reduction where demands exhibit energy recovery. This is explained in Chapter 10.

5.12. The potential of DSR in the commercial sector

Industrial electricity users have engaged with DSR to a significant degree, however it is less common for commercial or residential users to participate. The work in this thesis considers commercial DSR since it represents an untapped resource and commercial demand represents a large proportion of the evening peak demand. In addition there is existing infrastructure and systems such as emergency or critical back up generation and building management systems that already provide generation and demand control services at the building or estate level (sometimes referred to as "behind the meter"). These could be engaged for DSR purposes. Chapter 7 quantifies the benefits of using emergency standby generation to reduce the transmission network use of service charge.

5.12.1. Aggregated Commercial Demand Profile

The demand on commercial buildings in the UK is relatively flat from around 8.30 am to 4.00 pm with the peak at about 11.00 am (see Figure 10). Element Energy estimate that commercial demand contributes 15GW (30%) to the GB total evening peak demand on a typical winter weekday. More than half of this is from retail, education and commercial offices which contribute around 25%, 18% and 11% respectively [17]. However they recommend DSR engagement with all sub-sectors since these contribute 5 -10% each to the evening peak Element Energy [17].

In the UK commercial sector electricity demand is dominated by lighting, but heating, cooling and catering also contribute significantly [18].

5.12.2. Commercial sectors suited to DSR

KiWi Power is an aggregator that include in their list of clients: Colchester Hospital, Marriott Hotels, Sembcorp Bournemouth Water (utility), Time Inc. (publisher) Trinity Mirror Group, and a financial institution.

5.12.3. Sub-load types suited to DSR

Element Energy [17] suggest that the most suitable loads for time shifting are thermal and lighting loads such as: space cooling & ventilation; heating; hot water; refrigeration and lighting. Other load types with limited opportunity for load shifting are catering and computing. Space cooling and ventilation can be interrupted for up to 30 minutes without any significant impact on the environment and one organisation states that they routinely switch off HVAC systems for up to an hour at times of non-extreme ambient temperatures.

The potential for DSR depends on whether there is any scope for reducing lighting load. The report from Element Energy [17] includes figures with and without reduced lighting load based on DSR experiences in California. The estimates of DSR potential are 1.2-4.4GW (8 – 30% of peak demand) with lighting flexibility or 0.6 - 1.8GW (4 – 12% of peak demand) without lighting flexibility [17]. Few of the consultees they interviewed suggested lighting reduction as a form of DSR although some of them are reducing their energy consumption by installing low energy lighting. The load for lighting is 39% (~40TWh/year) of the total demand within the commercial sector but Sustainability First are also of the opinion that this is unlikely to be a candidate for load shifting but that greater efficiency measures are more likely [15].

5.13. STOR in the context of the commercial sector

Grünewald and Torriti [9] made a comparison of standby generation and load shifting as demand response measures in the UK non-domestic sector. They only considered facilities with generation which did not have an export licence. This means that the maximum response from generation is limited by the maximum demand. From 500 sites they conducted a detailed analysis of 176 sites in the sectors:

- Warehouses
- Communication
- Hotels
- Offices

Only a small majority of these were engaged in load shifting. From the analysis they concluded that policy favoured standby generation over load shifting. Part of the reason for this is that DSR calls are often at short notice. They note that whilst STOR providers can theoretically have up to 4 hours to respond in practice it is called on much shorter timescales. Based on data from the STOR tender round 17 (2012) they infer that more than 85% of contracted STOR had response times of between 5 and 10 minutes. Data for the period 2014/15 shows this has decreased with about 55% of STOR having a response up to 10 minutes [10]. However almost 99% of STOR has a response time of 20 minutes or less, see Figure 18. The main perceived challenge for aggregators is the response time. However a qualitative investigation indicated that allowing a response time of 20 minutes may double the DSR available via load reduction compared to a 2 minute response [9]. However, the paper makes no assessment of the possible DSR available for response times of between 5 and 10 minutes. Grünewald and Torriti [9] noted that within the Industrial & Commercial (I&C) sector communications was well placed to offer DSR. This is because it has substantial standby generation on mobile telephone stations in order to meet a high availability requirement of 99.999%.

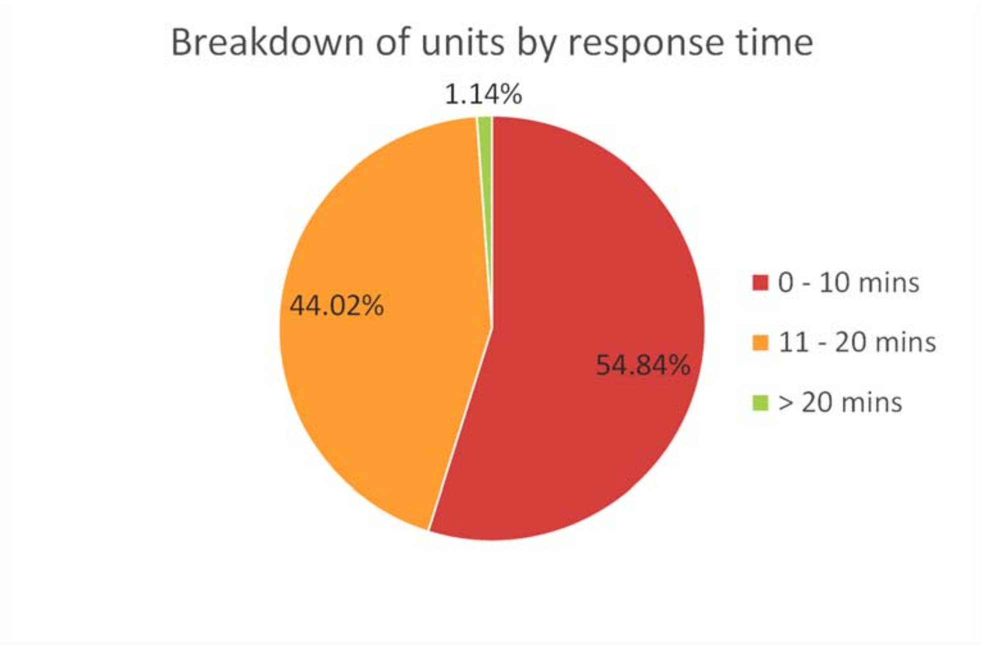


Figure 18 Breakdown of STOR units by response time [60]

The conclusion that policy favours standby generation over load-shifting DSR is also supported by SmartGrid GB and Bird & Bird LLP [61] who highlight that different forms of DSR can respond at different speeds. They also stated that “a ‘one size-fits-all approach’ may exclude certain DSR potential that could usefully contribute or equally, fail to make the best use of DSR potential that could respond in a quicker time frame.”

5.14. Frequency response in the context of the commercial sector

Ma et al [30] describe a methodology for modelling demand response resources for providing ancillary grid services. They note that for some cases demand curtailment is better than thermal or hydrogeneration since demand can be curtailed more quickly than the ramp time of generation. Drawing out the differences in requirements for ancillary service provision compared to energy services they note that for ancillary services:

- speed and accuracy are more important
- the energy requirement is less
- the requirement exists across the whole year, not just at peak times

Element Energy state that non-domestic buildings can provide a large part of requirement for the frequency response through DSR and the most suitable sub loads are refrigeration and HVAC systems and possibly lighting [17].

5.15. ToU tariffs in the context of the commercial sector

Element Energy estimate that ToU tariffs may provide between 1.1 and 4.0GW of flexible load during the peak hour (5 – 6pm).The amount of flexibility in the commercial sector tails off toward 6pm because the lighting load reduces as a proportion of the total load around 6pm [17].

5.16. Factors affecting DSR participation

DSR in the UK to date has been mainly in energy intensive sectors such as heavy industry and many studies have found little DSR uptake in the commercial sector [17]. Torriti, et al. [62] also state that some of the DR programmes in the EU have focussed on large industry instead of taking a wider approach to include commercial and domestic customers.

5.16.1. Factors that encourage engagement with DSR calls

Whilst the amount of financial benefit influences customer engagement with DSR it is not the only criteria. Other factors such as flexibility, willingness to reduce the comfort, also come into play [63].

Faruqui and Palmer [64] analysed several dynamic pricing tariff experiments and concluded that the level of Demand Response was related to the ratio of peak to off-peak prices. They used data from 74 tests taken from 9 pilot trials mostly in the USA between the years 2003 and 2010. The trials were selected from 126 based on their statistical quality (e.g. if the participants were selected at random). They used a model relating the peak reduction percent to the logarithm of peak to off peak price ratio which explained about half of the data. This suggests that the peak reduction increases with peak to off peak price ratio but with gains falling off at higher peak to off peak price ratios. They do not state what type of customers are involved in the trials but since they compare the effect of enabling technologies such as *"in-home displays, energy orbs and programmable and communicating thermostats"* it is thought that at least a significant proportion of customers are domestic.

5.16.2. Barriers to uptake of DSR

Interest in direct load control in the UK has been limited due to a lack of offers from suppliers, unclear financial incentives, an unwillingness to have supply interrupted and concerns over new equipment installation and maintenance [17].

5.16.2.1. Energy users

There has been little interest in DSR from the Commercial sector and Element Energy [17] conducted a small survey of companies in order to gain some understanding of the reasons for this. Only 16 interviews were undertaken and whilst their report admits that this is not a significant number they suggest that it does give general indication as to what some of the barriers might be. They concluded that common themes (amongst a wide range of barriers) were:

- Energy is not a focus of most for the companies. Some companies are taking energy efficiency measures such as low energy lighting but for the majority DSR is not a priority.
- Companies are concerned that DSR would lead to a reduced level of service of comfort in the building
- Companies were either uncertain about the financial incentives or thought they were low

Ofgem [26] grouped issues in DSR engagement identified by stakeholders in three categories:

- Confidence in the value of DSR in order to justify investment.
- Effective signalling of DSR service value
- Awareness of opportunities

They noted that distribution charging is a poor signal for smaller customers. Referring to the complexity of tariffs they stated a need to balance simplicity of tariffs against being able to offer new and more sophisticated tariffs with smart meters. Lack of understanding of the energy market was also an issue.

A report for Low Carbon London [65] also mentions the perception that the costs of DSR are higher than the value of the reward but it also expresses the opinion that aggregators are beginning to change these perceptions with energy audits. They also cite split-incentives as a barrier whereby an energy manager may have different priorities than those of a compliance officer and that there may not be time given to fully explore the benefits. In London most commercial property is rented and whilst landlords may be keen to save money through DSR, they will not directly experience any consequences of this.

A CLNR report on trials [66] notes that most I&C DSR is provided by standby generation rather than demand turn down. A different report from the CLNR project says that this may be due to negative perceptions about the impact of DSR on operations and level of service which are high priority in the I&C sector [67].

For DNO DSR it was noted that some TNO procured DSR contains exclusivity clauses [67]. An example of this is the STOR service [42]. This is a barrier both to procurement of DSR and engagement with DSR. For example if DSR can be delivered into different mechanisms, the DSR provider has a better business case for engaging with DSR. Although this may not represent the best value for money for the procurers.

5.16.2.2. Aggregators

Aggregators may not participate in the Balancing Mechanism due to the current rules of the BSC in which parties which are not directly responsible for the BM exports or imports are excluded [11].

A barrier to aggregators providing balancing services such as STOR and Frequency Response is that there is a high number of different services with varied structure and information on these may be diverse and unclear [11].

5.16.2.3. Procurers

The Demand Turn Up project saw National Grid and Western Power Distribution come together in an attempt to share DSR resources [46]. This is the first time a balancing service has been shared between two parties. National Grid and WPD were seeking similar types of service. The use case for WPD is in areas of high PV penetration. This concentration of PV may cause constraints when there is low demand. The idea is to procure an increase in demand to help ease this type of constraint. However, the requirement is highly locational since the additional load must be below the constraint on the network. National Grid called 10,800 MWh over 323 instructions with an average utilisation price of £61.41 /MWh. However WPD was limited by "low availability in the relevant areas". In a report for the Customer-Led Network Revolution project [67] Element Energy also state that the main difficulty in procuring DSR in the I&C sector is to do with gaining sufficient quantity of response in specific parts of the network. For DNO DSR location is a very significant factor. For the TNO location is sometimes considered for example for STOR [42] and the locational element of TNUoS charges. However, in general the location is of low or no importance to the TNO, for example frequency response services.

A CLNR report [67] cites lack of relationship and customer knowledge between the DNO and electricity users as a barrier. Whilst not a barrier in the uptake of DSR, the range of DSR required may be limited by a DNOs lack of confidence in the longevity of the DSR provision [67].

5.17. Summary

This chapter has given an overview of the different DSR services for the GB electricity system, including: Triads (not technically a service but a price signal in the billing structure for HH metered customers); DSR for system balancing; and potential requirement for DSR for the DNO. Market data and value information were given where possible. There was a section on DSR in the context of the commercial sector.

All the actual services described were for the SO, apart from the Triad charge which goes to the TNO. None of the services relate to (DNOs since they do not participate in DSR in a BaU sense.

The chapter finished with a section on the factors affecting DSR participation, looking at the point of view of the energy users, aggregators and the procurers of DSR.

It was seen that the financial benefit of STOR to the service providers is decreasing but the overall volumes are increasing [11, pp. 109]. It was noted that STOR is an exclusive service meaning that a STOR provider may not participate in Triad avoidance. The potential effects of this on a STOR provider are explored in Chapter 8 where the probabilities of STOR coinciding with Triad are analysed, taking into account energy recovery of DSR by demand reduction.

Chapter 6. The modelling software suite

6.1. Introduction

In order to answer the research questions in Chapter 1 a suite of software was developed by the author in MATLAB. The modelling suite provides a framework using time-based demand profiles connected to network models in order to assess interactions between different actors in an electricity system.

Many of the components of this software suite are developed in the object oriented paradigm. This chapter draws out the most important features of the classes developed which are used in work described in later chapters. Specific features or operations are referred to in context in the later chapters. A comprehensive overview of the all the classes is given in Appendix B.

This chapter starts with a brief overview of the Unified Modelling Language (UML). Then an overview of the most important classes that were developed by the author is given in the context in which they might be used.

6.2. The UML notation

The classes developed are described here using elements of the UML. Class diagrams are used with elements of inheritance, aggregation and dependency. This is not intended as a comprehensive introduction to UML. There are many books on UML such as given in [68].

A class is drawn as a box with up to three segments. The top segment indicates the name of the class, the middle segment indicates any attributes (known as variables in other programming regimes). The final segment indicates the names of any methods in the class (methods are known as functions in other programming regimes). The attribute and method sections are optional. A generalised class figure is shown in Figure 19.

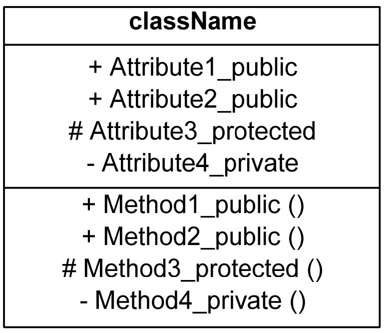


Figure 19 Class notation

On the left hand side are (optional) indications of the level of access to attributes and methods. The meanings of these is given in Table 15.

Symbol	Meaning
+	Public: any other class has visibility of this
#	Protected: only this class and any child classes have visibility of this
-	Private: only this class has visibility

Table 15 Meanings of visibility notations for attributes and methods

A dependency arrow indicates that one element requires another element for its specification or implementation as shown in Figure 20. The dependency arrow is a dashed line with an open arrowhead. Here the class "Dependent" requires knowledge of the class "Provider". If the specification of the class "Provider" were to change it may affect the class "Dependent".

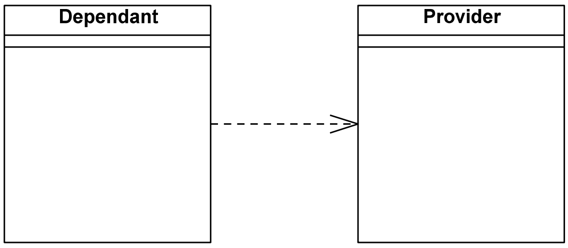


Figure 20 UML dependency relationship

A composition arrow indicates that a class made up of other classes. The composition relationship is indicated with a solid line ending with a filled diamond. For example in Figure 21 the arrow indicates that the "Company" is made up of one or a number of "Departments". The text '*1..**' indicates 1 to many (of the class "Department"). The asterisk is used to mean any number. Similarly the text '*1*' at the "Company" class indicates a single instance of that class. So the diagram should be read as: "one of class *company* is composed of one or more *departments*".

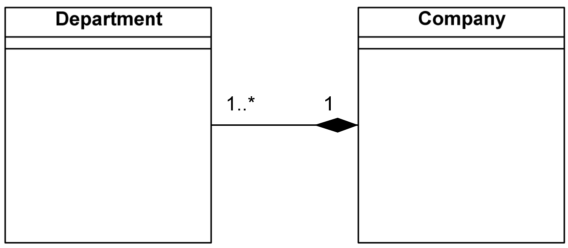


Figure 21 UML composition relationship

An inheritance arrow as shown in Figure 22 indicates that a class inherits all the attributes and methods of the parent class. The arrow is a solid line ending in a closed arrowhead. Here a class representing a bank account is shown. The current account and savings account inherit the attributes (these could include name, address, account number) of the generalized bank account class as well as the methods for the generalized “Bank Account” class (these might be to handle deposits or withdrawals). The child classes “Current Account” and “Savings Account” may add their own attributes and methods. These could be an attribute of ‘overdraft limit’ on the “Current Account” class and a method ‘addInterest’ which calculates the interest on the “Savings Account” class.

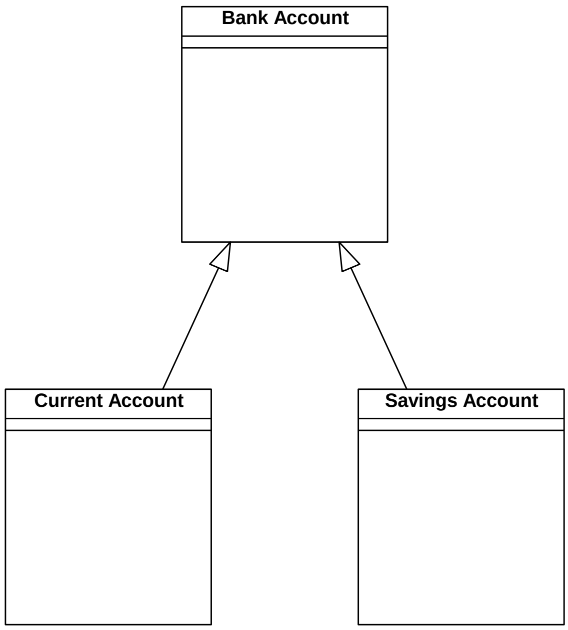


Figure 22 UML inheritance relationship

6.3. Overview of the main modelling components

It was necessary to develop a class that represented something that was connected to the network that demanded or supplied power from or to the network. The name given to this type of class is *powerAgent*. A number of these can be created in order to model demand profiles in different buildings or substations or at any level of aggregation as needed.

The central component of the software models is the *genericPowerAgent* class which inherits the *powerAgent* class. This class represents any agent that is able to connect to the electrical network and alter the power flow, such as a demand or generator. In this work it is only used to model demand. It can model demand response, have availability and utilisation prices for DSR and it’s location on the network can be specified. It is set up with date information, an expected demand profile and flexibility information. The *genericPowerAgent* and *powerAgent* class are described in more detail later but are introduced here in order to explain more clearly some other features of the modelling suite.

6.3.1. Calculating the cost of the electricity bill

Modelling the bill cost is required for the work in Chapter 8. In order to calculate the cost of electricity four classes were developed as shown in Figure 23. Three of these calculate different cost components whilst the *elecBill* aggregates the costs together. The *kwhCost* class calculates the energy cost. The *duosCost* class calculates the DUoS charges based on the red, amber and green time bands and the *triadClass* determines the cost of Triad based on the Triad periods and the Triad charge per kW.

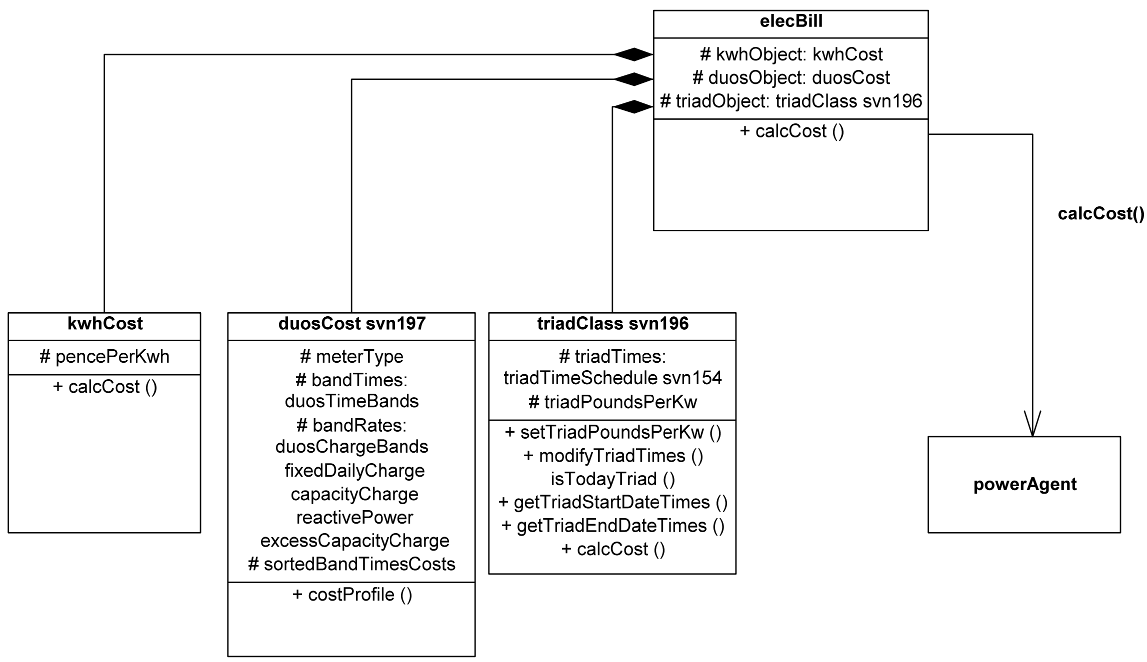


Figure 23 *elecBill* and associated classes

The method *calcCost* in the class *elecBill* takes a *powerAgent* class as an input and reads demand profile data from it. The *elecBill* attributes include the three classes associated with costs: *kwhCost*, *duosCost*, and *triadClass*. These are used to calculate the total bill for whatever *powerAgent* is taken as input. In this way it is possible to modify one particular parameter of the cost, say the times of the DUoS time bands whilst keeping all the other data the same. It is also possible to use the same billing cost values to calculate the bill for any number of *powerAgent*s.

It should be noted that this set of classes specifically models a GB electricity bill structure (e.g. it calculates DUoS and Triad charges). As it stands it is not generalizable to a different billing structure. In order to model a different billing structure a new set of child models would need to be developed and a new *elecBill* class would then be composed of these child classes and the calcCost() method would need to be written according to the new bill structure.

6.3.2. Modelling STOR calls

Classes were developed to model STOR such that a series of representative STOR call dates and times could be synthesized. STOR calls are modelled in Chapter 8 in order to assess the impact of a STOR call coinciding with a Triad period, in terms of the financial benefit to the STOR provider. The chapter provides more detail of how the model uses National Grid data to give a representative synthesis of STOR calls. In order to model STOR calls, parameters such as the number of expected calls in a year and information about the probability of calls at different dates and times of day are required.

The *storWindows* class contains the STOR season dates for a particular STOR year and can be interrogated in various ways, for example, to determine whether a particular date and time is within a STOR window, whether it is a working day or not (the STOR definition working days includes Saturdays), and which season it is in.

After a *storWindows* object has been created it can be used as an attribute in the *storSchedulerTemplate* as shown in Figure 24. Other attributes in this class define the probability that a STOR call will occur in a particular season and the number of STOR calls that would be expected over the STOR year. This class cannot be instantiated as an object, however the class *storSchedulerFixedDur,* which inherits the *storSchedulerTemplate,* can be instantiated. This class models the timing of STOR calls of a fixed duration.

The method *isTodayStorDay* evaluates whether STOR was called on a particular day, and returns this as a Boolean value. To do this it calls the method *setOrGetStorTimesToday*. This method checks to see if the date given has already been evaluated as to whether it is a STOR day or not. If it hasn't previously been assigned then the algorithm decides whether it is a STOR day or not based on a stochastic process based on National Grid STOR data (see section 8.2). The time of any call is stored. If it has previously been determined whether or not it is a STOR day then the method simply returns that (Boolean) value.

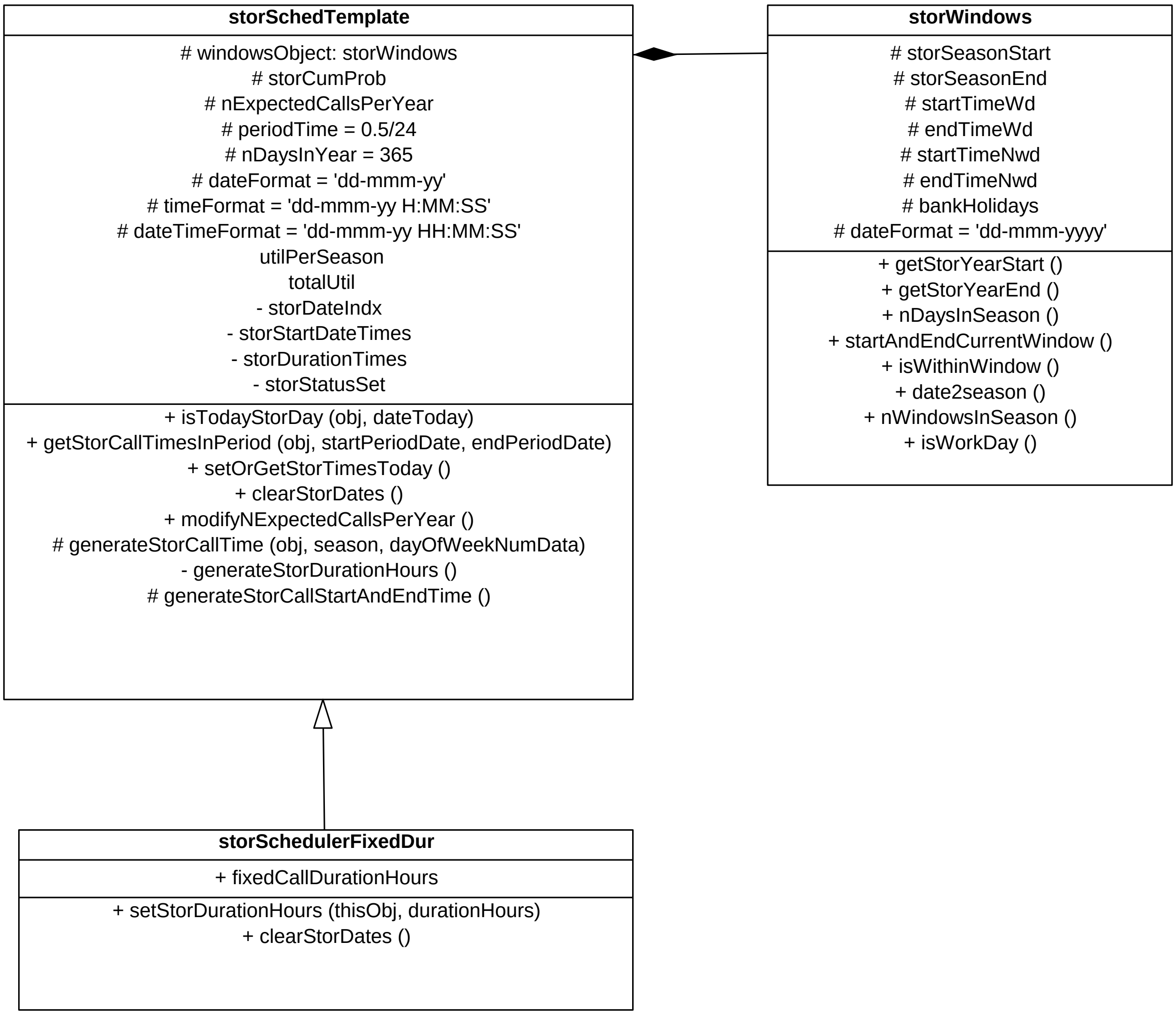


Figure 24 Classes associated with *storSchedulerFixedDur*

6.3.3. The *powerAgent* class

Modelling network connected demand is used in the work in Chapter 10. As stated previously the powerAgent class was developed to represent any agent that is able to connect to the electrical network and alter the power flow. The *powerAgent* class and its associated classes are shown in Figure 25 The *powerAgent* class was designed such that it contains expected and actual values for various parameters. The expected values are written into an object of this class but the actual values start off empty. When certain methods are evoked in the class the expected values are copied to the actual values for the given time period (that time period is then conceptually in the past). The motivation for this was that the model might be used to apply an operational decision ahead of time based on an expected flexibility but then that flexibility may change before the operation due to a second operation. Note that a negative flexibility means that demand can be reduced.

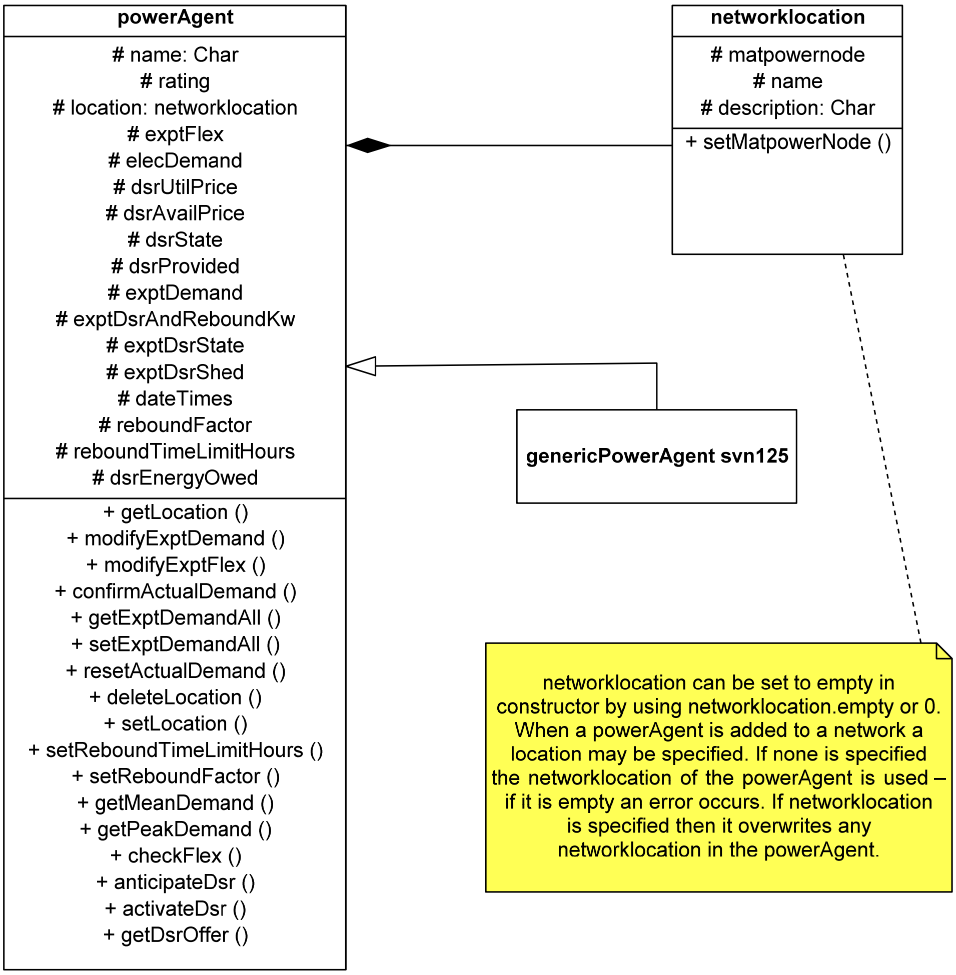


Figure 25 The *powerAgent* and its associated classes

The attributes which have a time dimension such as demand (including *exptDemand*, *elecDemand*), flexibility (*exptFlex*) and DSR parameters (including *exptDsrAndReboundKw, exptDsrState, exptDsrShed)* are referenced to the column vector *dateTimes*. The time step (or time resolution) of *dateTimes* for different objects does not have to be equal. This allows for *powerAgents* with different data resolutions to be used in the same model.

There are three methods associated with accessing the expected and actual values:

- checkFlex
- anticipateDsr
- activateDsr

The method *checkFlex* will interrogate the flexibility of the *powerAgent* without taking any action. The *anticipateDsr* method will modify the expected values in anticipation of a DSR call in order that any future actions can be based on updated future expected values. Finally the method *activateDsr* takes the results of any prior actions which have altered the expected values and determines how the *powerAgent* responds – then that time period is in effect in the past. This is summarized in Table 16.

	modifies	
method	expected demand	actual demand
checkFlex	-	-
anticipateDsr	✓	-
activateDsr	-	✓

Table 16 Summary of how expected and actual values are modified by various methods

In Matpower each bus is defined by a number but the *powerNetwork* class uses a custom data-type called *networkLocation* to define each bus and a pair of *networkLocation* classes to define a branch. This data-type includes the Matpower bus number and a text name and (optional) description, as shown in Figure 25. A list of network locations is kept in attribute *busLocationList* which is a row vector (1xn) of *networkLocation* classes.

6.3.4. The powerNetwork class

A distribution network model is used in conjunction with *powerAgent* objects and a *networkRunner* object for the work in Chapter 10. In order to run power flow analysis a MATLAB class was developed which interfaces to and runs Matpower [1]. An instantiation of this class has Matpower data structs as attributes to represent the impedance model of the network. This is shown in Figure 26. It also contains all the Matpower constants which makes it easier to write and read code that accesses Matpower.

A UML diagram of the class is shown in Figure 26. A *powerNetwork* has a method for running a power flow directly, but there are several other methods which will also invoke the power flow method, such as checking for network constraints, losses or bus voltages on the network. The class keeps a track of changes to the network in order to know whether the stored power flow results are up to date.

There are two methods for checking for constraints. One of these stores all the data about the network and the other solely ascertains whether or not there was a constraint. The reason developing these two methods was to save time when checking for constraints multiple times when the network state information was not required.

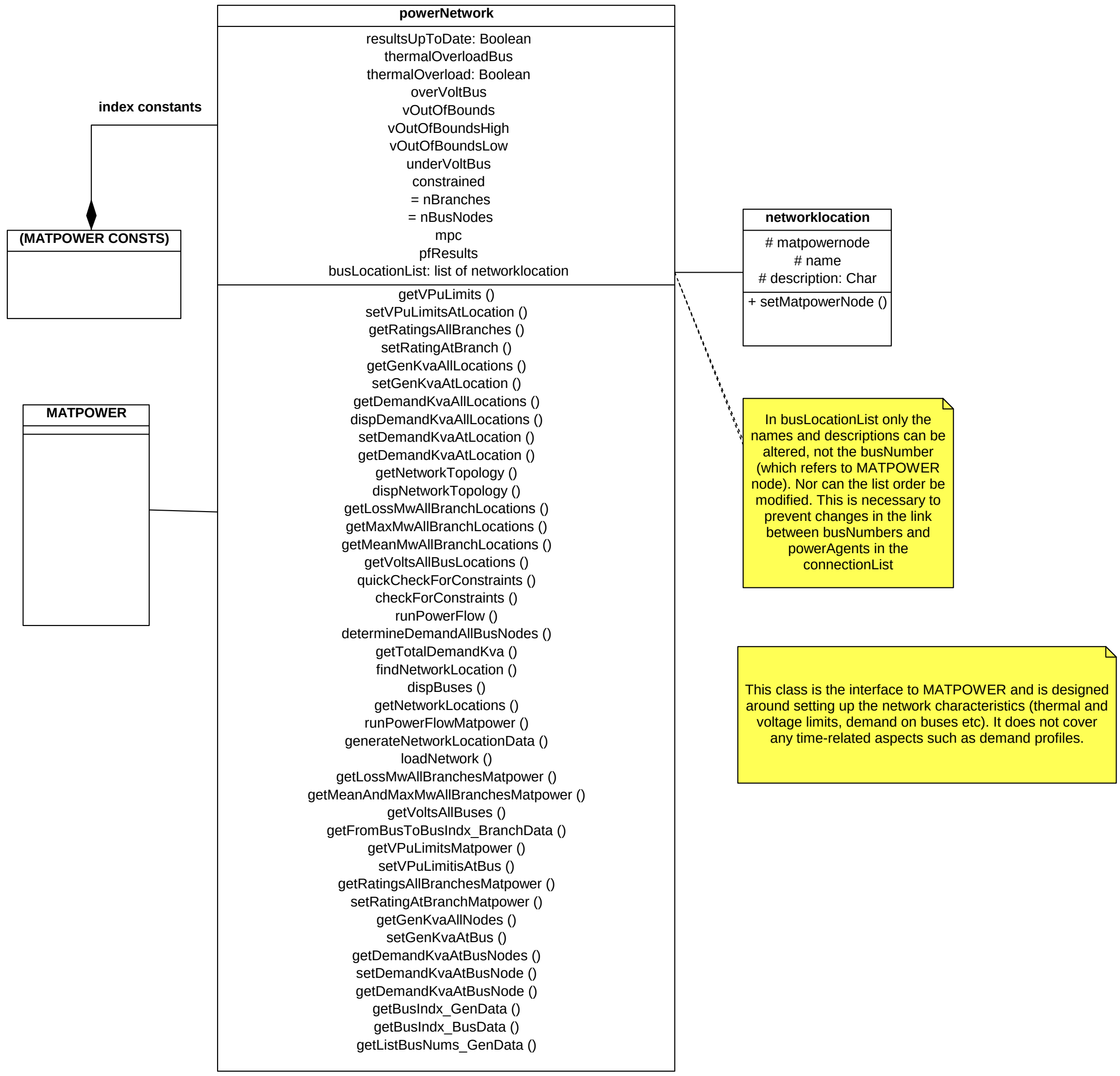


Figure 26 UML diagram of the *powerNetwork* class

6.3.5. The networkRunner class

The *networkRunner* class was developed so that power flow results could be obtained for data which varies with time, rather than just at a single point. This is required for work in Chapter 10. This class integrates the *powerNetwork*, the *powerAgents* and their *networkLocations* and manages the connections as shown in Figure 27.

A more detailed UML diagram for the *networkRunner class* this is shown in Figure 28. When a *networkRunner* invokes a power flow it sets attributes that begin with the text *"output..."*and "*constraints...*" which store network information that varies with time and information about constraints respectively. The constraint information stored is the date and time of the constraints, constraint locations, the type (thermal or voltage) and the total demand on the network at the time of the constraint. There is also a method for running a power flow without storing the network information, as with the *powerNetwork* class.

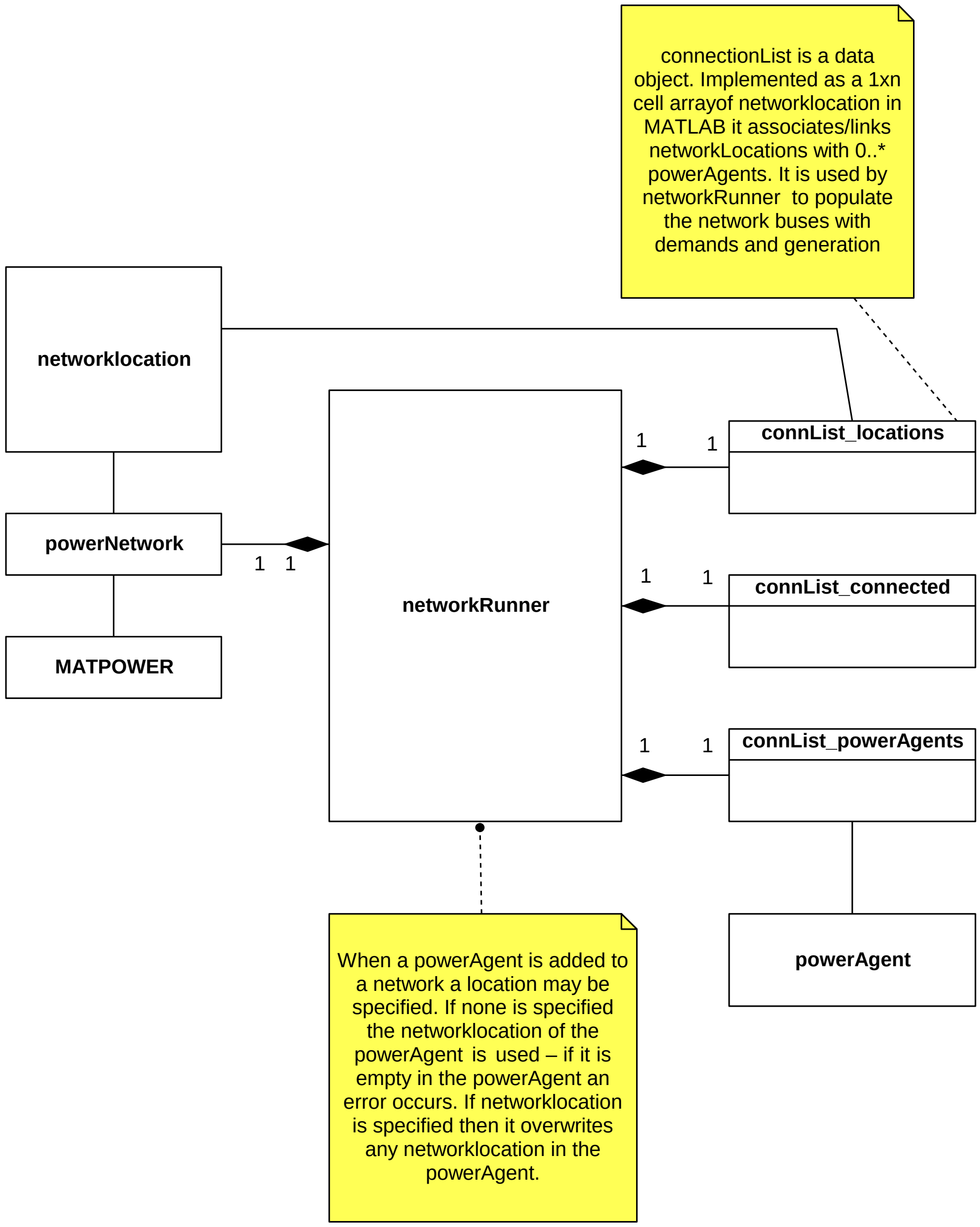


Figure 27 The *networkRunner* class and associated classes

networkRunner
outputMeanBranchPowerProfileMw outputMeanBranchPowerFromToLocs outputMaxBranchPowerProfileMw outputMaxBranchPowerFromToLocs outputDemandAtBusesKva outputDemandAtBusesKvaBusLocs outputVoltsPuProfile outputVoltsBusLocs outputBranchLossesKva outputBranchLossesKvaFromToLocs outputDateTimes constraintsDateTimeList constraintsLocList constraintsTypeList constraintsTotalDemandKva dateFormat = nBusNodes = nBranches = busLocationData
runNetworkCheckConstraintOnly () runNetworkAllData () removePowerAgentFromLocation () addPowerAgentToLocation () clearAllConstraintData () dispConstraintsLis () getConstraintsList () listPowerAgentsOnEachBus () listBranchNames () listBusNames () getDemandAtBusesKva () getBranchLossesKva () getMeanPowerProfileMw () getMaxPowerProfileMw () getVoltsProfile () clearAllOutputData () getPowerAgents () setDemandsOnBusesByInterrogatingPowerAgents () deleteAllGeneration () deleteAllDemand_Matpower () connIndx_GetIndxForLocation () connList_GetIndxForPowerAgent () connList_CheckPowerAgentDuplicate ()

Figure 28 The attributes and methods of the *networkRunner* class

6.3.6. Classes blockprofile and dsrblockdata

The *blockprofile* class is a simple way to specify a constant power reduction or increase for a period of time. It is created with the start and end times and the kW value with negative values meaning a demand reduction. The duration and kWh are dependent variables meaning that they are calculated whenever they are accessed.

The *dsrblockdata* class is a convenient way to specify a period of fixed kW DSR. This class is used to model DSR due to STOR in particular Chapter 8 and generic DSR in Chapter 10. It inherits the attributes from the *blockprofile* class and adds a *networklocation*. It should be noted that this class models a constant kW demand reduction with instant ramp-up and ramp-down times. A real demand reduction is likely to have a varying kW reduction, with respect to its baseline demand and may have a finite ramp up and ramp down time.

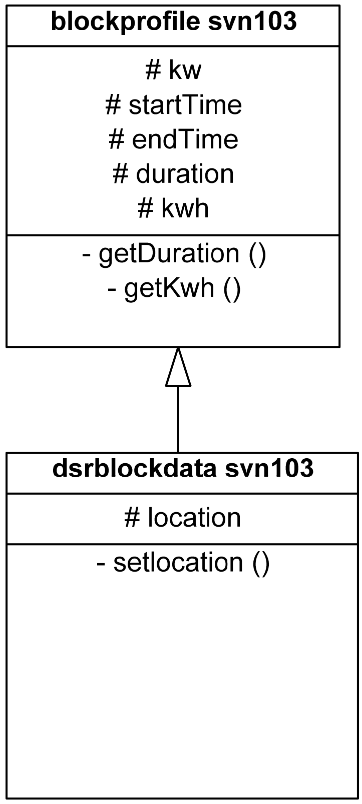


Figure 29 Block profile and dsrblockdata classes

6.4. Summary

This chapter has introduced the software suite developed by the author in order to answer research questions around DSR and sequential network power flows. The software was written in Matlab and the network power flows use Matpower [1]. Appendix B gives detail on all the classes developed.

Chapter 7. Cost benefit analysis of using standby generation for Triad avoidance

7.1. Introduction

The work in this chapter is based on a conference paper by the author [38]. The work evaluates the cost benefit of using a building's emergency standby generation in order to reduce the cost associated with Triads (see section 5.1), using actual demand data from a university building. Emergency standby generation is used to supply critical building demand in case of grid supply failure. Some modern systems use batteries to achieve this whilst other systems will automatically engage a Diesel generator set. This modelling in this chapter considers Diesel generator set systems.

Figure 30 shows the relevant actors and revenue flows for this work based on the revenue flow diagrams from section 2.3. The electricity user pays the retailer for: energy bought on the wholesale market; TNUoS charges and DUoS charges. For HH metered customers the TNUoS charge is Triads. If the electricity user reduces demand from the grid by using generation behind the meter the energy, TNUoS and DUoS charges will be reduced.

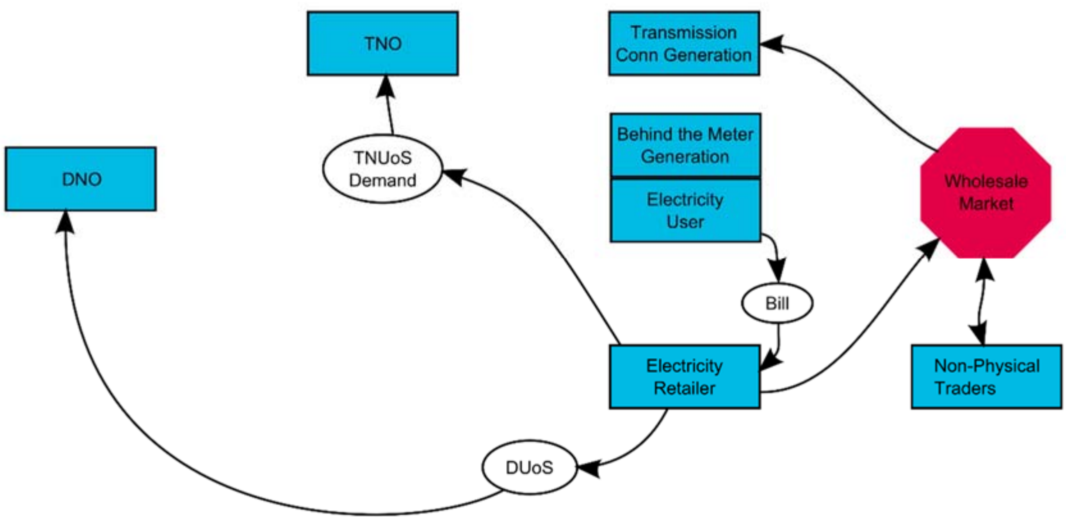


Figure 30 Actors and revenue flows relevant to the work in this chapter

It has been noted that emergency standby generators represent an under-utilised resource since the majority of their running hours are due to the maintenance schedule [69]. As described in section 5.1, Triad costs are a form of peak pricing for HH metered customers. Triad periods are not known in advance but some suppliers and other companies provide a Triad warning service so that electricity users can reduce their demand in order to try and mitigate the Triad charges. The revenue from Triads, along with other TNUoS charges, are used to compensate the TNO for the use of their assets.

The work described in this chapter develops models for costs associated with energy use, distribution use of service charges, Triads and emergency standby generator costs. The models use data from a university building, including HH demand data, bill data and the specifications of the emergency standby generator. The CO_2 emissions are also calculated.

Section 7.2 describes the revenue flows associated with using an emergency standby generator for Triad reduction. Section 7.3 gives an overview of the model and the sub-sections describe each part of the model in more detail. Section 7.4 sets out the method including the input parameter set. The results are given in section 7.5 and finally in section 7.6 there is a discussion of the results.

7.2. Description of revenue flows associated with the case study

Figure 31 shows the revenue flow for Triad avoidance by the use of emergency standby generation. This includes the features from the revenue flow diagrams for energy and use of system and adds revenue flows for the generator running costs. Maintenance costs are not shown

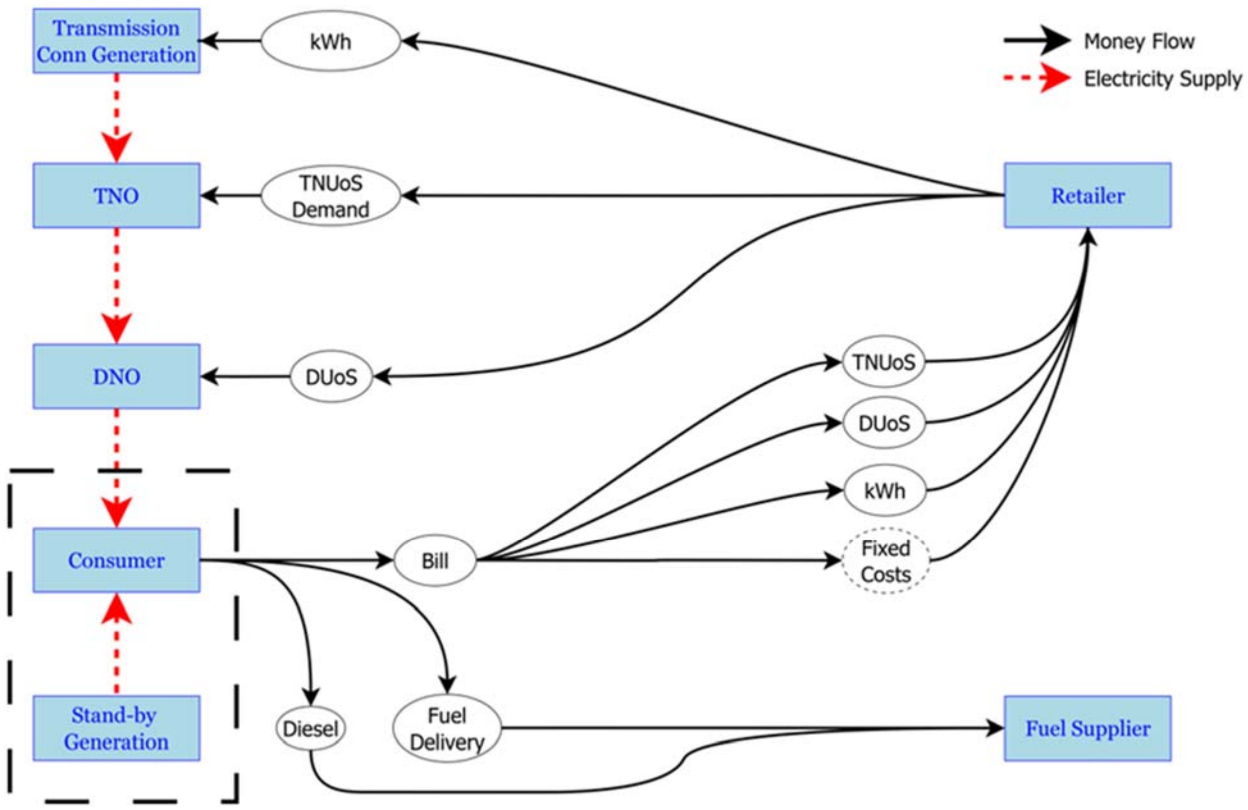


Figure 31 Revenue flow for Triad avoidance using Diesel emergency standby generation

7.3. Model description

Figure 32 shows how the model is composed to give the costs of running the emergency standby generator for Triad avoidance. The costs evaluated are:

- Generator fuel costs
- Electrical energy costs
- Triad charges on the electricity bill
- DUoS charges on the electricity bill

The inputs to the model are:

- emergency standby generator operating periods
- Representative demand profile during the Triad season without running the emergency standby generator
- Triad periods
- DNO Red, Amber and Green time bands
- Costs for fuel
- Electricity tariffs for energy, DUoS and Triad

The energy demand function calculates the cost of the energy consumed, cost of Carbon Reduction Commitment (CRC) and estimated CO_2 emissions. The DUoS function calculates the use of system costs for the distribution network based on the demand profile and DUoS time bands and tariffs. The Triad function uses Triad dates and times from 2013/14 and the demand profile to calculate the Triad charges. The generator function calculates a new demand profile, the fuel costs, and CO_2 emissions from a set of Triad warning data. The new demand profile is based on the original demand profile reduced by the power output of the generator.

There are other charges which are not included in the model since they are not influenced by the use of intermittent emergency standby generation:

- fixed daily charge (p/MPAN/day)
- capacity charge (p/kVA/day)
- reactive power charge (p/kVA)
- monthly charge
- settlement charge
- Feed in Tariff charge

7.3.1. Energy model

For HH metered customers the output from the meter is the average energy consumed for the previous half-hour. In the model the HH demand in kWh is referenced by date, d, and HH period number, h ($1 \leq h \leq 48$) :

$$E_{\mathrm{METER}} = f(d, h)$$

The total energy consumption, E_{TOT} in kWh, between two dates is given by:

$$E_{\mathrm{TOT}} = \sum_{d=start}^{enddate} \sum_{h=1}^{48} E_{\mathrm{METER}}(d, h)$$

The energy tariff, T_{CONS}, is single valued and the energy charge, C_{KWH}, is given by:

$$C_{\mathrm{KWH}} = T_{\mathrm{CONS}} \times E_{\mathrm{TOT}}$$

where C_{KWH} is the cost of the energy consumed in £

T_{CONS} is the demand tariff in £/kWh

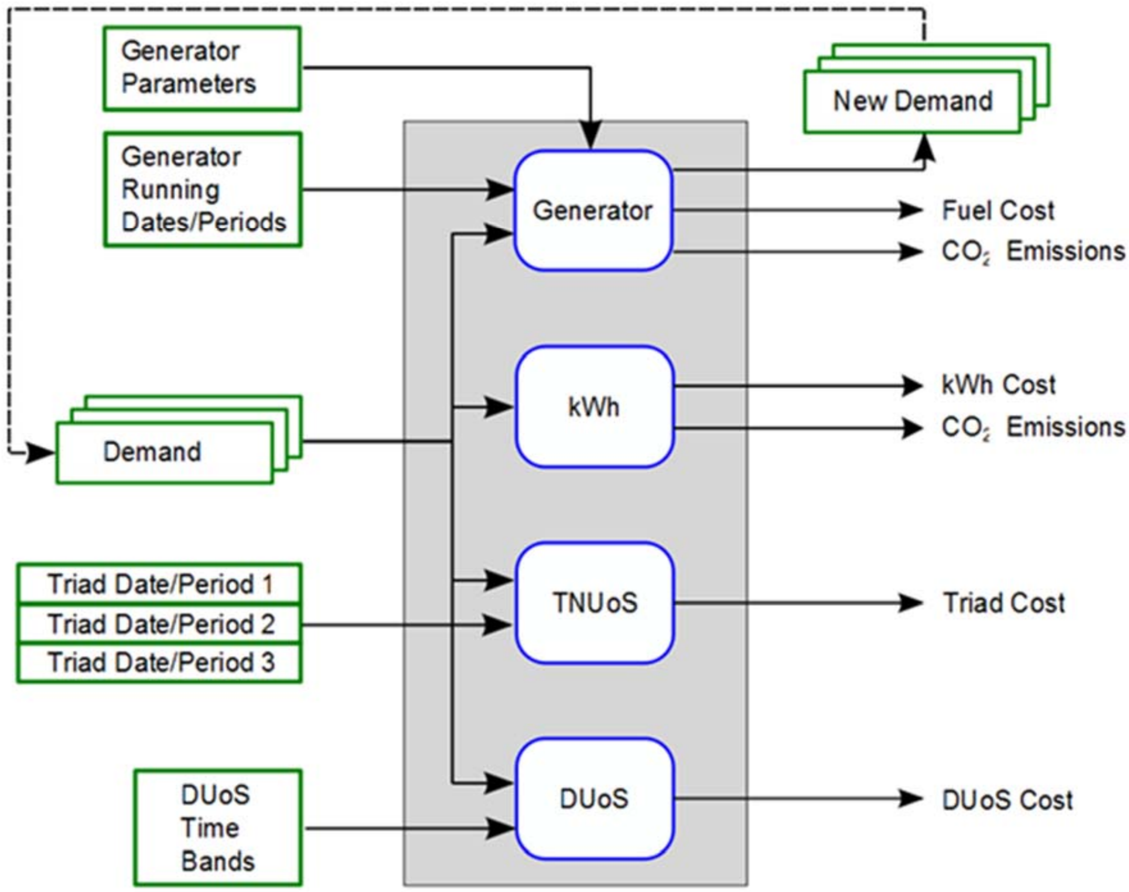


Figure 32 Cost model for the use of emergency standby generation for the reduction of Triad demand

7.3.2. Distribution Use of Service Model

As discussed in section 2.3.2.2, distribution use of system charges are based on energy consumption and time of use. There are three time bands: Green, Amber and Red which apply over the whole year. The time bands and tariffs for Northern Powergrid are given in [70] and are shown in Table 17.

The (peak) Red time band for Northern Powergrid is 16:00 – 17:30 Monday to Friday. Since all the Triad periods with one exception since 1973 occurred during this time, it is likely that the DUoS savings will be in the red band. However, this is not assumed in the model.

	Red Time Band	Amber Time Band	Green Time Band
Time	16:00 - 19:30	08:00 - 16:00 19:30 - 22:00	00:00 - 08:00 22:00 - 24:00
HH Periods	33 - 39	17 – 32 40 - 44	1 – 16 45 - 48
Tariff rate	9.072 p/kWh	1.097 p/kWh	0.121 p/kWh

Table 17 DUoS tariffs for Northern Powergrid [70]

The energy consumption in each time band is given by the following three equations:

$$E_{\mathrm{RED}} = \sum_{d=start}^{enddate} \sum_{h=33}^{39} E_{\mathrm{METER}}(d,h)$$

$$E_{\mathrm{AMBER}} = \sum_{d=start}^{enddate} \sum_{h=17}^{32} E_{\mathrm{METER}}(d,h) + \sum_{d=start}^{enddate} \sum_{h=40}^{44} E_{\mathrm{METER}}(d,h)$$

$$E_{\mathrm{GREEN}} = \sum_{d=start}^{enddate} \sum_{h=1}^{16} E_{\mathrm{METER}}(d,h) + \sum_{d=start}^{enddate} \sum_{h=45}^{48} E_{\mathrm{METER}}(d,h)$$

Then the cost of the DUoS charges, C_{DUOS}in £, is given by:

$$C_{\mathrm{DUOS}} = (E_{\mathrm{RED}} \times T_{\mathrm{RED}}) + (E_{\mathrm{AMBER}} \times T_{\mathrm{AMBER}}) + (E_{\mathrm{GREEN}} \times T_{\mathrm{GREEN}})$$

where T_{RED} , T_{AMBER} and T_{GREEN} are the DUoS time band tariffs in £/kWh.

7.3.3. Transmission network charges model

TNUoS charges (see section 2.3.2.1) discourage electrical demand at peak times. This has the benefit of increasing network reliability and reducing losses. As stated in section 5.1, Triads are *"the three half hour settlement periods of highest transmission system demand during November to February of a Financial Year, separated by 10 clear days."* [10]. For HH metered customers the TNUoS charges are in the form of Triads. For the year 2013/14 the Triad charge, T_{TRIAD} , was 22.35 £/kW in the Northern region. Note that the Triad charge for HH metered customers is based on the average power (not energy) demand during the Triad periods. (However, for non-half hourly customers the charges are based on energy consumed with respect to a demand profile class rather than power). The Triad charge, C_{TRIAD}, is given by the equation below, where the energy value inside the summation is divided by half an hour to convert from HH energy to power value:

$$C_{\mathrm{TRIAD}} = T_{\mathrm{TRIAD}} \times \frac{1}{3} \sum_{n=1}^{3} \frac{E(d(n), h_{\mathrm{TRIAD}}(n))}{0.5}$$

where T_{TRIAD} is the Triad tariff, $E(d,h)$ is the demand energy on day d and half-hour h and n is and index for the Triad.

7.3.4. Emergency standby generator cost model

A generator running profile is created based on an index which defines whether the generator is running or not on a particular date, d and half-hour period, h. The energy contribution from the generator, $G(d,h)$ in kWh, is:

$$G(d,h) = \begin{cases} 0, & I_{\mathrm{GEN}}(d,h) = 0 \text{ or "off"} \\ P_{\mathrm{E}} \times 0.5 \text{ hours}, & I_{\mathrm{GEN}}(d,h) = 1 \text{ or "run"} \end{cases}$$

Where P_E is the maximum continuous rating of the generator.

The total running time of the generator, t_{GEN}, is given by:

$$t_{\mathrm{GEN}} = 0.5 \times \sum_{d=start}^{enddate} \sum_{h=1}^{48} I_{\mathrm{GEN}}(d,h)$$

Then the cost of Diesel fuel, C_{FUEL}, can be calculated as:

$$C_{\mathrm{FUEL}} = t_{\mathrm{GEN}} \times F_{\mathrm{CONS}} \times C_{\mathrm{DIESEL}}$$

where F_{CONS} is the fuel consumption rate of the generator at maximum continuous rating in L / hour and C_{DIESEL} is the cost of the Diesel in £ /Litre.

The energy output, E_{GEN}, of the generator is:

$$E_{\mathrm{GEN}} = P_{\mathrm{E}} \times t_{\mathrm{GEN}}$$

7.4. Method and parameter values

This section describes the parameters used for this case study and verifies the model against the actual electricity bill for the building. The average energy demand tariff in the UK was 8.48 pence/kWh (excluding taxes) for large consumers from July – December 2013 [71, Table 5.6.3 (electronic version only)]. However the demand tariff shown on the bill for the university building in October 2013 was 6.849 pence/kWh. Using the average value for the UK would give increased energy costs in the model but would exaggerate the savings due to using emergency standby generation. For this reason the value of 6.849 pence/kWh was used.

The emergency standby generator in the university building is a Perkins 1000 Series 1006TAG Diesel. Parameters from the datasheet [72] are given in

Table 18. The average cost of Red Diesel between November 2012 – October 2013 from [11] is 70.09 pence/Litre. This has a standard deviation of 2.0 pence/Litre meaning that 95% of values are between 68 and 72 pence/Litre, assuming a normal distribution. This is a range of about 6%. For the model a value of 70 pence/Litre is used. There are additional operating costs for fuel delivery, an increased cost for running-hours based maintenance and a small additional manpower cost for operation which have not been modelled due to lack of data. There is also an unknown capital cost associated with connecting the generator to the grid.

Type of Operation	Typical Generator Output (Net)		Fuel Consumption
	kVA	kWe	Litres / hour
Prime Power	135	108	31.5

Table 18 Data for Perkins 1000 series 1006TAG (1500 rpm) Generator [72]

The cases considered are for three, two and one Triads being correctly predicted and for a total generator running time of 30 hours and 25 hours, giving a total of six cases in addition to the baseline case where emergency standby generation is not used. The baseline case considers the demand profile as measured, without the use of emergency standby generation to mitigate Triads.

The generator model was run for the six cases and six new demand profiles are created. The Triad periods for 2013/14 were used for the Triad costs. Since there was no data available for the Triad warning periods the peak day data of non-Triad days was used in descending order of kW to represent the Triad warning periods when the generator would also be running.

7.4.1. Model verification

The baseline model (without the emergency generator) was run from 1st November 2013 to 28th February 2014 and the Triad and kWh costs were compared to the costs obtained from the actual bill. The modelled costs agreed with the bill values to within 0.00004 % and 0.0025 % respectively.

7.5. Results

The model was run for a year from 1st March 2013 to 28th February 2014. For 30 hours of Triad warnings the electricity bill savings achieved against the baseline costs for hitting one, two or three Triad periods are given in Table 19.

	Baseline case	3 Triad periods hit		2 Triad periods hit		1 Triad period hit	
	Cost	Cost	Saving	Cost	Saving	Cost	Saving
Generator Fuel	N/A	£661.50	N/A	£661.50	N/A	£661.50	N/A
kWh	£85,019.00	£84,797.00	0.3%	£84,797.00	0.3%	£84,797.00	0.3%
Grid CRC	£8,058.80	£8,037.70	0.3%	£8,037.70	0.3%	£ 8,037.70	0.3%
Triad	£6,215.30	£3,801.90	38.8%	£4,606.40	25.9%	£5,410.80	12.9%
DUoS	£23,000.00	£22,782.00	0.9%	£22,782.00	0.9%	£22,782.00	0.9%
Total	£122,293.10	£120,080.10	1.8%	£120,884.60	1.2%	£121,689.00	0.5%
	Total Savings						
	£0.00	**£2,213.00**	**1.8%**	**£1,408.50**	**1.2%**	**£604.10**	**0.5%**

Table 19 Results for running generator for 30 hours

There is a small saving on the Carbon Reduction Commitment (CRC) cost from running the generator as the CRC is no longer charged on Diesel [12]. The estimated CO_2 emissions when the emergency standby generator is not used is 672 tonnes. If the generator is operated the estimated emissions increase to 674 tonnes.

Table 20 shows the results for 25 hours of warning periods.

	Baseline case	3 Triad periods hit		2 Triad periods hit		1 Triad period hit	
	Cost	Cost	Saving	Cost	Saving	Cost	Saving
Generator Fuel	N/A	£661.50	N/A	£661.50	N/A	£661.50	N/A
kWh	£85,019.00	£84,834.00	0.2%	£84,834.00	0.2%	£84,834.00	0.2%
Grid CRC	£8,058.80	£8,041.20	0.2%	£8,041.20	0.2%	£8,041.20	0.2%
Triad	£6,215.30	£3,801.90	38.8%	£4,606.40	25.9%	£5,410.80	12.9%
DUoS	£23,000.00	£22,818.00	0.8%	£22,818.00	0.8%	£22,818.00	0.8%
Total	£122,293.10	£120,046.35	1.8%	£120,850.85	1.2%	£121,655.25	0.5%
	Total Savings						
	£0.00	**£2,246.75**	**1.8%**	**£1,442.25**	**1.2%**	**£637.85**	**0.5%**

Table 20 Results for running generator for 25 hours

Figure 33 shows the costs for energy and DUoS for each half hour period, referred to the left hand axis and the building demand in kWh referred to the right hand axis. The DUoS cost for the red band exceed the energy costs, whilst for the green band they are hardly perceptible on the scale of this graph. For comparison, if there were a Triad period at 17:00 the cost is calculated below:

The demand at 17:00 is:

$$\frac{140 \text{ kWh}}{0.5 \text{ h}} = 280 \text{ kW}$$

The Triad charge for that one Triad is

$$C_{\text{TRIAD}} = 22.35 \text{ £/kW} \times \frac{1}{3} \times 280 \text{ kW} = \text{£}2{,}086$$

To be clear, this is the cost of a single Triad. If the other two Triad periods have the same demand of 280 kW the total cost would be £6,258.

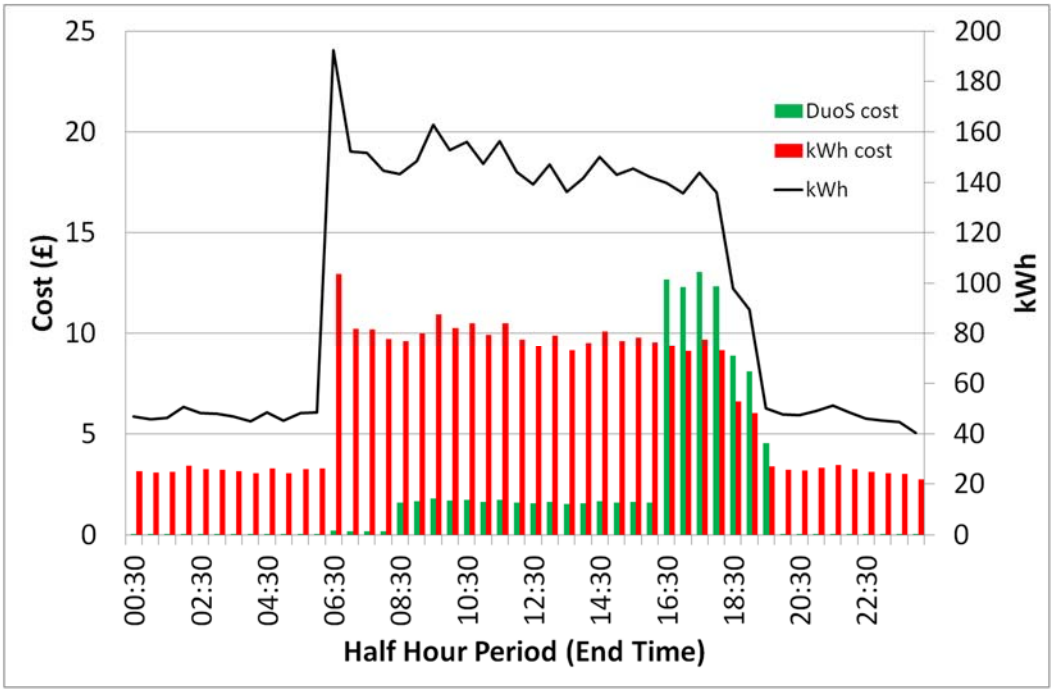


Figure 33 The cost breakdown (no Triad)

Figure 34 shows the relative costs in this model without Triad avoidance as a proportion of the total bill for the costs modelled. They are the values in the baseline case in Table 19. Triad accounts for more than 5% of the total bill. If three Triad periods are hit the relative proportion of Triad costs in the bill reduces to almost 3%.

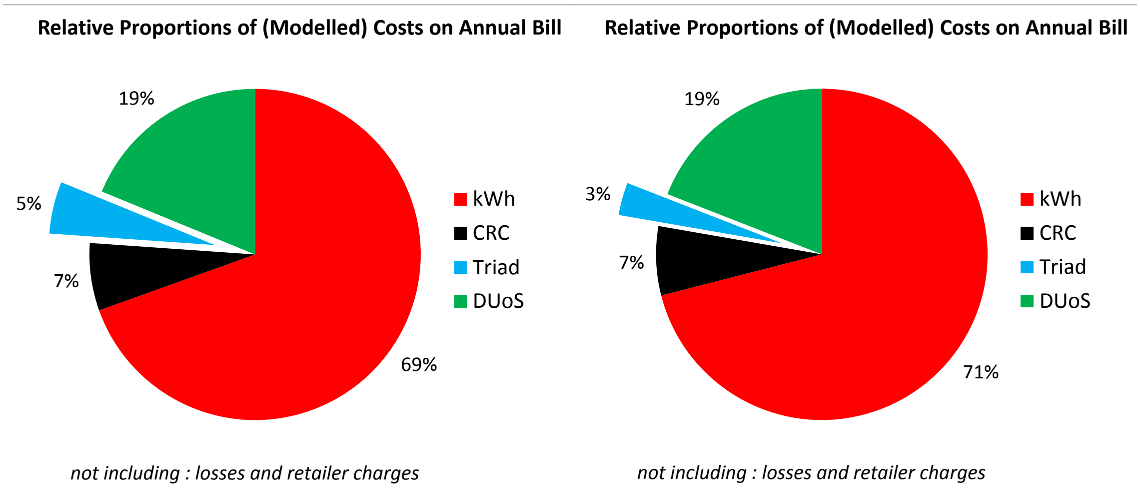


Figure 34 The relative proportions of costs in the annual bill for baseline (left) and 3 Triads hit (right)

CO_2 emissions are slightly increased by 2 tonnes (0.3%) but the cost of CO_2 emissions (CRC) is slightly reduced by 0.2%. The numbers are small but it is an example of how environmental regulation does not always have the desired effect.

7.6. Model and results limitations

Table 21 is a list of parameters required to do a cost benefit analysis for using emergency Diesel standby generation for the mitigation of Triad costs. It highlights the unmodelled parameters that were not available for this work.

The results in this chapter apply only to the building used, its current day demand and the rating of it's emergency generator. The results would be affected by changes in the DUoS charges or the timing of the DUoS price bands, price of red Diesel and the kWh charge for electricity. The fixed bill costs were not modelled.

Parameter description	**Included in modelling**	**Source of data**
Representative demand profile for the Triad season	Y	HH Metered values
emergency standby generator kW rating	Y	Nameplate
Fuel consumption	Y	Datasheet
Cost of red Diesel	Y	Mean price 2012/13
DNO Charges and time bands	Y	NPG DUoS tariffs [70]
Cost of grid connection for the emergency standby generator	N	
Cost of additional fuel delivery	N	
Cost of additional manpower to operate the generator set	N	
Fixed charges on electricity bill	N	

Table 21 Modelled and unmodelled parameters

7.7. Discussion

The average increase in Triad tariff is almost 15% per year and the value for 2014/15 is more than 20% more than the tariff for 2013/14. Whilst increasing Triad tariffs may increase the potential savings due to Triad demand reduction, the predictability of Triads may decrease. KiWi Power believes that Triad periods are becoming more random and suggests that one explanation of this is that there is a greater effort by users to shift demand away from Triad periods [37].

This study indicated that considerable savings on Triad charges are possible by running a grid connected emergency standby generator. However, the study does not include costs for fuel delivery and generator maintenance and operation (including manpower). There may be an impact on maintenance and lifetime due to additional running hours. On the other hand the emergency standby generator will likely have a maintenance schedule that involves running it a number of times during the year and the use of the generator to provide Triad avoidance could offset part of that maintenance effort. That is to say that running the generator for Triad avoidance could be counted as maintenance running.

The study also does not include the capital cost of connecting and synchronising the generator to the grid. The capital costs associated with a grid connection for this generator are not known, but they could have a significant impact on the payback time of the capital expenditure.

If the costs of grid connection, fuel delivery, generator maintenance and operation can be estimated accurately, the payback time can be estimated using the graph of cumulative savings in Figure 35 for Triad warnings of 25 and 30 hours and for 2 or 3 Triads hit.

The graph in Figure 35 indicates that the number of Triad warning hours has a significant impact on the savings compared to the number of Triads hit.

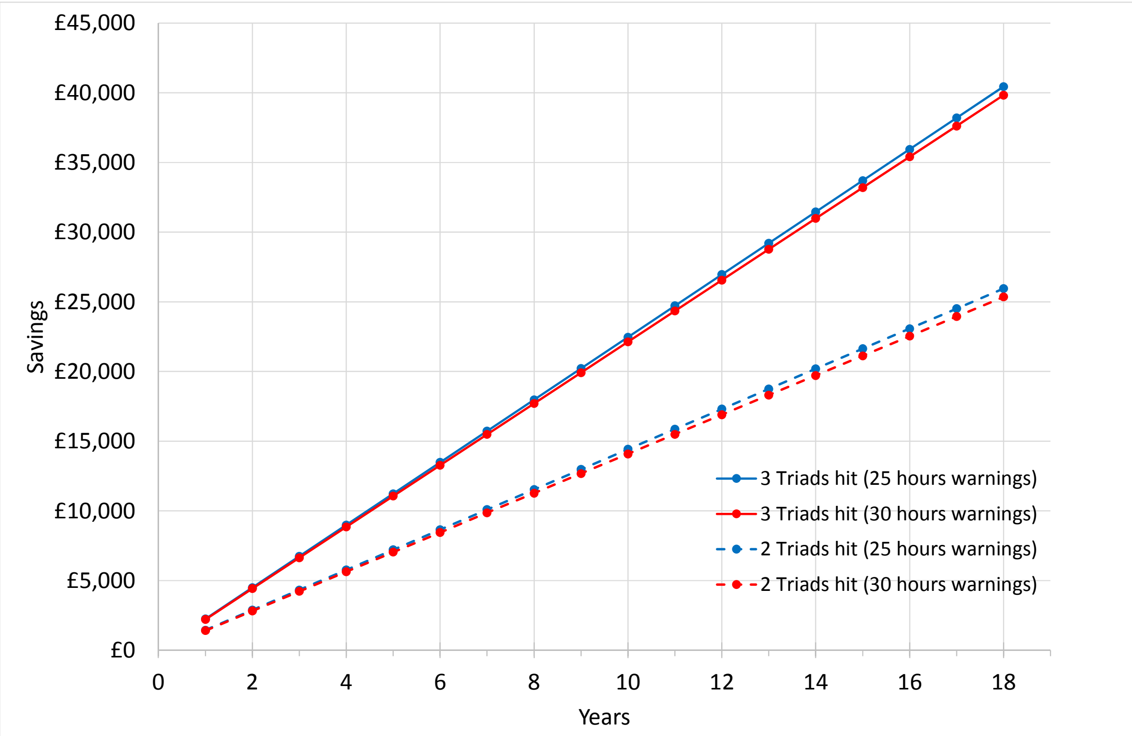


Figure 35 Cumulative graph of savings versus time for 2 and 3 Triads hit with 25 and 30 hours of Triad warnings

It should be noted that this graph applies only to the size of generator modelled.

Generator efficiency normally increases with rated power and therefore a larger generator should improve savings. For an emergency generator sized to meet critical load the power output is very likely to be less than the demand during forecast Triad periods, so although it could be used to mitigate Triad costs the Triad-chargeable demand is likely to be significant and energy saving measures should also be employed in a Triad avoidance regime.

Once the generator is grid connected it would be able to provide flexibility services to the grid, such as STOR via an aggregator. Some authors note that current policy favours standby generation over demand shifting for DSR [18]. The ability to provide other services would improve the case for grid connection.

7.8. Summary

The work has shown that the case for connecting emergency standby generation to the grid for the purpose of Triad avoidance depends on the cost of grid connection and the required payback time. The annual savings on the Triad cost are around 26 – 39 % for two or three Triads correctly predicted. Since the Triad is about 5 % of the total bill and accounting for fuel costs the total electricity bill saving is between 1 - 2 %, again for two or three correctly predicted Triads and not including the capital costs of grid connection.

Chapter 8. STOR and Triad coincidence

8.1. Introduction

STOR is a SO balancing service requiring a minimum response of 3 MW for at least 2 hours, however providers with a lower response may participate via an aggregator, see section 5.3. Triads, described in section 5.1, are a peak demand pricing mechanism. Demand during a Triad period incurs a significant additional cost on the electricity bill for HH metered customers. For this reason some electricity users aim to reduce their demand during expected Triad periods, this is known as *Triad avoidance*. The use of emergency standby generation for Triad avoidance was modelled in the previous chapter.

Figure 36 shows the actors and revenue flows relevant to the work in this chapter. The income from STOR is paid by the SO to provider either directly or via an aggregator to the electricity user. This payment is classed as a commercial service to a non-authorised electricity operator (i.e. an operator that is not subject to the BSC).

The electricity user is subject to Triad charges which form part of the bill paid to the electricity retailer. The Triad charges are paid by the electricity retailer as part of the TNOuS charges. Triad is described in detail in section 5.1.

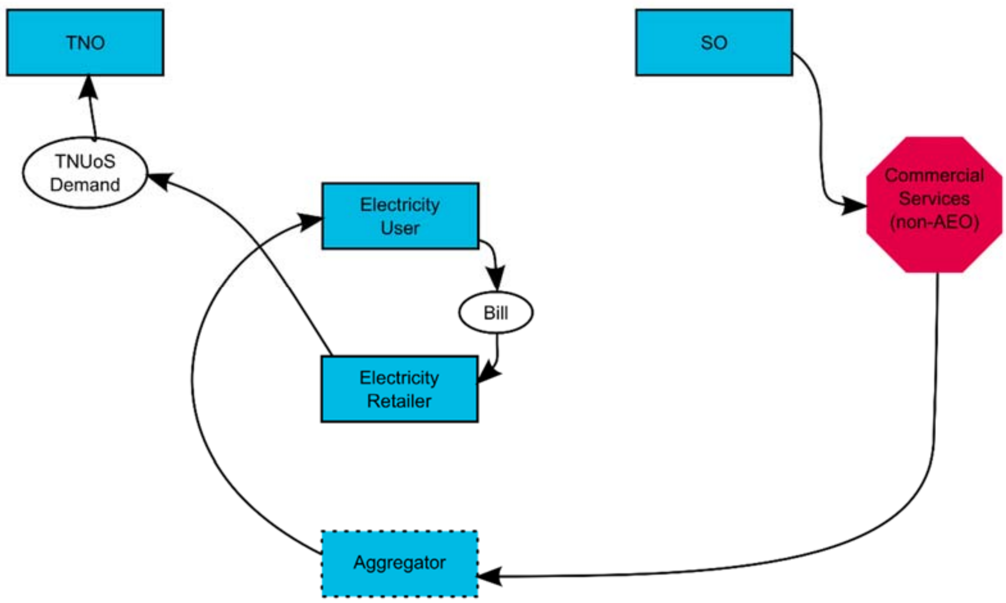


Figure 36 Actors and revenue flows relevant to this chapter

As noted in in section 5.3, the STOR service is exclusive meaning that providers may not participate in other services (either from third parties or from National Grid) that would interfere with their ability to provide STOR [42]. A report from the FALCON project noted that this is because National Grid pays a premium for STOR capacity (in the availability payment):

"...the exclusive nature of the contracts means that if being paid for STOR, a site should not operate any other ancillary services or cost avoidance schemes that require the same capacity capability" [73, page 21]

A response to a STOR call that overlaps with a Triad period would reduce the demand for that Triad compared to the demand if there were no STOR call. However, if the STOR response is provided by a sub-load with demand recovery (as discussed in section 4.3.2), it is possible that the demand recovery period would overlap with the Triad period and this may lead to an increased demand during a Triad period. For STOR provision by demand reduction using a sub load with demand recovery there are three possible outcomes in terms of Triad demand: it may increase, or decrease, or remain the same. The type and degree of the outcome would have different impacts on the bill cost and therefore on the total financial benefit of providing STOR.

This chapter evaluates the probability and magnitude of increased or decreased Triad demand due to STOR provision and the costs incurred with different demand recovery characteristics in order to evaluate a total cost benefit of providing STOR, including the STOR income generated. In order to evaluate the probabilities of STOR altering Triad demand, the work develops a model of STOR call dates and times and evaluates the effect of STOR on Triad and the cost benefit using Triad data from 2013/14. The work is also described in a paper written by the author [74].

8.1.1. Structure of the chapter

In section 8.2 the chapter describes the probabilistic model for STOR call timings and how National Grid data is used to determine the likelihood of a STOR call. In section 8.3 a model of demand response with demand recovery is developed and explained. For the experiment the parameter space and values are given in section 8.4 before the method is described in section 8.5.

The presentation of results is split into several sections. First the probability of Triad demand increase or decrease with different STOR durations and recovery characteristics is presented in graphs in section 8.6. In section 8.6.1 a discussion explains the features of the graphs. A second set of graphs, presented in section 8.7, show the extent of the change to Triad demand (in terms of kW) of these increases or decreases. Following this, section 8.8 shows the total cost benefit (relative to non-participation in STOR) for the different STOR durations and recovery periods, taking into account the energy cost, Triad cost, DUoS costs and STOR income. This is presented at different percentiles of cost benefit. In section 8.9 the spread of this cost benefit is given as histograms and the probability of negative, neutral and positive cost benefit is given in section 8.10. The results are summarized in section 8.11.

8.2. Modelling STOR call timings

The model of STOR call times has two stages. The first stage determines whether the given date is a STOR day or not. If it is a STOR day then the time of the STOR call is determined, otherwise there is nothing to calculate, since it is not a STOR day. This is shown in part of Figure 43 at the decision box ‘Is STOR called today?’.

8.2.1. Determining whether STOR is called on a given date

The STOR energy called by season is available from [75, 76] and is reproduced Table 22. The table does not include the utilisation for optional windows (OW), which are periods outside the standard STOR windows. The relative probability of STOR occurring during a particular season is determined by using the ratio of STOR energy called in that season and the total STOR energy over the whole year.

STOR Season	Dates	Total Utilised (GWh) (excludes OW)	STOR Hours in Season	Utilisation (MWh)/ Hours
7.1	01 April 2013 to 29 April 2013	24.7	251	98.4
7.2	29 April 2013 to 19 Aug 2013	74.6	1,207.00	61.8
7.3	19 Aug 2013 to 23 Sept2013	31.9	384	83
7.4	23 Sept 2013 to 28 Oct 2013	22.2	362.5	61.3
7.5	28 Oct 2013 to 03 Feb 2014	82.5	1,059.00	77.9
7.6	03 Feb 2014 to 01 April 2014	55.8	599	93.2

Table 22 STOR energy called by season (second column) [75, 76]

Multiplying this ratio by the number of expected calls in a year gives the probability, P_{S}, of a call in a particular season, S:

$$P_{\mathrm{S}} = \frac{E_S}{E_{\mathrm{TOTAL}}} \times N_{\mathrm{TOTAL}}$$

where E_S is the energy utilized in season S, E_{TOTAL} is the total energy used over the year, N_{TOTAL} is the total expected number of calls over the year. The probability, P_D, of a STOR call on a particular day, D, is given by:

$$P_D = \frac{P_S}{n_{\mathrm{DS}}} = \frac{E_S}{E_{\mathrm{TOTAL}}} \times \frac{N_{\mathrm{TOTAL}}}{n_{\mathrm{DS}}}$$

where n_{DS} is the number of days in a season.

To determine whether a particular day is a STOR day in the model, a random number with a value between 0 and 1 is generated and compared with P_D. If the random number is less than P_D it is deemed to be a STOR day. This gives a binomial distribution for the number of days STOR is called, N_{Total} , and this has a standard deviation of

$$\sigma = \sqrt{np(1-p)}$$

where n is the number of trials, and p is the probability.

8.2.2. Determining the time of a STOR call

The Short Term Operating Reserve Annual Market Report 2013/14 [76] gives the MWh provided by settlement period for each day and by STOR season. Figure 37 shows this for Mondays for the six seasons. Data from this report, available from reference [75], was used to produce the graph in Figure 38 which shows the MWh for Monday in season 7.5 on the left hand axis (black curve). Note that the data includes optional windows and there is some utilisation outside of the STOR windows. The cumulative utilisation, normalised from 0 to 1 is shown in the red curve and right hand axis of Figure 38. This cumulative probability is normalised between 0 and 1. Cumulative probability data was generated for all the days of the week. A call period can then be determined by generating a random number between 0 and 1 and using the normalised cumulative probability referred to the time of day axis. Figures 39 and 40 show graphs for Thursday and Friday. The STOR energy called during the second window on Friday is significantly higher.

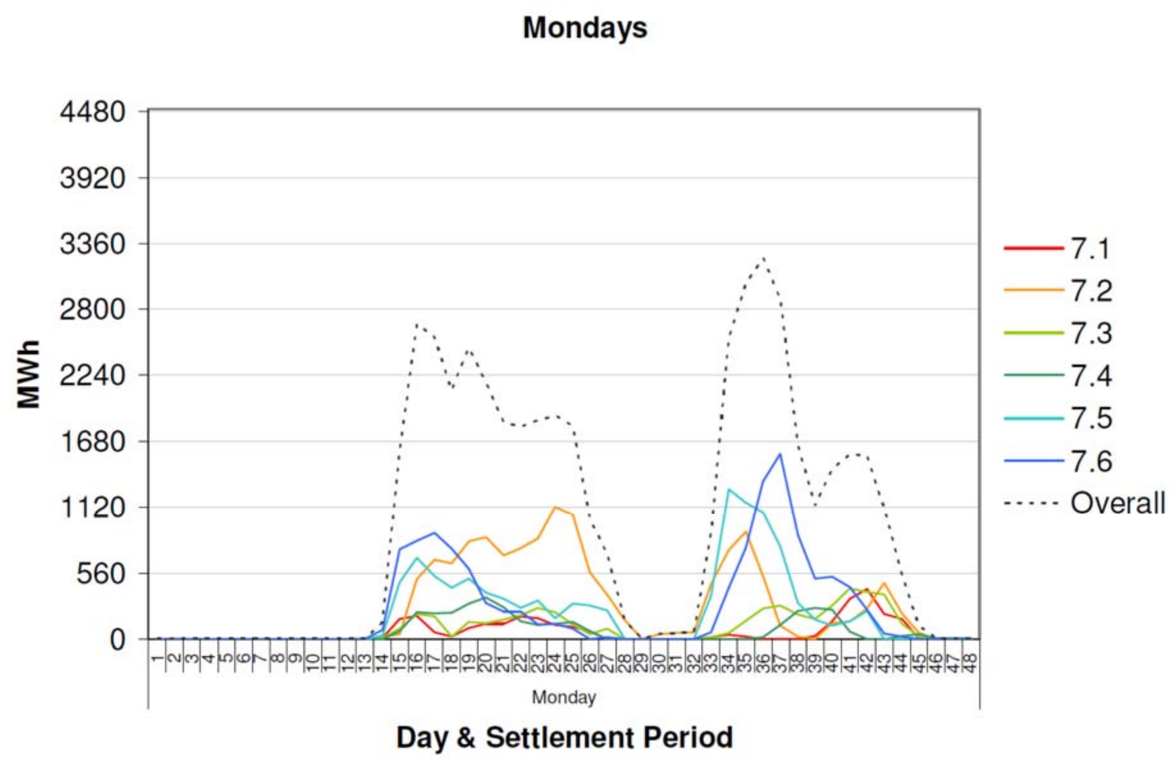


Figure 37 STOR energy called per HH period on Mondays for STOR seasons 7.1 to 7.6 [76]

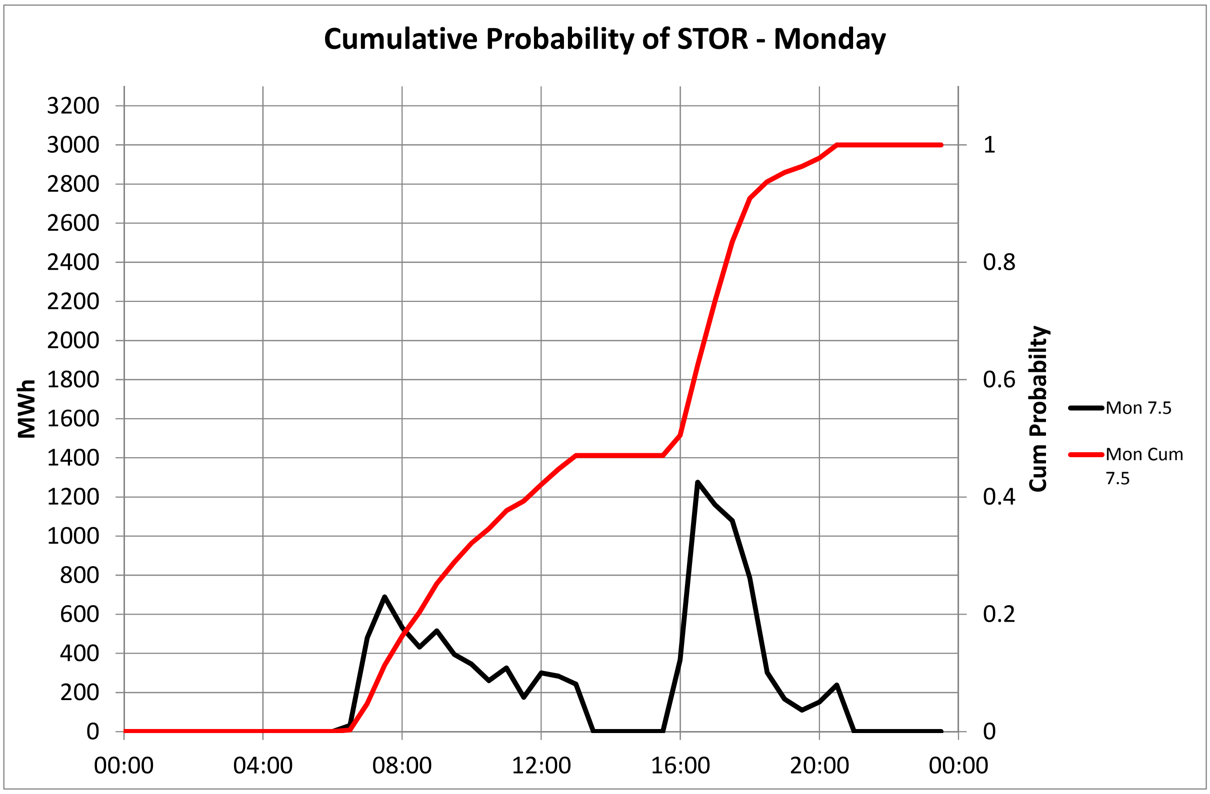


Figure 38 Calculation of cumulative probability of STOR for Mondays season 7.5

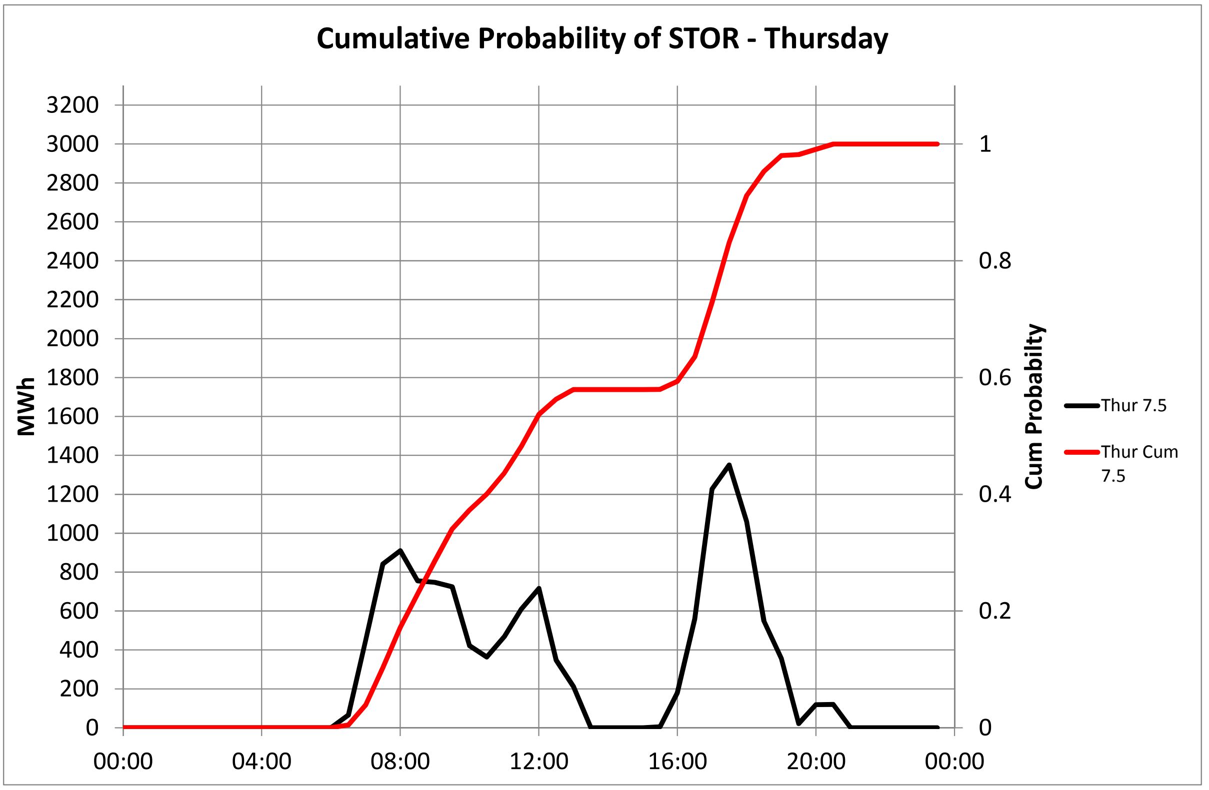


Figure 39 Calculation of cumulative probability of STOR for Thurdays season 7.5

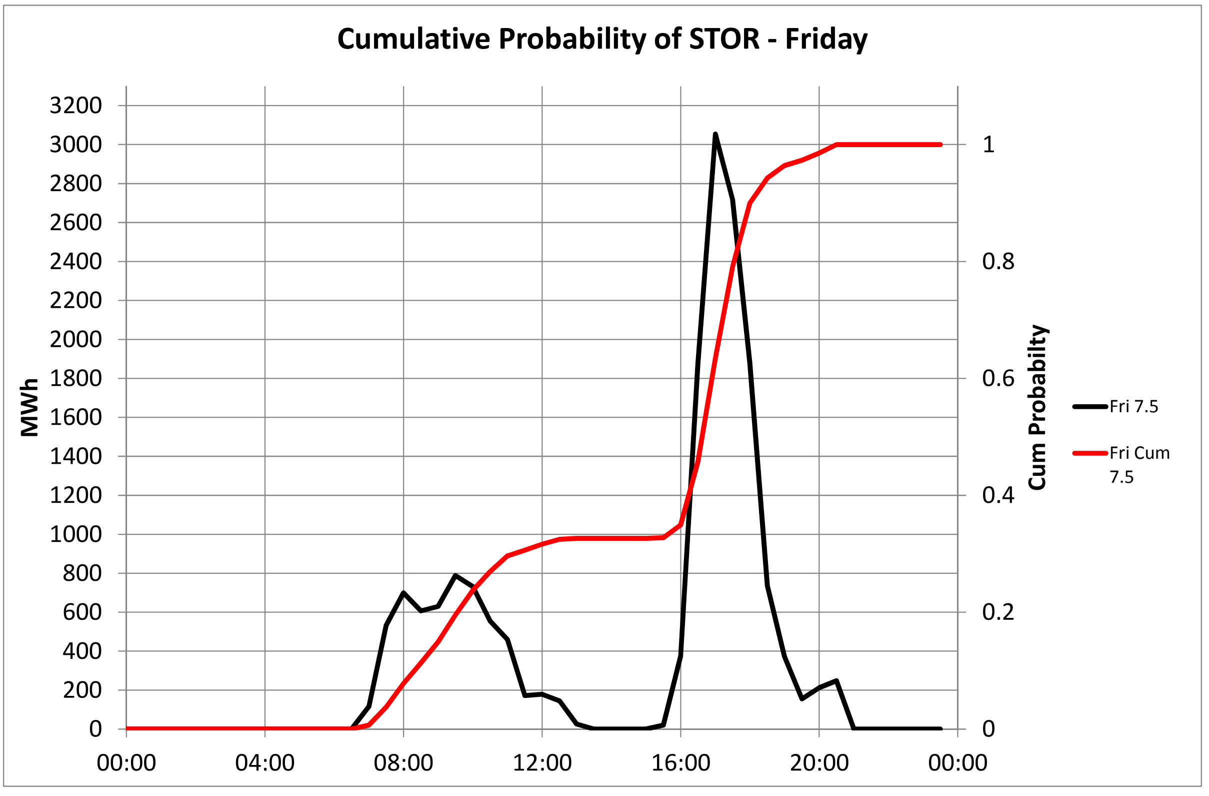


Figure 40 Calculation of cumulative probability of STOR for Fridays season 7.5

8.3. Modelling demand recovery following a period of demand reduction

It was noted in section 4.3.2, that certain sub-loads may experience demand recovery at the end of a period of significant demand reduction. This was seen for an HVAC system by Cobelo [34] and is presented in the same section. This applies to any demand which has inherent storage. For space heating and cooling applications the storage is in the thermal characteristics of the building. Other examples of sub-loads with storage are refrigerated warehouses and systems with batteries such as uninterruptible power supplies (UPS). Whilst the recovery for a single system may be relatively small the synchronisation of these (aggregated) recoveries could cause a significant peak in demand.

The results from Cobelo et al [34] show a 400 kW peak recovery above a baseline of about 700 kW immediately after the end of the demand reduction. However, Mathieu et al [35] noted a significant difference in three recovery peaks, including one with a negative recovery. It should be noted that they measure recovery an hour after the demand shed and this cannot be directly compared with the peak reported by Cobelo et al.

A search of the literature did not find comprehensive analysis of demand recovery peaks. Therefore a generalised model for demand recovery was developed. This model is also used for the work in later chapters. This relates the energy in the recovery to the energy unutilised due to the demand reduction. This model is specified by two parameters: the recovery factor; and the time duration of the recovery. This is explained below.

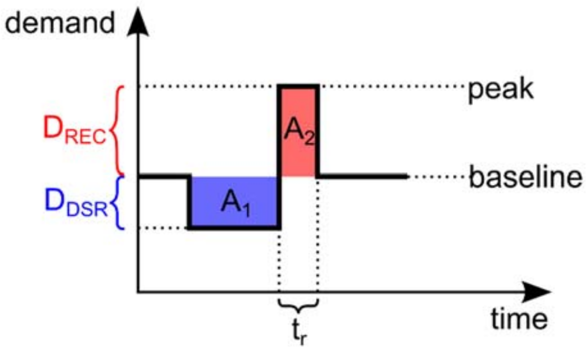


Figure 41 Model of demand recovery due to DSR

Figure 41 shows a demand reduction D_{DSR} due to DSR. The energy reduced during the demand reduction period is A_1, the area under the baseline demand. The demand recovery in the model is related to this reduction in energy by an demand recovery factor, F_{R}, so that

$$A_2 = A_1 \times F_{\mathrm{R}}$$

Therefore for a demand recovery factor of 1, all the unutilised energy during the demand reduction is recovered.

The recovery factor and the duration of the recovery, t_{R} (in hours), defines peak (above the baseline) of the recovery demand, D_{REC} (in kW):

$$D_{\mathrm{REC}} = \frac{A_2}{t_{\mathrm{R}}}$$

where D_{REC} is the demand recovery peak in kW and t_R is the time of the demand recovery, in hours.

To summarise, the demand recovery model is specified by two parameters:

- the recovery factor, F_{R} , and
- the duration in which the demand recovers, t_{R}.

8.4. Parameter space and values

This section defines the parameters used for the experiments that investigate the interaction between STOR provision and Triad. The Triad season coincides with STOR seasons 5 and 6. The dates for these seasons are shown in Table 23. The Triad dates in 2013/14 are given in Table 24 which also shows which STOR season they occurred in. For the year 2013/14 all the Triads occurred in STOR season 5.

Season	Date	Time of coincidence with Triad period
5	28-Oct-13 to 03-Feb-14	~ 3 months
6	03-Feb-14 to 01-Apr-14	~ 1 month

Table 23 Dates for STOR seasons 5 and 6 [76]

Date	Time	STOR season
Monday 25th November 2013	17:00 - 17:30	5
Thursday 30 January 2014	17:00 - 17:30	5
Friday 6 December 2014	17:00 - 17:30	5

Table 24 Triad dates in 2013/14

For this experiment the demand profile used is a constant value since the purpose is to investigate the interaction between the STOR provision and the Triad and the introduction of other varying parameters would add unrequired detail that could obfuscate the results. This value of demand used is 800 kW. It is assumed that all the energy shed during the DSR call is recovered after the call so the recovery factor is set to 1.

In order to establish a limit on the parameter space a maximum recovery peak is set. This is then used to calculate the minimum recovery time based on the recovery model described. . This is based on an assumption that the aggregated rating of all the sub-loads is approximately twice the baseline demand. In other words the maximum demand is limited to around $1600\ \text{kW}$, giving a maximum recovery peak of 800 kW. For a maximum STOR duration of 1.5 hours the energy reduction due to STOR would be $150\ \text{kWh}$. Applying a recovery peak of $800\ \text{kW}$ gives a duration of recovery of $\frac{180\ \text{kWh}}{800\ \text{kW}} = 0.1875\ \text{hours} = 11.25\ \text{minutes}$. Rounding down to a minimum recovery period of 10 minutes then gives a maximum recovery above baseline of $882\ \text{kW}$ which is approximately twice the baseline demand.

The Triad half hour is modelled to a time period of 1 minute, which gives a maximum error of ± 0.5 minutes. Therefore, for a constant demand of $800\ \text{kW}$ the accuracy of the average demand over the half hour is $\frac{\pm 0.5}{30} \times 800 = \pm 13\ \text{kW}$

The number of calls per year, N_{Total}, was set at 60. This is based on figures from Sustainability First that suggest the number of calls to be 20 – 80 calls of one hour per year [57] and the Thinking Grids website that gives a figure of around 70 calls per year [77].

The number of STOR window hours offered is set to 260. This is an average of one hour for every working day. The value affects the availability income from STOR.

The income from STOR assumes an availability price of 4.94 (£/MW)/h and a utilization price of 183.76 (£/MWh) which are average values when long term contracts have been removed [76].

The assumptions for utilisation and availability prices and Triad cost are given in Table 25. These are the average values after long term contracts have been removed, for the STOR year 2013/14. The table also shows that the number of assumed STOR calls in a year is 60. The actual number of calls is subject to a binomial distribution as described in section 8.2.1.

	Value	Source
Triad price	22.346537 £/kW	2013/14 taken from [78]
Utility	183.76 £/MWh	average values when long term contracts have been removed [76]
Availability price for STOR	4.94 (£/MWh)/h	
kWh price	6.849 p/kWh	
STOR calls per year	60	Estimate based on [57] [77]

Table 25 Data assumptions for the models

8.5. Method

A MATLAB script was written to import data, create objects and run a Monte Carlo simulation for 10,000 iterations for each combination of the STOR durations and recovery times defined in the parameter set. An overview of the process is shown in Figure 42. The imported data includes Triad dates, bank holiday dates, DUoS times and charges, STOR seasons and window times, STOR cumulative probability data and STOR price data. This is used to create objects which model the timing of STOR calls, triads, a STOR provider and the electricity bill cost of that STOR provider.

The detail of 'Run Monte Carlo simulation' is shown in Figure 43. For each iteration of the Monte Carlo a *powerAgent* is created which models the STOR provider. A *storSchedulerFixedDur* object is created to generate the STOR call times and dates with a fixed duration. For each simulated day this determines whether STOR was called. If it was called, then DSR is called on the STOR provider (*powerAgent*). When all the days have been simulated the cost of the bill is calculated and the objects and results are recorded. Then the next Monte Carlo iteration is simulated.

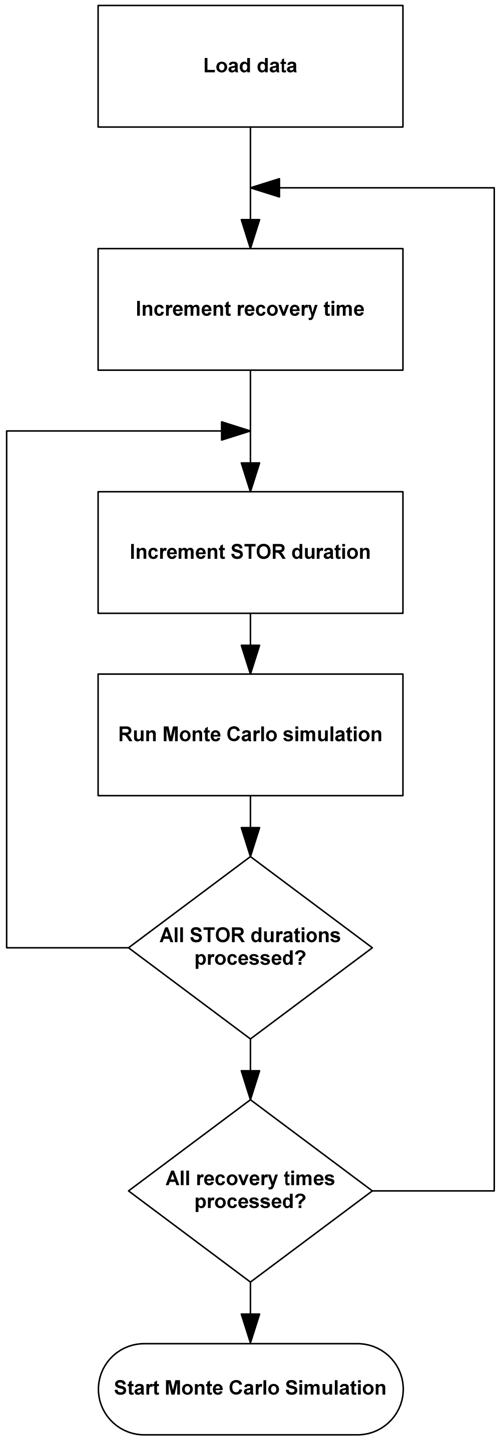


Figure 42 Overview of the script to simulate STOR and Triad coincidence

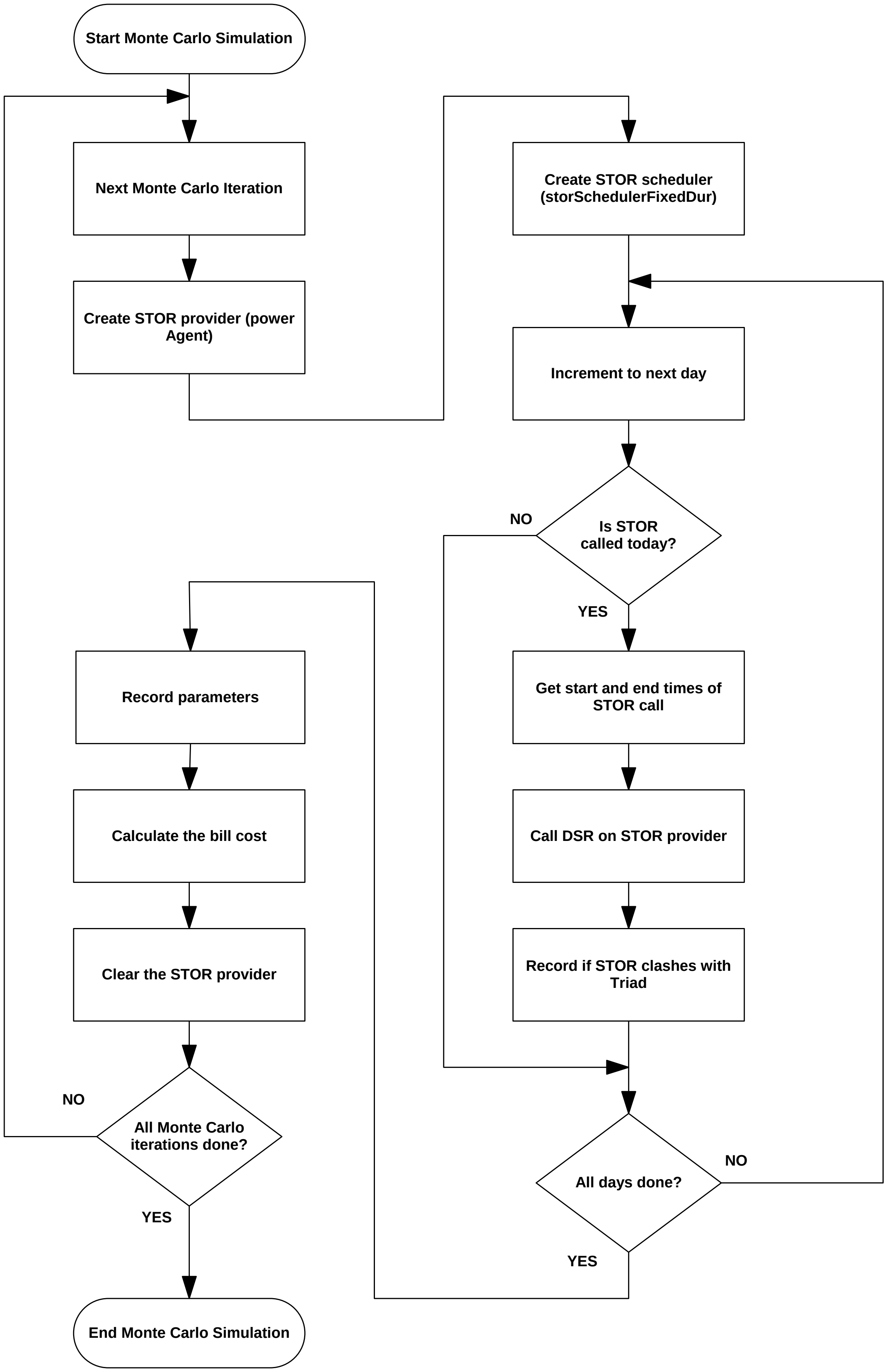


Figure 43 Detail of the process which runs a Monte Carlo simulation for STOR and Triad coincidence

8.6. Results for the probability that Triad demand is increased or decreased

In general the STOR call may decrease, increase or have no affect on the Triad demand. This section evaluates the possibilities of increased or decreased Triad demand. Figure 44 shows the probability that the demand during Triads will be decreased by more than 1 kW. The 1 kW threshold is introduced to exclude results that represent 'almost no change'. A decreased Triad would give an additional financial benefit to providing a STOR service due to the reduced costs. The probability of this happening is between 1 – 4% for the STOR durations and recovery times considered. Figure 45 shows the probability of increased Triad demand due to STOR provision which ranges form 0 to 1.6 %. The probability of no change in Triad demand is simply:

$$P_0 = 100\% - P_{INC}\,(\%) - P_{DEC}\,(\%)$$

For the whole parameter set the probability of no change to Triad demand is by far the greatest, and ranges from 95.75 to 97.75 %. When there is no demand recovery there is no chance of an increase in the Triad demand.

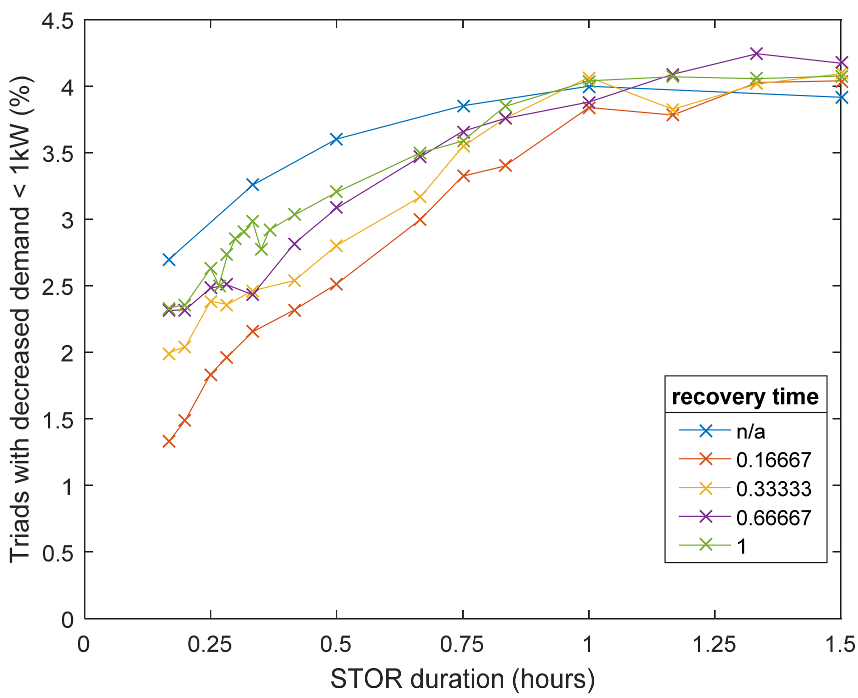


Figure 44 Probability of decreased Triad demand due to STOR

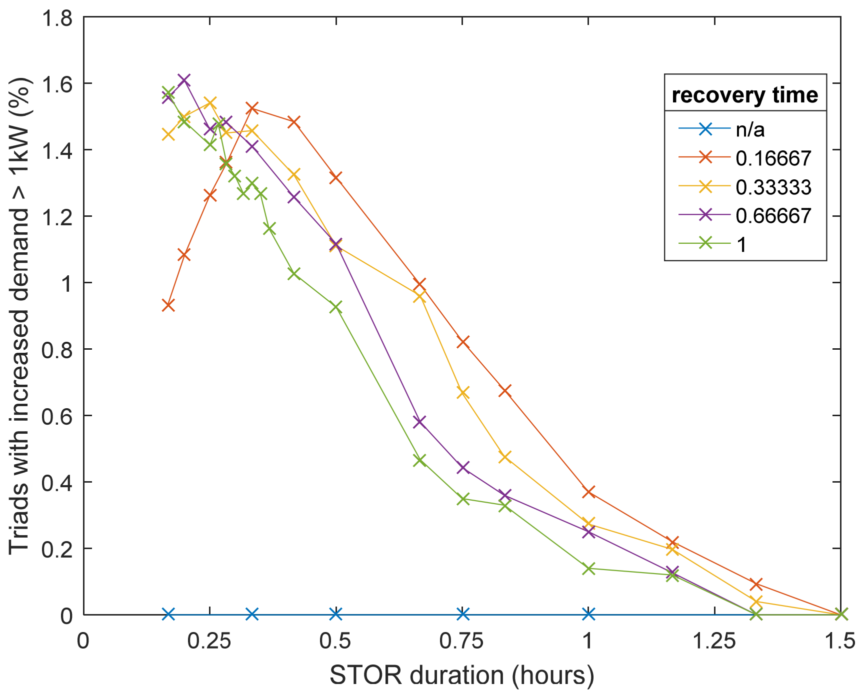


Figure 45 Probability of increased Triad demand due to STOR

8.6.1. Discussion of results for the probability of increased or decreased Triad demand

8.6.1.1. STOR calls greater than 1.5 hours

Figure 46 shows demand reduction in response to a STOR call which starts at 16:00 and lasts for 1.5 hours. The second STOR window (for Season 5) starts at 16:00, therefore this is the earliest time at which the demand reduction would occur. In the case for 1.5 hour STOR duration the demand recovery starts just at the end of the Triad period and so would never have an impact on the Triad demand. This is true for any STOR call in the second STOR window with a duration of 1.5 hours or longer no matter when the call is made.

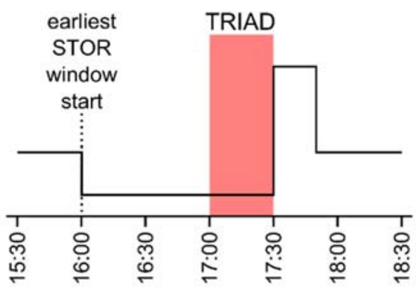


Figure 46 1.5 hour STOR duration

8.6.1.2. Explanation of why the 10 minute STOR call shows less probability of increased Triad demand than the 20 minute STOR call

It was seen in Figure 45 that the probability of increased Triad demand for 10 minute recovery shows a peak of about 1.6 for a STOR duration between 0.3 and 0.4 hours. The reason for this is explained in the following.

Figure 47 shows the three cases of STOR call and demand recovery for a 10 minute and a 20 minute STOR call, both with 10 minute recovery. In both cases the recovery factor is 1. For these STOR durations the probability of increased demand is ~0.9 and 1.5 respectively (see Figure 45).

The following refers to the 10 minute STOR duration (Figure 47a). Since the demand recovery factor is 1 the energy reduction during STOR is equal to the energy in the recovery and they are equal area. Case 1 shows the earliest time at which STOR could start that would cause the average Triad demand to increase, this is just after 16:40. Case 2 shows the latest time that STOR could start and cause an increase in average Triad demand which is just before 17:00. The curve in case 3 shows a STOR call at 17:00, here the energy in the recovery phase is completely balanced out by the energy in the Triad reduction. This gives an average Triad demand which is equal to the baseline demand. Therefore the Triad demand does not increase in case 3. For STOR calls any later than this the average Triad demand will be equal to or less than the baseline demand. The total time range for which a STOR call will cause an increased Triad is almost 20 minutes as indicated in red below the time axis.

Figure 47b shows three cases of STOR call times for a STOR duration of 20 minutes. Since the STOR call is longer and the energy reduction during the STOR period is equal to the energy in the recovery, the recovery peak is higher. Case 4 shows the earliest STOR call which causes the average Triad demand to increase, this comes at just after 16:30. Case 5 shows the latest time at which a STOR call would cause an average increase in Triad demand. Again this is at just before 17:00. Lastly case 6 shows a STOR call starting at 17:00 where the energy reduction of STOR completely balances the energy in the recovery resulting in an average Triad demand which is equal to the baseline. The total time range for which a STOR call will cause an increased Triad is almost 30 minutes as indicated in red below the time axis.

Since the STOR call in Figure 47b is longer there is a larger range of STOR call start times where the recovery peak is not balanced out by the STOR reduction. Therefore the time of increased Triad demand is higher for a 20 minute STOR call. This is why the probability of increased Triad is higher for a 20 minute STOR call (~1.5) than for a 10 minute STOR call (~0.9).

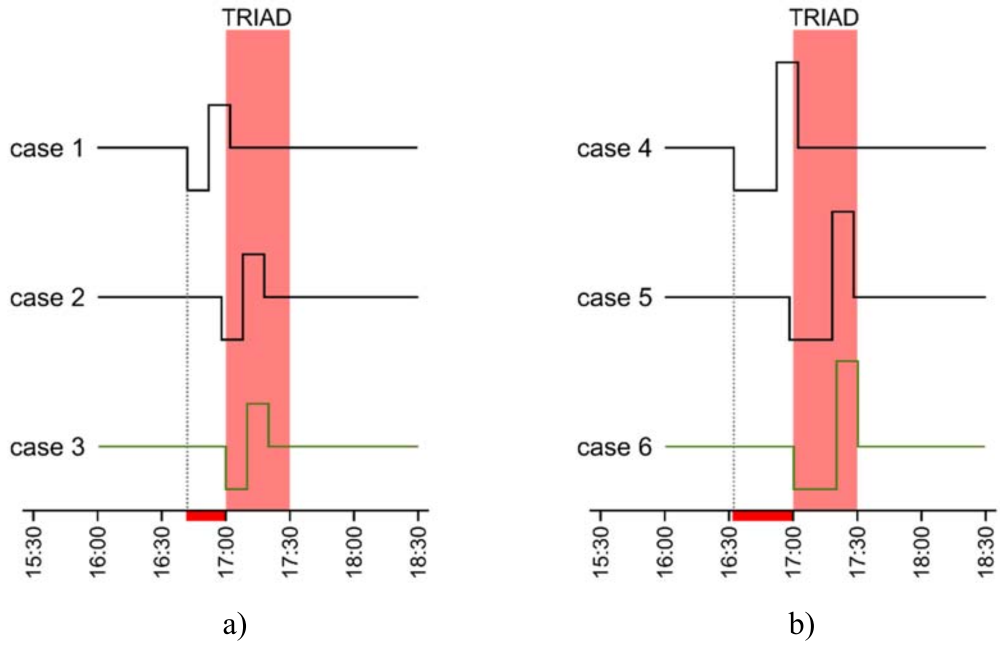


Figure 47 Increased Triads for (a) 10 minute and (b) 20 minute STOR duration

Referring to Figure 48, the blue areas show the energy reduction and increase above the baseline demand. In general to determine whether a Triad is increased or decreased due to STOR recovery it is only necessary to know whether the energy reduction (due to STOR) within the Triad period is greater or less than the energy increase (due to recovery) within the Triad period.

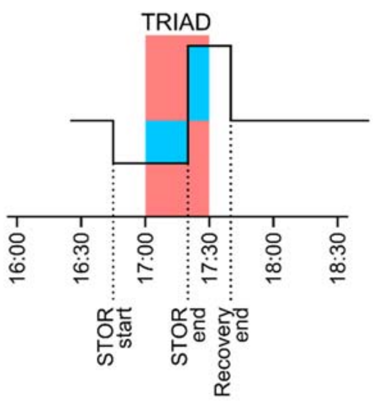


Figure 48 Comparing energy increase and with energy decrease during Triad period

Equations for calculating the energy reduction due to STOR and the energy increase due to recovery are given in the following. The recovery peak above baseline, D^{+}_{PEAK} , is given by:

$$D^{+}_{\mathrm{PEAK}} = \frac{R^{-}_{\mathrm{STOR}} \times t_{\mathrm{STOR}} \times \mathrm{F_R}}{t_{\mathrm{R}}}$$

where R^{-}_{STOR} is the STOR kW reduction below baseline, t_{STOR} is the STOR duration, $\mathrm{F_R}$ is the recovery factor, and t_R is the recovery time. The STOR energy reduction within Triad, Q^{-}_{STOR} in kWh (shown as a blue shaded area on the left side in Figure 48), is given by:

$$Q^{-}_{\mathrm{STOR}} = \begin{cases} (t_{STOREND} - t_{TRIADSTART}) \times R^{-}_{\mathrm{STOR}} \text{ for } (t_{STOREND} - t_{TRIADSTART}) > 0 \\ 0 \text{ for } (t_{STOREND} - t_{TRIADSTART}) \leq 0 \end{cases}$$

where $t_{STOREND}$ is the end time of the STOR call, and $t_{TRIADSTART}$ is the start time of the Triad. The recovery energy within Triad, Q^{+}_{REC} in (kWh) is given by:

$$\text{Recovery energy within Triad, } Q^{+}_{\mathrm{REC}}\ (\mathrm{kWh}) = (t_{TRIADEND} - t_{STOREND}) \times D^{+}_{\mathrm{PEAK}} \tag{1}$$

If the recovery ends before the end of the Triad period the recovery energy within the Triad is simply $D^{+}_{PEAK} \times t_{REC}$. Note that this is the same as substituting the end time of the recovery $t_{STOREND} + t_{REC}$ with $t_{TRIADEND}$ in Equation **(1)**.

For STOR calls of 1.5 hours duration or longer any demand recovery will occur after the Triad period as illustrated in Figure 46 and there is no possibility of increased Triad demand.

8.7. Results for the extent of increase or decrease in Triad demand

The previous results section looked at the probability that Triad demand would be increased or decreased. This section investigates the extent, in terms of kW, to which they might be increased or decreased.

8.7.1. Extent of increase in Triad

For increased Triad this is calculated by first summing the total kW increase in Triad demand over the whole Monte Carlo simulation and dividing by the number of Monte

Carlo iterations, n_{MC}, (which is 10,000) in order to give a mean increase in Triads, $\overline{\Delta D}_{\mathrm{TRIADTOT}}$.:

$$\overline{\Delta D}_{\mathrm{TRIADINCTOT}} = \frac{\sum_{i=1}^{10,000}(D_{\mathrm{INCTRIAD}} - D_{\mathrm{TRIADNOSTOR}})}{n_{\mathrm{MC}}}$$

where $D_{\mathrm{INCTRIAD}} = \begin{cases} D_{\mathrm{TRIAD}}, & if\ D_{\mathrm{TRIAD}} > D_{\mathrm{TRIADNOSTOR}} \\ 0 \end{cases}$ This value is then divided by the number of Triads in a year (i.e. three) to give the average increase in Triad kW in the long term :

$$\overline{\Delta D}_{\mathrm{TRIAD}} = \frac{\overline{\Delta D}_{\mathrm{TRIADTOT}}}{N_{\mathrm{TRIADS}}}$$

This is then expressed as a percentage of the Triad demand without STOR provision. It is therefore a relative increase in Triad demand:

$$\overline{\Delta D}_{\mathrm{TRIADREL}} = \frac{\overline{\Delta D}_{\mathrm{TRIADTOT}}}{N_{\mathrm{TRIADS}}} \times 100$$

Figure 49 shows the relative increase of demand with STOR duration. As stated earlier it is impossible for the demand recovery to occur during the Triad for STOR durations greater than 1.5 hours and so this has zero probability. It can be seen that for shorter recovery durations the change in Triad demand is generally higher, except for 10 minute and to a lesser degree 20 minute recovery periods at short STOR durations. This reflects the results for the probability of increased Triad shown in Figure 45.

8.7.1. Extent of increase in Triad

For decreased Triad the extent, in kW, of the decrease is calculated in a similar way as for the extent of increased Triad to give a relative decrease in Triad demand, as shown in Figure 50. Note that the scale is different to that of Figure 49.

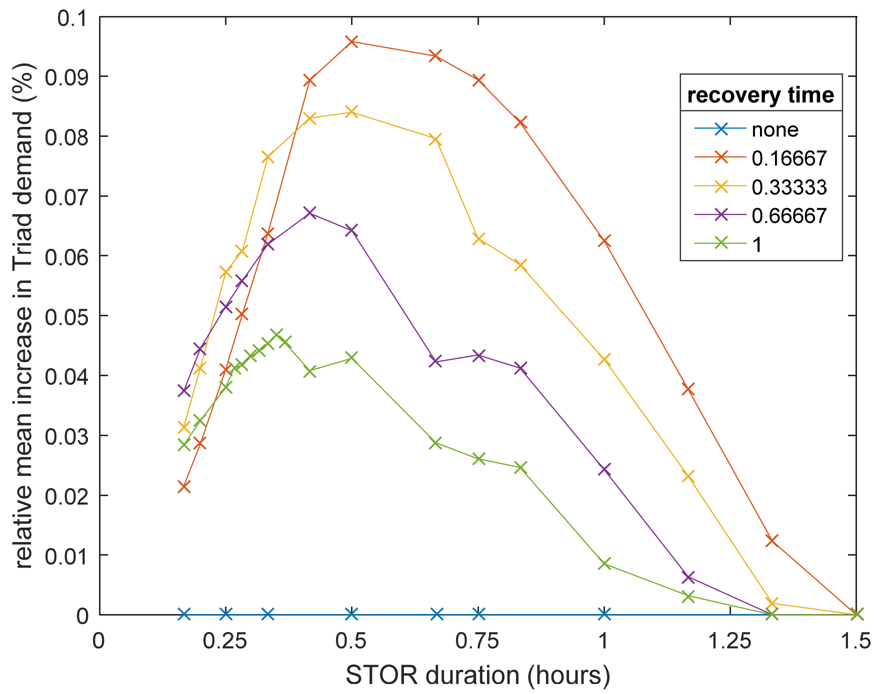


Figure 49 The relative increase in Triad demand

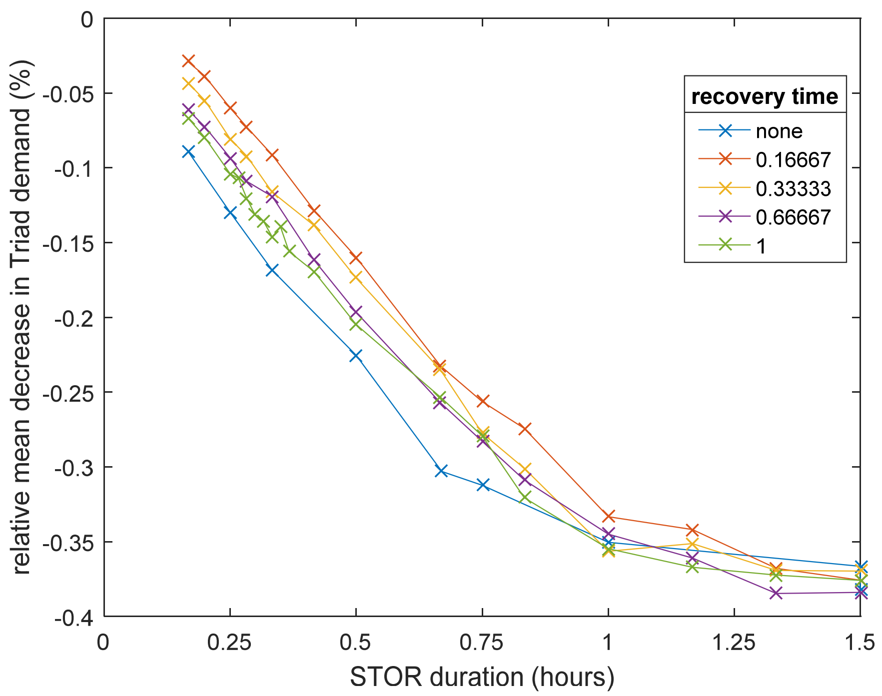


Figure 50 The relative decrease in Triad demand

8.8. The total cost benefit of providing STOR

The previous results section considered the extent to which Triad might be increased or decreased. This would have implications on the bill cost. This section also considers the income from STOR in order to give the probability of cost benefit for different STOR durations and recovery times. The Monte Carlo simulation modelled 120 days to consider only the dates which include the Triad season. Therefore the cost benefit applies to taking part in STOR during the Triad season only.

The total calculated bill cost for a customer who does not participate in STOR at all is £220,050 based on the values in Table 25 and running the model without STOR. The cost benefit is defined as:

$$B_{TOT}\ (£) = C_{NOSTOR} - C_{STOR} + S_{inc}$$

where C_{STOR} is the bill cost for a STOR provider, C_{NOSTOR} is the bill cost for a non-STOR provider, and S_{inc} is the income gained from STOR provision. If the cost of the bill for STOR provision is the same as the cost of the bill for no STOR provision (i.e. no Triad demand was changed) then the benefit is simply S_{inc} , the income from providing STOR. However, if the Triad demand is decreased due to providing STOR then the bill cost C_{STOR} will be smaller than C_{NOSTOR} and the benefit B_{TOT} (£) will be larger. The relative cost benefit percentage, B_{REL} is defined as:

$$B_{REL}(\%) = 100 \times \frac{B_{TOT}}{C_{NOSTOR}}$$

Substituting the equation for B_{TOT} earlier the equation has the same form as reported in [74]:

$$B_{REL}(\%) = 100 \times \left(1 - \frac{S_{inc} - C_{STOR}}{C_{NOSTOR}}\right) \tag{2}$$

The mean cost benefit for providing STOR is shown in Figure 51. In general it increases with STOR duration. The factors which contribute to increased income are: increased STOR utility income and potentially decreased Triad charges. The mean cost benefit is seen to range from 0.1 to just above 0.4 for the STOR durations considered. However, National Grid data [76] shows that half of the STOR calls are longer than 1.5 hours so there is potential for the benefit to be higher.

The mean cost benefit for providers without demand recovery is larger because they use less energy overall. In other words there has been an efficiency saving for that case.

However if this was provided by a generator there would be increased total costs due to fuel and maintenance.

Figure 52 shows the cost benefit for the 99th percentile. The cost benefit for these providers ranges from about 0.2 to 0.8 for the STOR durations considered but shows diminishing returns at longer STOR durations.

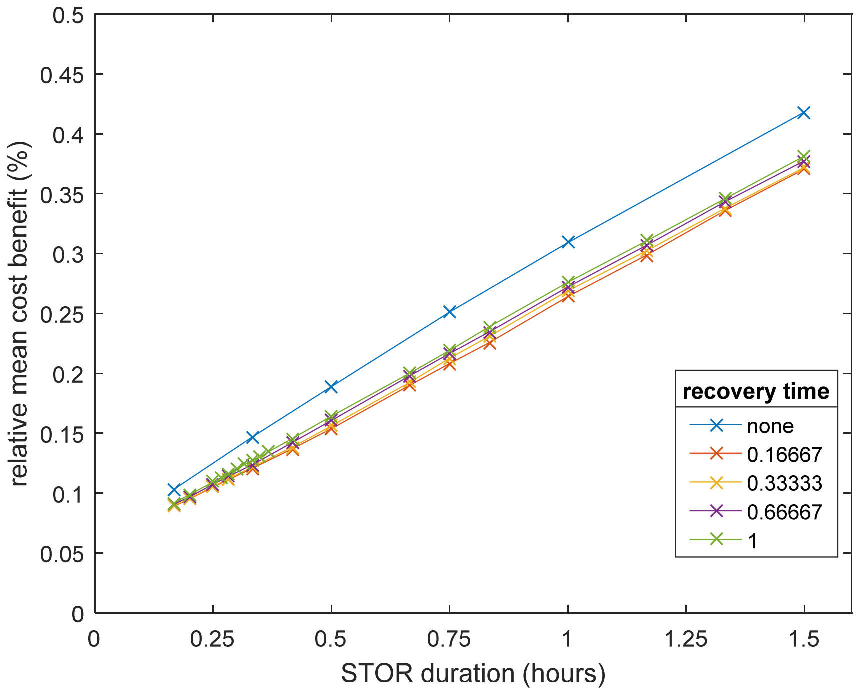


Figure 51 Relative mean cost benefit

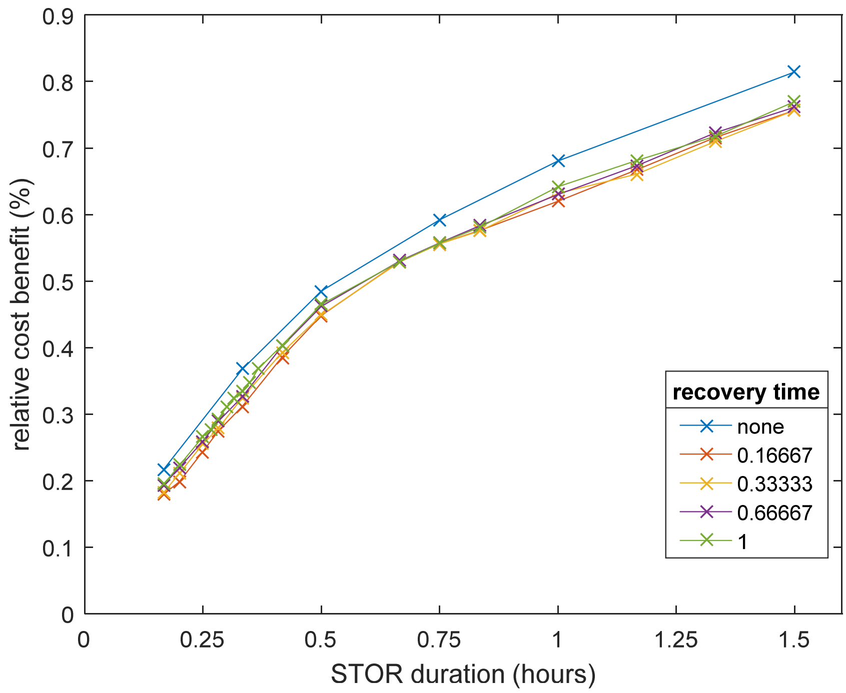


Figure 52 Cost benefit for the 99th percentile

Figure 53 show the cost benefit for the 1st percentile. Here the cost benefit is negative between 12 and 50 minutes for recovery times of 10 and 20 minutes and between 12 and 34 minutes for a recovery time of 40 minutes. This means that the increased Triad bill was greater than the STOR income at these times and recovery durations.

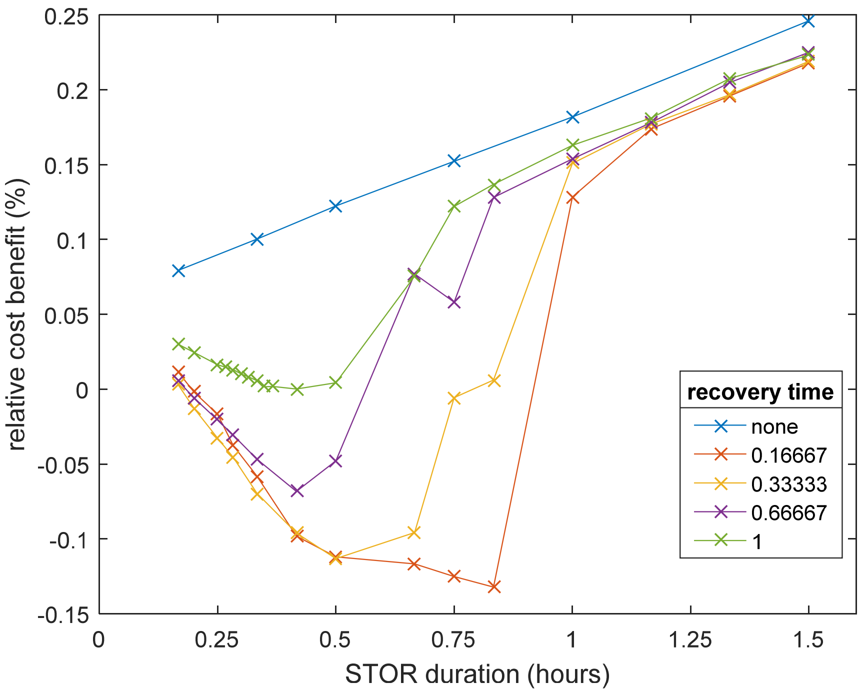


Figure 53 Cost benefit for the 1st percentile

8.9. Probability spread of cost benefit

The previous section looked at the cost benefit of providing STOR by demand reduction with different load recovery characteristics. It was seen that the relative cost benefit curve shapes for the 1st percentile of cases were very different to those of the mean. The results for the 99th percentile also differ from the mean but to a lesser degree. This section presents histograms of the cost benefit for the 10,000 Monte Carlo runs.

Figures 54, 55 and Figure 56 show histograms of the probability that the relative cost benefit will be for STOR durations of 30 minutes, 50 minutes and 15 hours all with a demand recovery of 10 minutes. The peak probability that a 30 minute STOR with 10 minute demand recovery is less than 0.2. For increased STOR durations of 50 minutes and 1.5 hours with the same recovery the peak probabilities increase. Note also that the spread of probabilities increases and that a minor peak is seen in Figures 55 and Figure 56 at 0.54 and 0.68. The major peaks on these histograms are at 0.2 and 0.34 respectively, giving a difference in relative cost benefits of 0.34 % between the peaks in both cases.

These are likely due to STOR calls totally overlapping a Triad period. The reason for this is explained below.

The mean Triad demand if no STOR overlaps any Triad period is 800 kW. If a STOR call totally overlaps one Triad period the demand for that Triad period is reduced to 700 kW which gives the calculated Triad demand as:

$$\frac{800 + 800 + 700}{3} = 766.7 \text{ kW}$$

Which is a reduction of 33.3 kW. Due to the cost of Triad demand, this reduction represents a saving of

$$33.3 \times 22.35 = £744$$

In Equation **(2)** the cost benefit was defined as

$$B_{REL}(\%) = 100 \times \left(1 - \frac{S_{inc} - C_{STOR}}{C_{NOSTOR}}\right)$$

To calculate the additional benefit from a reduction of 100 kW in one Triad subtract the £744 from the total cost benefit to give:

$$B'_{REL}(\%) = 100 \times \left(1 - \frac{S_{inc} - (C_{STOR} + £744)}{C_{NOSTOR}}\right)$$

$$B'_{REL}(\%) = 100 \times \left(1 - \frac{S_{inc} - C_{STOR}}{C_{NOSTOR}} - \frac{-£744}{C_{NOSTOR}}\right)$$

$$B'_{REL}(\%) = B_{REL}(\%) \times \left(\frac{£744}{C_{NOSTOR}}\right)$$

Inserting the value the bill cost without STOR, C_{NOSTOR} , which is £220,050:

$$B'_{REL}(\%) = B_{REL}(\%) + 100\left(\frac{£744}{£220,050}\right)$$

$$B'_{REL}(\%) = B_{REL}(\%) + 0.34\%$$

This value of 0.34% corresponds with the distance between the peak and the minor peak, indicating that the second peak is due to a Triad being reduced across the full half hour by a STOR call.

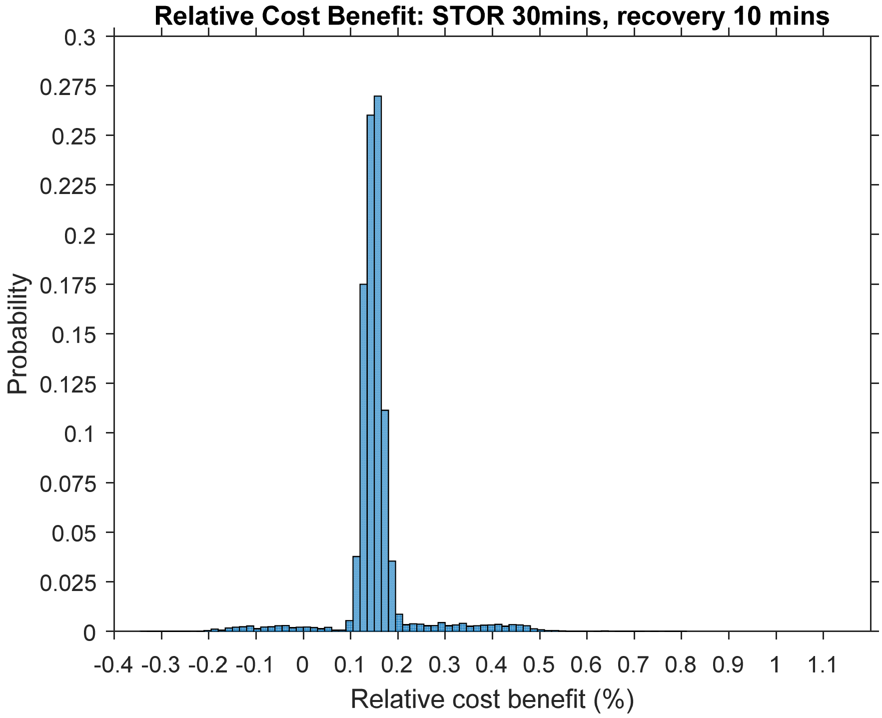


Figure 54 Relative cost benefit for STOR duration 30 minutes and demand recovery of 10 minutes

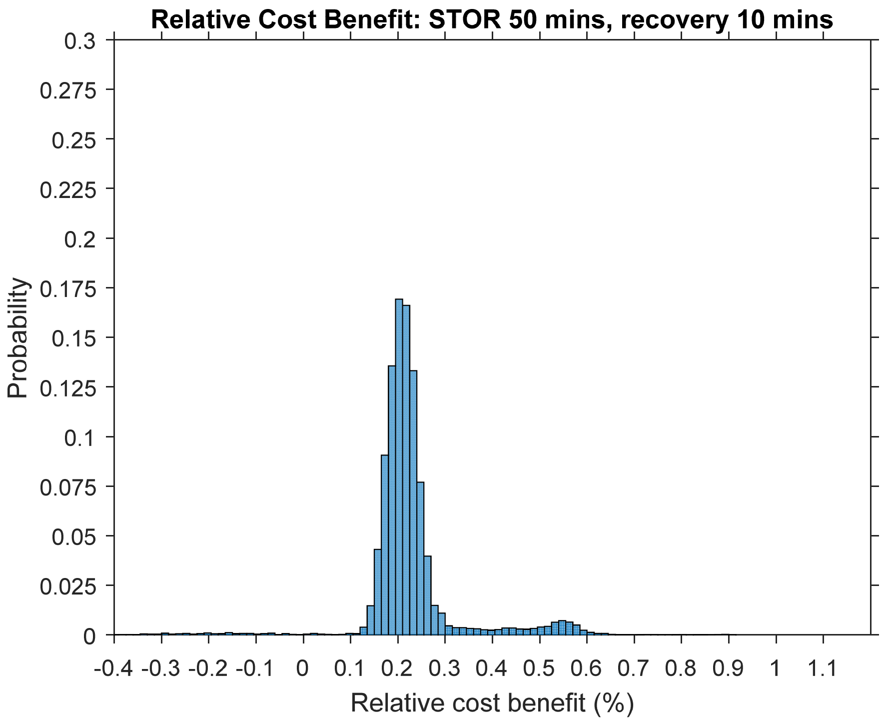


Figure 55 Relative cost benefit for STOR duration 50 minutes and demand recovery of 10 minutes

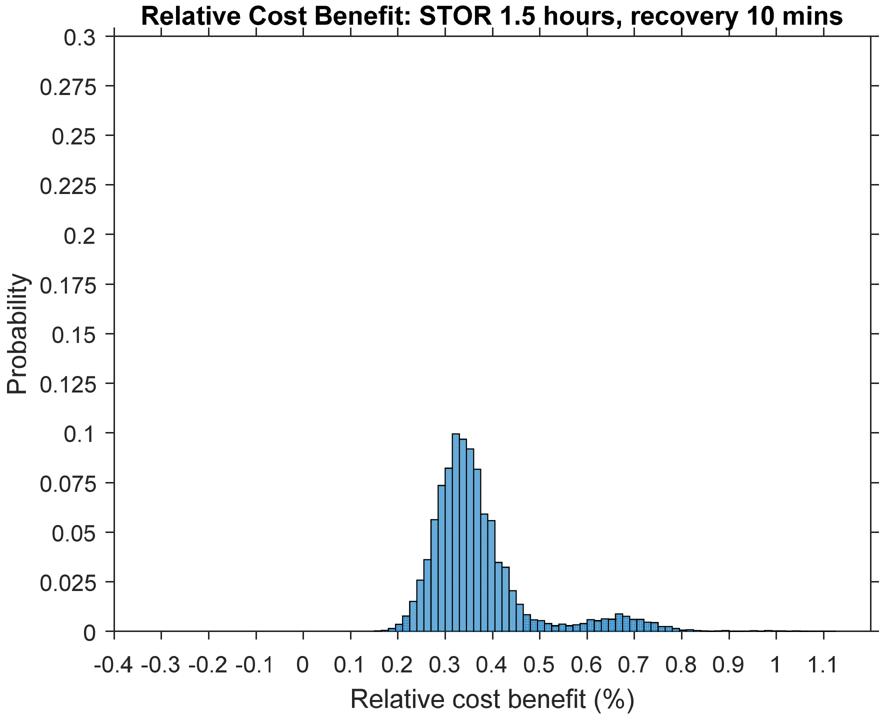


Figure 56 Relative cost benefit for STOR duration 1.5 hours and demand recovery of 10 minutes

8.10. Probability of increased and decreased total cost benefit of providing STOR by demand reduction

An increase or decrease in Triad cost will have an impact on the overall financial benefit of providing STOR. This section looks at the probability that the relative cost benefit will be less than zero, neutral (between 0 and 0.05 %) and positive (greater than 0.05 %). It was seen in Figure 53 that the cost benefit for the 1st percentile was sometimes negative at for recovery periods greater than 40 minutes. Figure 57 shows the percentage of negative cost benefit for the whole set of Monte Carlo runs, n_{MC} , (which is 10,000) compared to Figure 53 which showed only the 1st percentile and for the total cost benefit not just the negative cost benefit.

$$\text{negative cost benefit (\%)} = \frac{n_{\mathrm{NEGBEN}}}{n_{\mathrm{MC}}}$$

where n_{NEGBEN} is the number of cases where $B_{REL} < 0$ and B_{REL} is defined in Equation **(2).**

Figures 58 and 59 show the probability of neutral cost benefit and positive cost benefit respectively:

$$\text{neutral cost benefit (\%)} = \frac{n_{\text{NEUTRAL}}}{n_{\text{MC}}}$$

and

$$\text{positive cost benefit (\%)} = \frac{n_{\text{POSITIVE}}}{n_{\text{MC}}}$$

where n_{NEUTRAL} is the number of cases where $0 \leq B_{REL} \leq 0.05$ and n_{POSITIVE} is the number of cases where $B_{REL} > 0.05$.

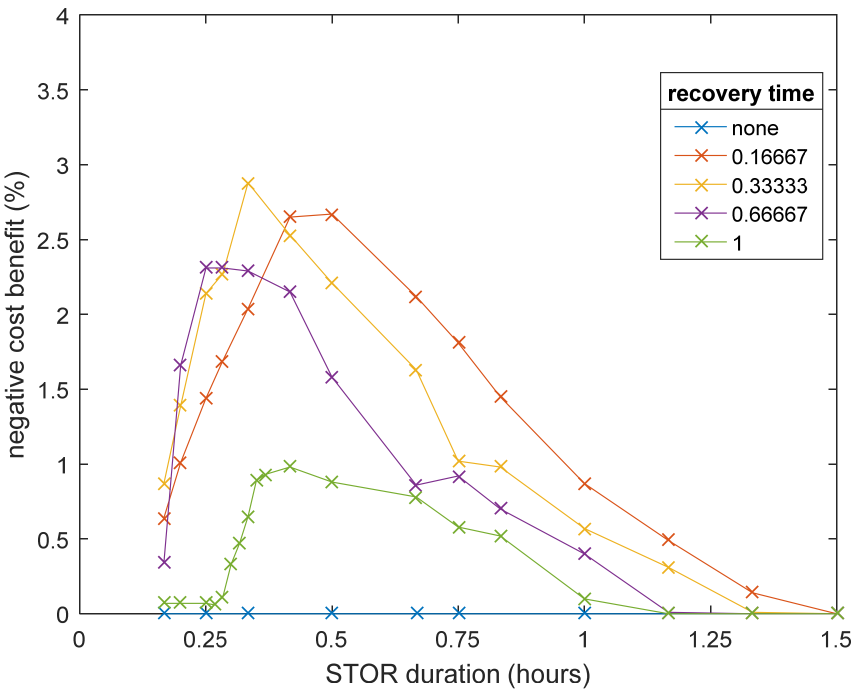


Figure 57 Probability of negative cost benefit

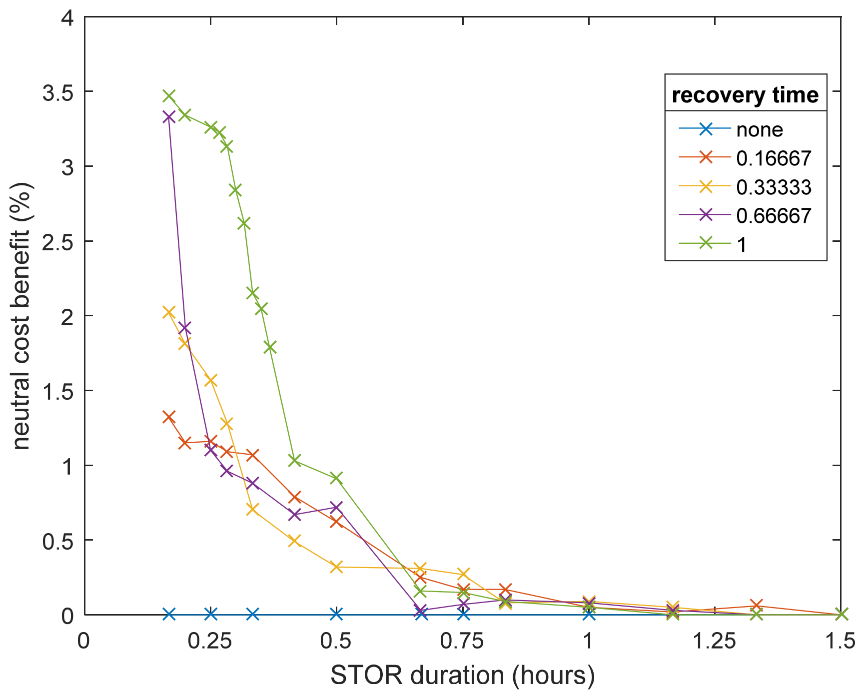


Figure 58 Probability of neutral cost benefit

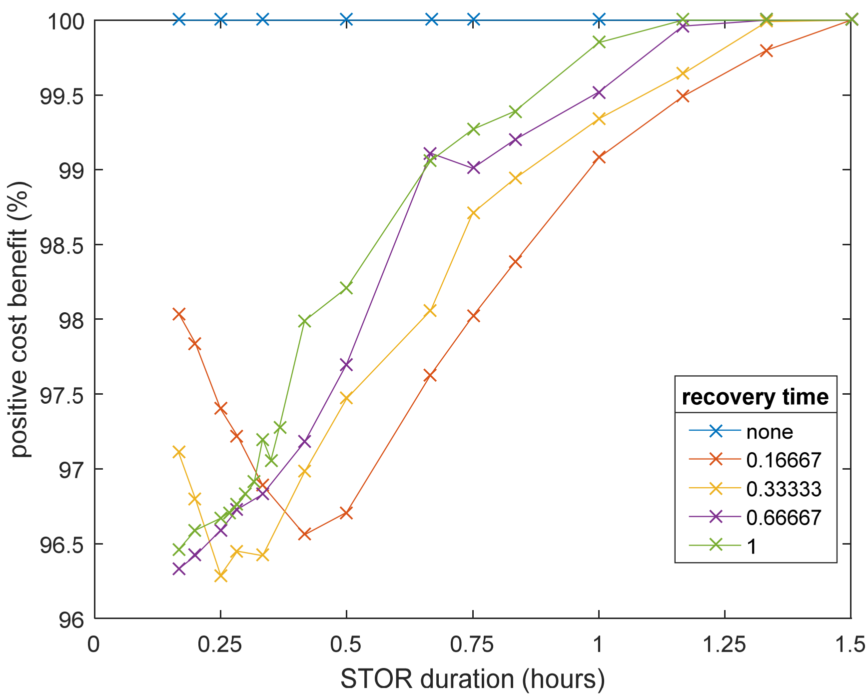


Figure 59 Probability of postive cost benefit

It can be seen that there is at least a 96 % chance of the cost benefit being positive. For STOR durations less than 20 minutes the probability of neutral cost benefit increases up to 3.5 % for longer recovery times. The probability of negative cost benefit peaks between 2.5 to 3 % for STOR durations between 15 - 30 minutes.

8.11. Model and results limitations

The modelling in this work assumed a fixed demand in order to highlight the potential interference of STOR provisions with Triad demand. The results are based on data from 2013/14.

Table 26 shows a list of parameter used for in the modelling and their limitations or assumptions.

Parameter	**Data**	**Assumption or Limitation**
Optional Windows		Not included in modelling
Triad times		Actual Triads in year 2013/14
Demand profile		Constant value used so as not to obfuscate the results
Maximum demand	1,600kW	Assumed value
Number of expected STOR calls per year	60	Based on [57] and [77]
STOR windows offered	260	An average of one for every working day
STOR availability price	4.94 (£/MW)/	2013/14 value
STOR utilization price	183.76 (£/MWh)	2013/14 value (average value after long term contracts have been removed [76]).

Table 26 Summary of parameter values and limitations

8.12. Summary

The provision of STOR by demand reduction is most likely to have no effect on the Triad demand, this has a probability of more than 95.75 %. However the probability of decreased Triad demand is up to 4 % and the probability of increased Triad demand is up to 1.6%. The probability of increased Triad demand is greater with decreasing STOR duration in general. However, for STOR durations less than 0.3 hours and recovery durations of 10 minutes the probability reduces compared to the value at 0.3 hours STOR duration.

If the Triad demand increases, the expectation value for Triad demand kW, relative to the Triad demand without STOR provision, ranges from 0 % to 0.1 % of the Triad demand kW, for the parameters considered. As shown in Figure 49 this depends on the recovery time of the demand as well as the STOR duration. The relative increase is larger for shorter recovery durations. The values peak for STOR durations between about 0.3 to 0.75 hours duration. The peak is wider and falls off more steeply at shorter recovery times.

If the Triad demand decreases the expectation value relative to the Triad kW, without STOR provision, ranges from almost zero to -0.4 % (i.e. a decrease of 0.4%), see Figure 50. The magnitude of the decrease is larger for longer STOR durations.

In order to give either minimally increased or maximally reduced Triad demand the optimal situation is to have longer STOR durations and shorter recovery times, since the results would then be at the right hand side of the either the graph shown in Figure 49 or the right hand side of the graph shown in Figure 50. For STOR durations longer than 1.5 hours there is no chance of increased Triad demand.

The graph of mean relative cost benefit (Figure 51) shows the gains from energy efficiency for the case with no demand recovery. The curve for no recovery has a significantly greater cost benefit compared to the curves that include recovery. Since the recovery is a (time-shifted) energy demand, the absence of recovery represents an energy efficiency saving. For the first percentile of cases (see Figure 53) the cost benefit may be negative in some cases which means that the income gained from STOR was less than the increased Triad charges.

Histograms of the relative cost benefit of STOR provision show increased cost benefit probability with increasing STOR duration and also the spread of the probability peak becomes wider. A second peak is more apparent at long STOR durations. This minor peak corresponds to a Triad period being totally contained by the STOR period. Therefore this is higher chance of the Triad demand being reduced across the whole Triad period when the STOR duration is longer.

It should be noted that these results apply to 2013/14 data. STOR prices are decreasing and Triad charges are increasing, so where there is increased Triad demand due to STOR coincidence this will likely have a greater cost to the STOR provider in future.

In order to avoid demand recovery altogether a Diesel generator could be used to provide STOR. Although this would have an impact on carbon emissions there is a justification for the use of Diesel generators for balancing services. DECC [79] note that if Diesel back-up generation were not used for STOR then closed-cycle gas turbines (CCGTs) would have to be part loaded in order to provide the flexibility currently provided by Diesel generators. Part loading of the CCGTs has an impact on their efficiency. Quoting 2015 figures from National Grid they state that the CO_2 emissions from providing STOR with CCGTs is estimated at 683,213 tonnes per annum compared to an estimated 170,237 tonnes per annum from the current (2015) mix of STOR providers. However, they also note that regional regulations may seek to curb the use of standby generation for DSR due to concerns about environmental emissions. For example in the City of London the guidance is that “Standby generators in the City should not be used to feed electricity into the utility grid. They should be used in emergencies only”.

Table 27 shows the utilisation and calculated CO_2 emissions by fuel type from different STOR providers using data from 2014/15. The CO_2 emissions data are approximately calculated [80]. It can be seen that by far the majority came from open cycle and closed cycle gas turbines (OCGTs and CCGTs). Almost 6 % came from Diesel engines whilst less than 0.1 % was by demand reduction.

Primary Fuel Type	MWH Utilisation	MWH Percent of total	CO_2 tonnes	CO_2 Percent of total
Load Reduction	203	0.09%	0	0.00%
Hydro	1,916	0.83%	0	0.00%
Bio-Diesel	28	0.01%	0	0.00%
Biomass	2,302	0.99%	110	0.08%
CHP	8,697	3.75%	2,479	1.74%
Diesel	13,835	5.97%	10,168	7.14%
Gas Reciprocating Engine	27,849	12.02%	16,849	11.83%
CCGT	57,557	24.85%	23,138	16.25%
Pump storage	42,319	18.27%	29,877	20.98%
OCGT	76,909	33.21%	59,758	41.97%
Total	231,614		142,379	

Table 27 STOR providers by fuel type and approximate CO_2 emissions [80]

Chapter 9. The C2C method and network modelling

9.1. Outline of the C2C project

This section describes the C2C project and the analysis using network models of the C2C scheme, with particular reference to the Dickinson Street network. The C2C project undertaken by Electricity North West (ENW) was funded under the Ofgem LCNF program. The aim of the project was to release latent network capacity using a combination of automation, non-conventional network operating practices and commercial DSR. It also looked at customer acceptance to these changes. ENW noted that network investments driven by the planning standard, P2/6, essentially require that "for every extra 10MW of capacity required, 20MW of infrastructure is needed" and that this infrastructure would be paid for by customers in the form of higher network connection and use of system charges [81].

The current planning requirements are met by considering how demand will be met in case of a fault on one circuit (so called "N-1 fault"). Each HV feeder may be connected to a number of adjacent feeders. After a fault up to two switching operations are allowed on ENW networks in order to maintain security of supply and to minimise customer minutes lost (CML) [82] For this reason networks are usually designed with normally open point (NOP) connections that are typically only operated in the case of a fault or planned outage in order to supply power to the affected part of the network from a different circuit.

Figure 60a shows an example radial network running with the NOP open. In the case of a fault near the primary transformer the NOP will close as shown in Figure 60b and Figure 60c for faults at the left-hand and right-hand feeder respectively. This allows the supply of demand on the faulted feeder which would otherwise be cut-off.

ENW note that nearly half of circuits do not suffer faults and that a third experience faults which last 1 – 2 hours every five years [52]. It may therefore be argued that the required redundancy in the network is an inefficient use of assets. The C2C method seeks to utilise the inherent capacity in these redundant assets whilst maintaining security of supply as defined by P2/6.

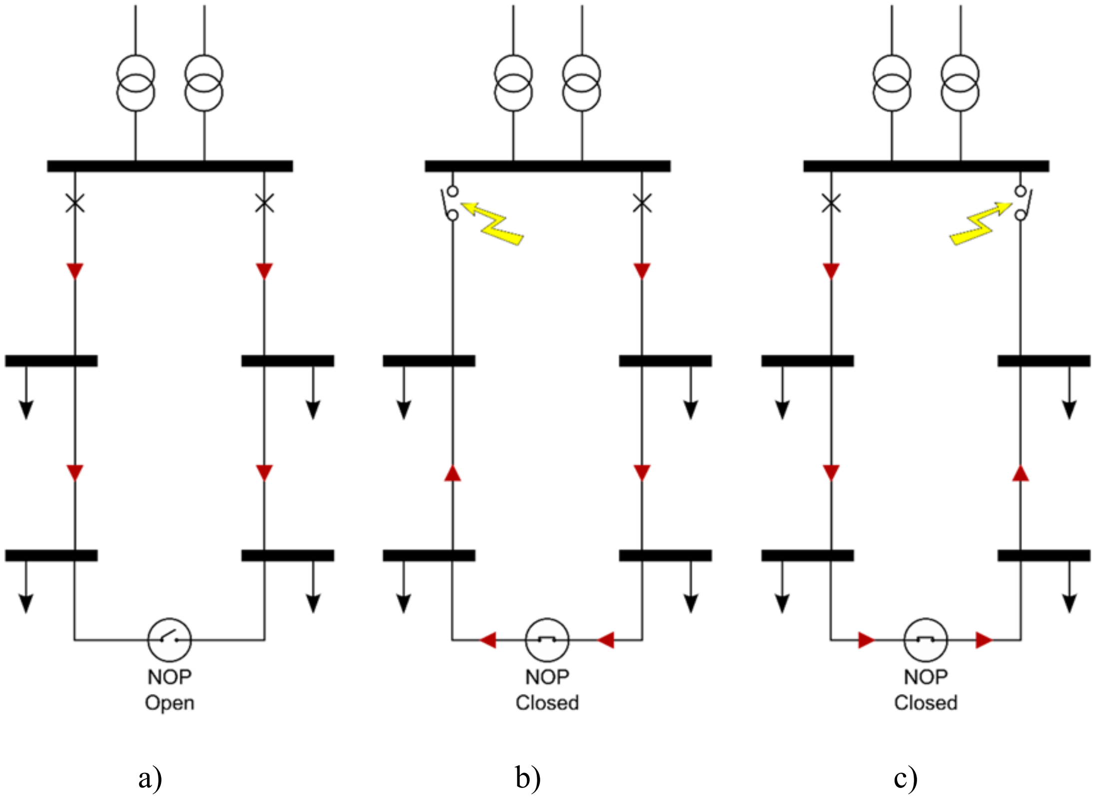


Figure 60 Network under (a) normal operation; (b) fault on left feeder; (c) fault on right feeder

9.2. The C2C Method

The C2C method releases additional capacity required by the planning standard by adding demand which can be curtailed in case of a fault to maintain security of supply. Using this method a DNO may be able to defer investment in network reinforcement and therefore make financial savings. Comparing the cost of adding C2C demand which can be immediately curtailed to the cost of network reinforcement, ENW state that the C2C solution is £0.37m whilst a standard solution is £7.84m [81]. These costs are ultimately borne by the electricity user in the form of DUoS charges. However, it should be noted that standard network reinforcement would offer more utility to the customer in that they would never be required to curtail demand for the purpose of meeting P2/6. The demand added above the P2/6 limit is subject to special connection agreements which are less costly but require that the demand is curtailed immediately in the event of a fault.

9.2.1. The C2C network operating configurations

Using 36 models the project tests two network operational configurations named: 'C2C radial' and 'C2C interconnected'. The C2C radial case considers the network with NOP open in normal operation. This is shown in Figure 61a where the additional C2C demand is shown in green. In the case of a fault the NOP is closed and the C2C demand is curtailed in order to maintain an unconstrained network in the fault condition. This is shown in Figure 61b which is equivalent to the situation in Figure 60b.

The C2C interconnected case operates with the NOP closed in the normal condition. In case of a fault the C2C demand is curtailed in order to maintain an unconstrained network in the fault condition.

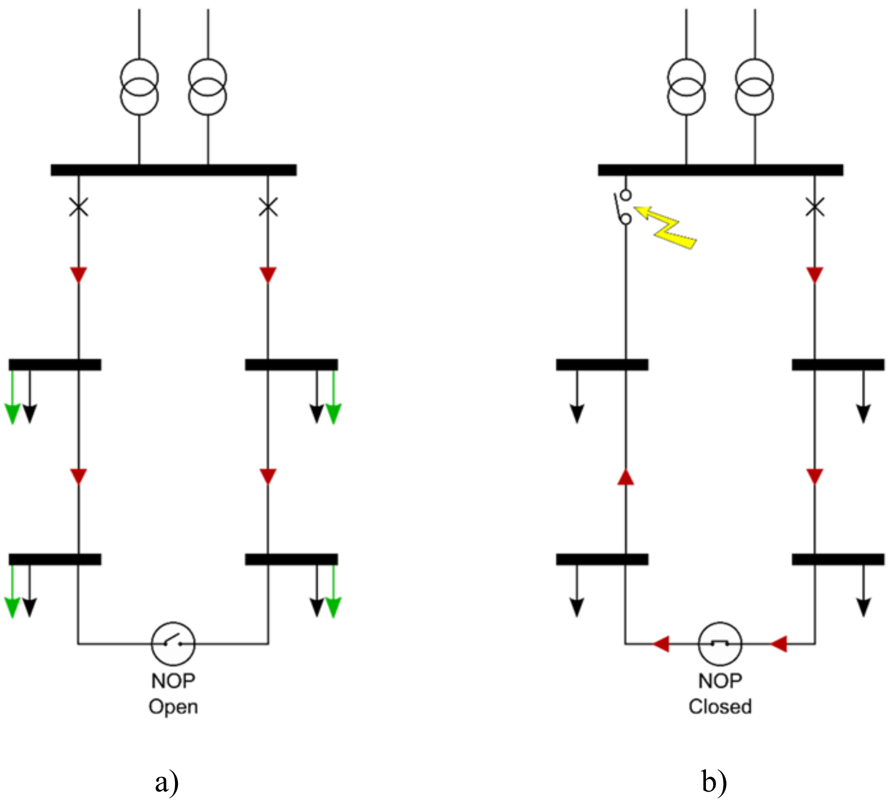


Figure 61 C2C Radial operation under (a) normal operation; and (b) fault condition

9.2.2. C2C Network contracts

The project demonstrated three ways in which C2C commercial arrangements could be implemented:

- Direct contract with the DNO
- Offering a finder's fee to aggregators but use a direct contract between the DNO and the C2C demand provider
- Contract with an aggregator using their equipment

ENW prefer direct engagement as it strengthened their relationship with the customer and was also the most cost effective [81]

The C2C project produced new contracts for new and existing customers to enable them to participate in DSR, either by demand reduction or demand side generation. In order to facilitate the replication of the commercial framework a series of 'commercial templates' were produced. These templates were applied to the 20 participants who signed up during the trial [81].

9.3. C2C network models

Blair and Booth [82] created network models in IPSA and used Python scripting in order to test the C2C hypothesis that the C2C method would release significant capacity to customers. Using graph theory, DINIS data and operational diagrams they extract ring circuits with NOPs from the ENW network. Then they exclude extraneous nodes including NOPs which connected to other parts of the network. This is shown in Figure 62.

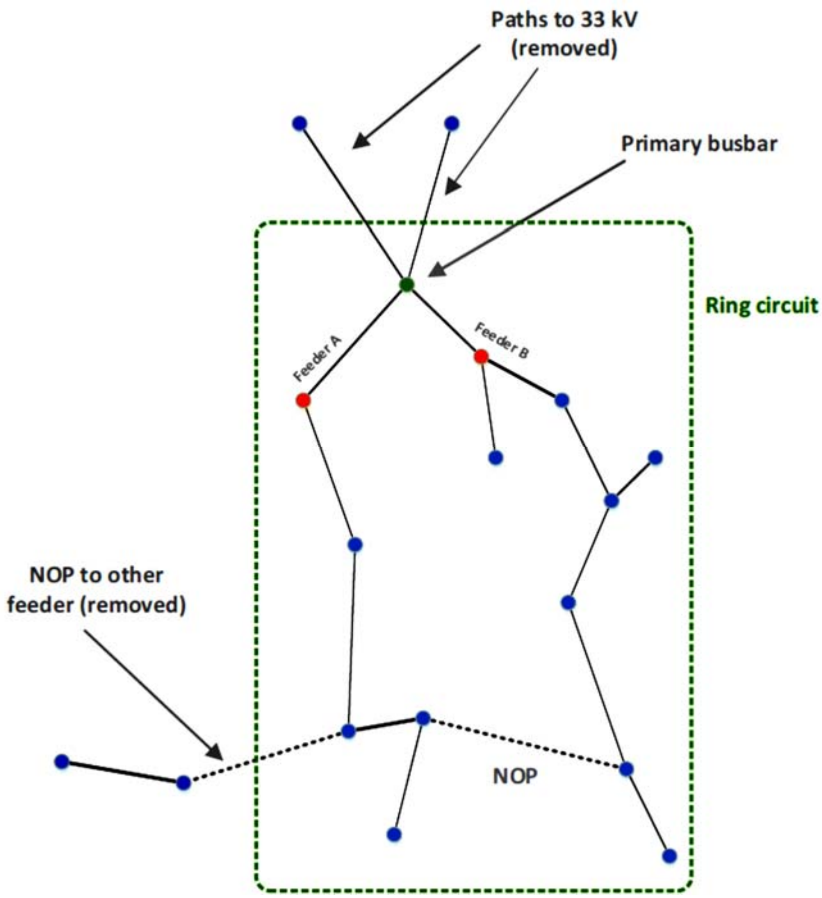


Figure 62 Extracting ring circuit nodes and branches (from [82])

Once the network model has been created in IPSA it is populated with demands based on transformer ratings or maximum demand indicators [82]. This demand set will be referred to as the *initial demand* and represents the current day peak demand. It should be noted that these peak demands may have occurred at different times of day and summing them together may somewhat exaggerate the peak magnitude since it ignores the temporal diversity of the individual demands.

IPSA models and demands for the Dickinson Street ring [83] were made available for the work described in this thesis. There are 3 models:

- firm base case
- C2C radial configuration
- C2C interconnected configuration

These are explained in more detail later. A visual assessment using Google maps [84] of the modelled area indicates that the network supplies mostly commercial properties such as offices, shops and restaurants as well as some residential demand.

9.3.1. Establishing a base case capacity

In order to assess the capacity released from C2C operation the base capacity to meet P2/6 in the current practice must be established. The following describes how this is calculated by Blair and Booth [82]. There are two stages to determining the base case capacity. First the *initial firm capacity* is calculated for the two-feeder network. This is the first point at which the network becomes constrained due to increasing demand. However, this value underestimates the actual capacity as it does not consider load support available from other backfeeds during a fault. These backfeeds were excluded from the model during the process of extracting the network ring. The second stage accounts for this to give the *base case capacity*, as described later.

The initial firm capacity is calculated as follows.

1) An open circuit is created on one of the feeders as close to the primary substation (slack bus) as possible. This simulates a worse case N-1 fault on that feeder.
2) The two feeders are joined at the NOP, so that the entire demand is supplied by a single feeder.
3) The initial demands on all buses are scaled linearly until a thermal or voltage constraint is reached and the scaling factor is noted.
4) The process is repeated but with the open circuit on the other feeder
5) The lowest scaling factor represents the worst case fault in terms of the level of demand that can be supplied and is therefore the maximum demand capacity multiplier possible while still complying with the P2/6 standard.

Since the initial firm capacity does not account for power available from backfeeds during a fault, the value is increased by 30% to give the base case capacity. The value of 30% is based on a comparison of historical peak data from the 36 modelled circuits against their calculated values of initial firm capacity [82]. Summary descriptions of initial firm and base firm demand are given in Table 28.

9.3.2. C2C network demand scaling factor

The C2C regime operates by increasing demand above the base case capacity with loads that can be curtailed in the event of a fault. Therefore these loads do not affect the ability to meet the technical requirement of P2/6, since they do not form a part of the fault condition demand.

The C2C capacity is the maximum demand in the non-fault condition. To determine this, the demands are scaled equally until a voltage or thermal constraint is reached. The scaling factor just before the constraint gives a measure of the increased capacity, under the assumption that all demand on the network grows at the same rate. The scaling factor is determined in this way for the C2C radial network (NOP open) and the C2C interconnected network (NOP closed).

Table 28 shows a summary of the demand capacity levels and descriptions. Note that the initial firm demand set is discovered using the firm base case model and that the base firm is this demand scaled by 30%. That is to say that the firm base case model is used to give both ratings.

9.3.3. IPSA Dickinson Street network model verification

Figure 63 shows a geographical representation of the network model used for this work, based on the IPSA model received from Steven M. Blair [83]. There are two points on the network where multiple features have been added at the same point. For these the node numbers (generated for Matpower after conversion from IPSA) are shown grouped around an arc. These computer generated components are given artificially high ratings in order that the constraint solution is found within the network lines of interest. The normally open point (NOP) is shown in green between The Art House and node 24. This separates the two feeders: the Art Gallery Feeder (blue) and the Tuscany House feeder (red and pink).

Demand Rating	Description	NOP in non-fault condition	Relevant Model
Initial Demand	Current day demand set	n/a	n/a
Initial firm	Initial Demand increased until a constraint occurs in the model	Open	Firm base case
Base Firm	Initial firm increased by 30% to account for load support from other backfeeds during fault. Considered to just meet P2/6	Open	(Firm base case)
C2C Radial	Radial configuration (NOP open) which allows for capacity beyond base firm by adding demand which must be curtailable in the event of a fault, until a constraint occurs in the model	Open	C2C radial
C2C Interconnected	Interconnected configuration (NOP closed) which allows for capacity beyond base firm by adding demand which must be curtailable in the event of a fault, until a constraint occurs in the model	Closed	C2C interconnected

Table 28 Summary of the demand capacity levels and descriptions and NOP status.

The network has been re-formulated in Figure 64. For clarity many of the computer generated nodes have been reduced in number. Where there was a cluster of these nodes it is indicated by a grey box. The NOP is shown as a dotted line between node 24 and The Art House.

The line ratings are given in Table 29.

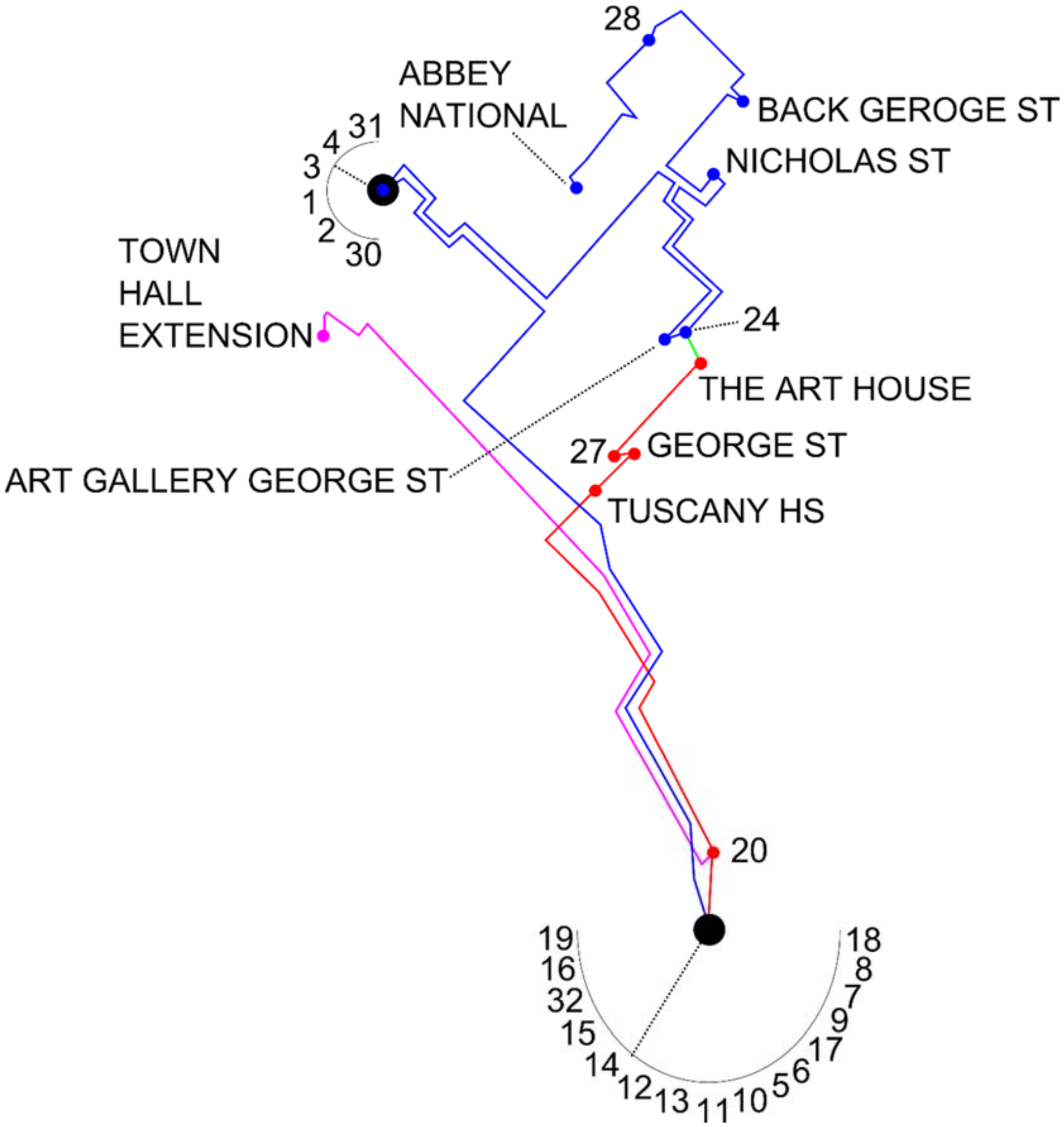


Figure 63 C2C network model for Dickinson St, redrawn from [82]

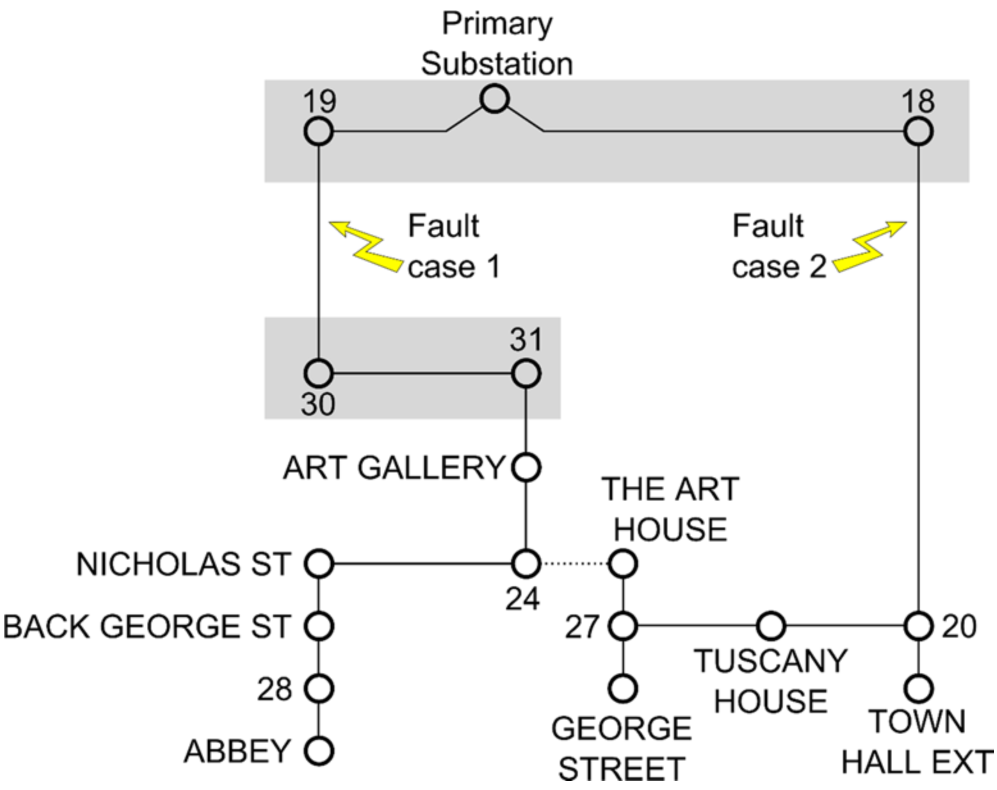


Figure 64 Diagram of network

From	To	MVA	kA
20	TOWN HALL EXTENSION	5.256	0.459781
19	30	5.256	0.459781
ART GALLERY GEORGE ST	31	4.572	0.399946
NICHOLAS ST	24	5.43	0.475002
20	18	5.256	0.459781
THE ART HOUSE	24	7.716	0.674975
THE ART HOUSE	27	7.716	0.674975
24	ART GALLERY GEORGE ST	4.572	0.399946
GEORGE ST	27	5.256	0.459781
TUSCANY HS	20	5.256	0.459781
27	TUSCANY HS	5.256	0.459781
NICHOLAS ST	BACK GEORGE ST	5.43	0.475002
28	ABBEY NATIONAL	5.256	0.459781
BACK GEORGE ST	28	5.256	0.459781

Table 29 Dickinson St network model line ratings

9.3.4. Determining the base firm capacity

The *base firm capacity* refers to the level of demand a network can accommodate in the worst case fault condition.

The worst case fault is one which occurs near to the primary substation and requires all the demand to be supplied by one feeder of the pair. For the network model in question there are two possible cases for this since there are two feeders. In the IPSA model the lines near the substation buses (19:30 and 20:18) are set to 'out of circuit' alternately in order to determine which fault is the worst case for this demand set. For each case the IPSA scaling factor was manually altered until the value at which it caused a constraint was determined. Setting branch 19:30 out of service there was a thermal constraint in branch 20:18 at a scaling value of 1.48. However with branch 20:18 out of service there were thermal constraints at a lower scaling factor of 1.27. These occurred in branches ART GALLERY:31 and19:30. Therefore the initial firm capacity scaling factor is 1.27, since this is the lower set of demands.

The base firm capacity includes an assumed 30% capacity from backfeeds on top of the initial firm capacity. Therefore the scaling factor relative to current day demand for base firm capacity is 1.65. This is close to the value of 1.66 in the C2C work. In work that follows the value of 1.66 will be used.

9.3.5. Determining the C2C radial capacity

For the IPSA model in radial configuration the method of changing the demand scaling factor manually was used again in order to determine point of constraint. This gave:

$$\text{demand scaling factor}_{\text{radial}} = 2.50$$

Recalling that the base case is the maximum scaled demand set which meets P2/6, the scaled demand relative to the base case represents the increase in demand capacity due to the C2C method. This is calculated as the relative scaling factor below. The relative scaling factor is determined with reference to the base case scaling factor, which was 1.66:

$$\text{relative demand scaling factor}_{\text{radial}} = \frac{2.50}{1.66} = 1.51$$

9.3.6. Determining the C2C interconnected capacity

Manually manipulating the scaling factor as before the network was found to constrain at a scaling factor of 1.80:

$$\text{demand scaling factor}_{\text{interconnected}} = 1.00 \times 1.80 = 1.80$$

The scaled demand, which represents the increase in demand capacity due to the C2C method is calculated relative to the base case of 1.66:

$$\text{relative demand scaling factor}_{\text{interconnected}} = \frac{1.80}{1.66} = 1.08$$

9.3.6.1. Verifying the results against the values obtained in C2C project

The increase in demand capacity for C2C radial and C2C interconnected networks obtained in the C2C project are given in a bar chart for all 36 of the modelled networks in the project [82, Fig. 15]. Due to the relatively small size of the chart it is not possible to read off values with great precision but the values for Dickinson Street are approximately 150% and 110% for radial and interconnected respectively which agree with the scaling values of 1.51 and 1.08.

9.4. Summary

Table 30 summarizes the values calculated in this section. The base case demands are 1.66 times the initial demand set. The relative demand scaling factors are 1.52 and 1.08 for the C2C radial and C2C interconnected networks.

Model	Demand set	Scale factor relative to initial demand set	Scale factor relative to initial firm capacity	Scale factor relative to base capacity demand set
Radial Firm	Initial firm	1.27	1.00	n/a
	Base capacity	1.66	1.30	1.00
C2C Radial	C2C Radial capacity	n/a	2.51	**1.51**
C2C Interconn	C2C Interconn capacity	n/a	1.80	**1.08**

Table 30 Summary of how scaling factors relate to initial firm and base capacity demand sets

9.5. Conversion of the IPSA model into the software suite

9.5.1. Introduction

Since the software suite developed by the author uses Matpower for the power flow calculations the IPSA models need to be converted to Matpower format. The following describes how the C2C IPSA network models are converted to Matpower models and integrated into the MATLAB software suite described in Appendix B. The C2C work described in sections 9.3.3 to 9.3.6 is replicated where possible to verify that the new MATLAB software produces reasonable results. The MATLAB software has been designed to work with demand profiles but the C2C work considers only single valued peak demands. In the work described here the time axis of the models effectively becomes a proxy for the scaling factor through the use of linearly ramping profile data (i.e. the time is proportional to the value or scaling factor of the demand). This is done so that the C2C results may be directly compared with the model results.

9.5.2. Conversion of C2C IPSA model to MATLAB

This section describes converting the previously described C2C IPSA network model into MATLAB models. The first stage is to convert the IPSA models from [83] into *powerNetwork* objects which were described in section 6.3.4.

The class *powerNetwork* was developed to provide an interface between Matpower and other classes developed in MATLAB. This class is an interface to a Matpower network model and only operates with a single value of demand not a profile. In other words it has no knowledge of time.

The following describes the process of converting IPSA data into the format for Matpower which can then be used to create a *powerNetwork* object and is shown in Figure 65. A spreadsheet template specifically developed for the conversion process is manually populated with data from the IPSA by copy and pasting values from the IPSA model including: base MVA; base kV; line impedances; line ratings; loads and the location of the grid infeed (i.e. the slack bus). A MATLAB script was written to extract data from this spreadsheet to create a data structure in the correct format for Matpower. In the Matpower documentation this structure is named *mpc*. The *powerNetwork* object can then be created in MATLAB which includes this data structure.

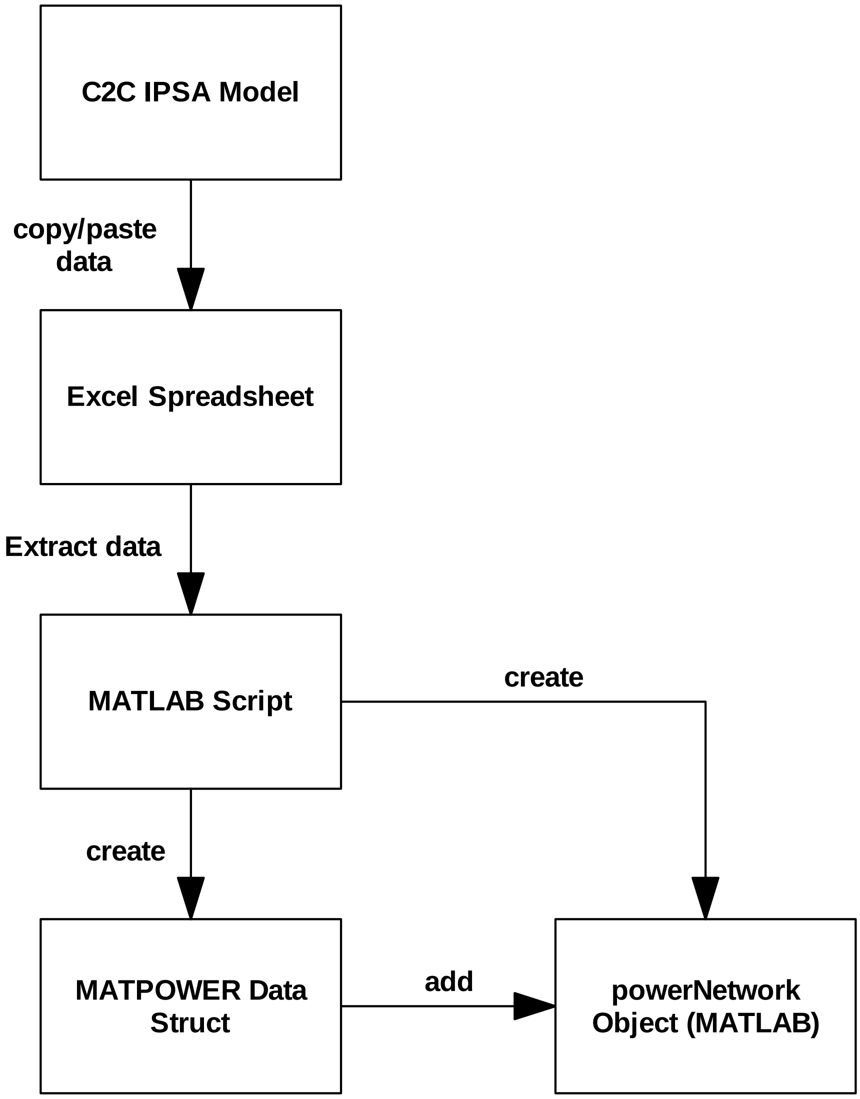


Figure 65 Process for converting IPSA model data to a powerNetwork object

9.5.3. The networkRunner class

The *powerNetwork* class is an interface to a Matpower network which can run a power flow using single valued demand on each bus bar. In other words, in common with IPSA and Matpower, it is ignorant of the time dimension of demand and does not process time varying demand profiles. The *networkRunner* class, however, was developed to process demand profile data by calling the *powerNetwork* object multiple times in order to generate a set of sequential power flow results with respect to time. Referring to the class diagram in Figure 66 the *networkRunner* object is linked with *powerAgents* which are connected to different buses on the network model. The *powerAgents* contain the demand profile data and the *networkRunner* supplies the demand profile data to the *powerNetwork* object one data point at a time, running a power flow at each time point.

In Matpower each bus is defined by a number but the *powerNetwork* class uses a custom data-type called *networkLocation* to define each bus. This data-type includes the Matpower bus number and a text name and (optional) description. The buses in *networkRunner* are inherited from the *powerNetwork* that is associated with it.

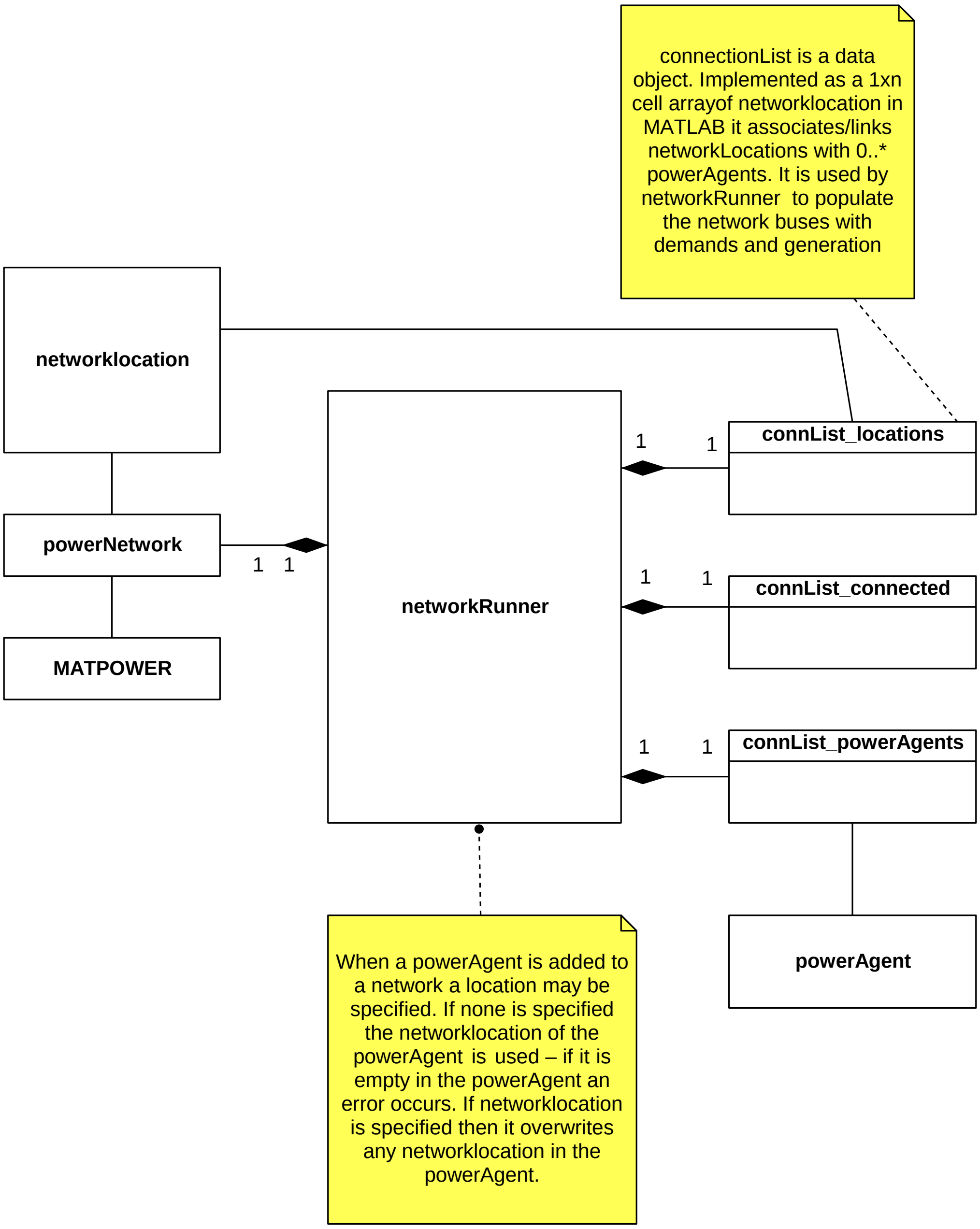


Figure 66 Class diagram of the networkRunner class

9.5.4. Verification of the powerNetwork model against C2C results

The *powerNetwork* created has demands as shown in Table 31 which are inherited from the IPSA model (via the spread-sheet template). These are the initial firm capacity demands (taken from the IPSA base case model) multiplied by the scaling factor in the

IPSA base case model, which is 1.66. This demand set represents the base case firm demand (see Table 28) which just meets the P2/6 criteria.

Bus Bar	Real Demand	Reactive Demand
ART GALLERY GEORGE ST	715.9580	235.3233i
NICHOLAS ST	946.2000	311.0010i
THE ART HOUSE	441.5600	145.1338i
GEORGE ST	383.2110	125.9553i
TUSCANY HS	525.1410	172.6051i
BACK GEORGE ST	906.7750	298.0430i
MAN TOWN HALL EXTENSION	1419.3000	466.5015i
ABBEY NATIONAL	241.2810	79.3052i

Table 31 Demand set which represents the base case demand.

A direct comparison of networkRunner results with C2C IPSA model results is not possible since the C2C data has single value demands whereas the networkRunner uses demand profiles which vary with time. The networkRunner was tested in the following way. The single valued demands were scaled to produce a ramp profile with time. This means that the time axis can be used as a proxy for the scale factor of the single valued demands. The ramp profile is from 0 to 10 times the demands shown Table 31

In order to test and verify the *networkRunner* an instance of it is created using a *powerNetwork* object and the ramp demand profiles are linked to it. A MATLAB script was written to find the scaling factor at which the network becomes constrained (see section 6.3.5). This is achieved by running a powerflow analysis in the *networkRunner* with different scaling factors by selecting different time points. The scaling factor value is converted to a time value, based on the fact that the profile is a linear ramp shape. The scaling factors are chosen based on a binary search algorithm in order to determine the point at which the network becomes constrained. The binary search algorithm is described later in section 10.4 and Figure 73.

Verification tests were conducted for the radial network and the interconnected network. The radial network was found to be thermally constrained on the line ART GALLERY GEORGE ST:31 at a scale value of 1.53, whilst the interconnected network was thermally constrained on the line 20:18 at a scale value of 1.08. A comparison of the results against those obtained by manual scaling of the demand in IPSA (in sections 9.3.5 and 9.3.6) is given in Table 32. It can be seen that for the radial network case the difference is around 1%.and for the interconnected network the values are the same within the precision of the scale factor.

Circuit Type	MATLAB Models Scale factor lower bound	MATLAB Models Scale factor upper bound	Scale factors determined in IPSA network models	Difference
Radial	1.526	1.527	1.51	~1%
Interconnected	1.081	1.082	1.08	< precision

Table 32 Comparison of scaling factor determined from MATLAB models and IPSA

9.6. C2C Demand Data for Modelling

9.6.1. Introduction

This section describes the data and decisions made in order to create a representative set of demand profiles for the network model based on a day of peak GB-wide demand. The aim is to model a part of the Dickinson Street network on a day with high demand. Triads represent the total network highest peak half-hours [38] and so where possible demand profile data for the highest Triad was used to obtain a representative demand shape for a peak demand day. The highest Triad demand in 2013/14 was Monday 25th November 2013 at 17.00 - 17.30 and so data from this day was used where possible. The second largest Triad demand was Thursday 30th January 2014 17.00 - 17.30 and the smallest was on Friday 6th December 2013 17.00 - 17.30. If no data is available on a Triad day then a judgement is made on the weekday of highest apparent demand for that busbar.

9.6.2. Sources for demand data

Most of the demand data is taken from [85]. Not all of the busbars were monitored and so substitute data had to be used those busbars.

Table **33** shows the date of data used for each busbar or ‘none’ for the three busbars for which there was no data available. It also shows the amount of data available in days. For the busbars without data substitute data was used as shown in Table 34.

Table 34Demand data for Art Gallery George Street busbar was substituted with data from the Birmingham Museum and Gallery (BMAG), available from the Smart Spaces website [86]. This data is half-hourly and does not have reactive power. Demand data was not available for 2013/14 so the peak Triad day in 2014/15 (19th January 2015) was selected. Since this data set is only half-hourly it was interpolated to give 5 minute data. The data contains only real demand and reactive demand was synthesized using the power factor for The Art Gallery calculated from data in Table 37. This is described in section 9.6.4.

Data for George Street was taken from the data available for Back George St., using a different day to the data used for Back George Street. Data was available for Manchester Town Hall and this was used to represent the demand shape for the Manchester Town Hall Extension.

Bus Bar	Date of Data	Amount of C2C data
Art Gallery George St.	*none*	*none*
Nicholas Street	Tue 12-Mar-13	65 days
The Art House	Mon 25-Nov-13	347 days
George St.	*none*	*none*
Tuscany House	Mon 25-Nov-13	425 days
Back George St.	Mon 25-Nov-13	440 days
Man Town Hall Extension	*none*	*none*
Abbey National	Wed 19-Jun-13	12 days

Table 33 Dates of busbar data used for the demand profiles

Bus Bar	Substitute Data	Date of Data
Art Gallery George St.	Birmingham Museums And Galleries	Mon 19-Jan-15
George St.	Back George St	Thu 30-Jan-14
Man Town Hall Extension	Manchester Town Hall	Mon 25-Nov-13

Table 34 Substitute data used for busbars with no available data

9.6.3. Adjusting for daylight savings on Abbey National demand data

In the year 2013 the period of daylight saving time (DST) ran from 31st March until Sunday 27th October. The Abbey National data falls within this period. Checking the data for Manchester Town it was found that the timestamps increase linearly for the hours around the changes to DST indicating that the monitoring data is not adjusted for DST. This makes sense as if it had been adjusted for DST it would introduce discontinuities and overlaps in the data. To account for the change in time the data from Abbey National was set back by one hour. In other words 24 hours of data starting at 23:00 was used to represent data starting at 00:00.

9.6.4. Synthesizing reactive power data for the Art Gallery George St bus bar.

The demand data for the Birmingham Museum and Gallery does not contain reactive power. A single value for the power factor was calculated from the IPSA network model. First the apparent power is calculated using data for the Art Gallery in Table 37:

$$\text{apparent power} = \sqrt{(\text{real power})^{\mathbf{2}} + (\text{reactive power})^{\mathbf{2}}} \tag{3}$$

$$= \sqrt{\mathbf{0.4313^2} + \mathbf{0.1418^2}} = \mathbf{0.4540}\ \text{MVA} \tag{4}$$

Then the value for apparent power is substituted into the equation for power factor:

$$\text{power factor} = \frac{\text{real power}}{\text{apparent power}} \tag{5}$$

$$\text{power factor} = \frac{\mathbf{0.4313}}{\mathbf{0.4540}} = \mathbf{0.95} \tag{6}$$

9.6.5. Checking the real and reactive power data

Demand data for all the buses was downloaded from [85] and stored in Excel spreadsheets with the real and reactive demand profiles stored in separate spreadsheets. A MATLAB script was written to take data from these spreadsheets to determine the complex value of demand at each time point for all the buses represented. In order to sense check the data, the script calculates and displays the maximum, minimum and mean power factor. The values are shown in under the column ‘Original Data’. For the demands on bus bars AbbeyNat_DSToffset and ManchesterTownHall the power factors seem low, and at TuscanyHouse the power factor has a wide range of values. This could be due to data recording errors, for example incorrect labelling of real and reactive power data. For the three bus bars mentioned the real and reactive demand datasets were swapped (data designated as real demand becomes reactive demand and vice-versa). Executing the script again gives the power factors shown in the modified data column of Table 35. A judgement call was made to use the data that produced the modified power factors for the three buses in question, as these values are closer to what would be expected. The script produces variables that contain the complex demand data for each bus, rather than having separate variables for real and reactive demand as in the original data.

A column vector of dates/times is created from 25-Nov-13 from 00:00:00 to 26-Nov-13 23:55:00. Although the analysis takes place over a single day, some of the effects of DSR occur later in the next day so variable space allocated for that by copying the demand to give two days of data. This data is saved as a MATLAB file *DickinsonSt_Demands_pfChecked_2day.mat* and contains data described in Table 36.

Demand Data Bus Bar (spreadsheet name)	Original Data			Modified Data		
	Max	Mean	Min	Max	Mean	Min
AbbeyNat_DSToffset	0.55	0.42	0.33	**0.94**	**0.91**	**0.84**
BMAG	0.95	0.95	0.95	-	-	-
BkGeorgeSt_140130	0.99	0.93	0.84	-	-	-
BkGeorgeSt	0.99	0.92	0.77	-	-	-
ManchesterTownHall	0.56	0.39	0.23	**0.97**	**0.92**	**0.83**
NicholasSt	0.95	0.93	0.86	-	-	-
TheArtHouse	1.00	1.00	0.99	-	-	-
TuscanyHouse	0.97	0.67	0.11	**0.99**	**0.69**	**0.22**

Table 35 Bus bar demand power factor characteristics before and after manipulating the data

Variable name	Description
readme_dateTimes	Text describes date range of dateTimes variable
dateTimes	Date and Time index (column vector)
AbbeyNat_DSToffset	Complex demand data at each date/time point
BkGeorgeSt	
BkGeorgeSt_140130	
BMAG	
BMAG_5min_data	
ManchesterTownHall	
NicholasSt	
TheArtHouse	
TuscanyHouse	

Table 36 Description of demand and associated data saved to MATLAB

9.6.6. Demand scaling

A MATLAB script was written to scale all the demands such that the peak of real demand on each bus is the same as the real demands on the IPSA model in Table 37. The data in this table is the base demand from the IPSA models and represents the maximum demand which is still P2/6 compliant.

Busbar	Real Power (MW)	Reactive Power (MVAr)
MAN TOWN HALL EXTENSION	0.855	0.281025
THE ART HOUSE	0.266	0.08743
ART GALLERY GEORGE ST	0.4313	0.141761
GEORGE ST	0.23085	0.0758767
TUSCANY HS	0.31635	0.103979
NICHOLAS ST	0.57	0.18735
ABBEY NATIONAL	0.14535	0.0477742
BACK GEORGE ST	0.54625	0.179544

Table 37 Load data taken from IPSA model (Dickinson St radial firm capacity)

9.6.7. Creating the data objects for the model

The previous sections describe how the demand data sets are produced. These demand sets as well as a date/time index are saved as a MATLAB data file in the format shown in Table 36. A MATLAB script uses this demand data to create powerAgents with the demand data at the relevant bus bar locations. The *reboundFactor* and *reboundTimeLimitHours* are required to be set when the powerAgents are created but these will be altered later. The powerAgents are saved as a MATLAB file which contains the data listed in Table 38. The powerAgents are created with empty location data because the location references an object and the location object is created separately and will be added later.

Variable name	Description
dateTimes	Date and time index
emptyLoc	Empty object of type networklocation
pA_AbbeyNat	Power agents
pA_ArtGalleryGeorgeSt	
pA_BkGeorgeSt	
pA_GeorgeSt	
pA_ManchesterTownHall	
pA_NicholasSt	
pA_TheArtHouse	
pA_TuscanyHouse	
readme_dateTimes	Readme note
reboundFactor	Initial/dummy value for the rebound factor
reboundTimeLimitHours	Initial/dummy value for the rebound time duration

Table 38 Variables and *powerAgents* saved to MATLAB file.

A MATLAB script takes the saved *powerNetwork* described previously (see Table 38) and uses them to create a network runner. The script scales the demands to the base demand for the network (taken from the powerNetwork) and adds locations to the powerAgents before adding them to the networkRunner. It displays the *powerAgent* name along with it's location to help identify any errors. The *networkRunner* along with *dateTimes* (and also *powerAgents*, *nPAgents*, *reboundTimeLimit*, *reboundFactor*) are saved as *DickinsonSt_nRunner_scaledToBaseDemand_2day.mat*

9.6.8. Creating the networkRunner

A class *powerNetwork* was developed (as described in section 6.3.4) to provide an interface between Matpower and other classes developed in MATLAB. This class is an interface to a Matpower network model but only operates with a single value of demand not a profile. In other words it has no knowledge of time. The function of the *networkRunner* class is to take demand profile data and run a set of sequential power flows on a *powerNetwork* in order to produce power flow results with time. A *networkRunner* object should be populated with *powerAgents* which are then connected to different buses on the network model. The bus location is set with a data object of type *networkLocation*.

A *networkRunner* object is created from the *powerNetwork* and *powerAgents* objects as shown in Figure 27. The *networklocation* data objects contained in the *powerNetwork* are copied to the *powerAgents*. This links the *powerAgents* to the buses on the network. The demands on the *powerAgents* are scaled such that the peak demand for each demand is equal to the base demand from the *powerNetwork* model. It should be noted that the IPSA model operates at a single point in time but this scaling process operates on demand profiles which may have their peaks at different times. Therefore the peak demand of a model described by the *networkRunner* is likely to be different to the total demand of the IPSA model.

Simulations can be undertaken by loading a *networkRunner* which has been created for a particular network and set of demands. The demand and rebound characteristics can be altered in the *powerAgents* to model different scenarios.

Chapter 10. Network capacity reduction due to DSR by demand reduction with demand recovery

10.1. Introduction

Many DSR services called by the TSO are likely to be enacted by units (generation or loads) connected to the distribution network. These calls will have some affect on the power flow in the distribution network. Under a scenario with significant penetration of DSR providers on the same primary substation feeders the effect may be significant and may increase or decrease the network capacity headroom. For example DSR by demand reduction by a significant number of loads on the network feeder may reduce DNO network congestion. However, for demands with inherent storage there may be a recovery peak when the DSR request is terminated. This peak could have an adverse effect on DNO network congestion.

Figure 67 shows the actors and revenue flows relevant to this chapter. It also indicates the flow of electricity since the work in this chapter considers DSR interactions with the distribution network. DSR considered in this chapter is generalised to consider any type of service. Therefore the diagram indicates TNO use-of-system charges (which may result in Triad avoidance strategies) and services procured by the SO which the electricity user may participate in.

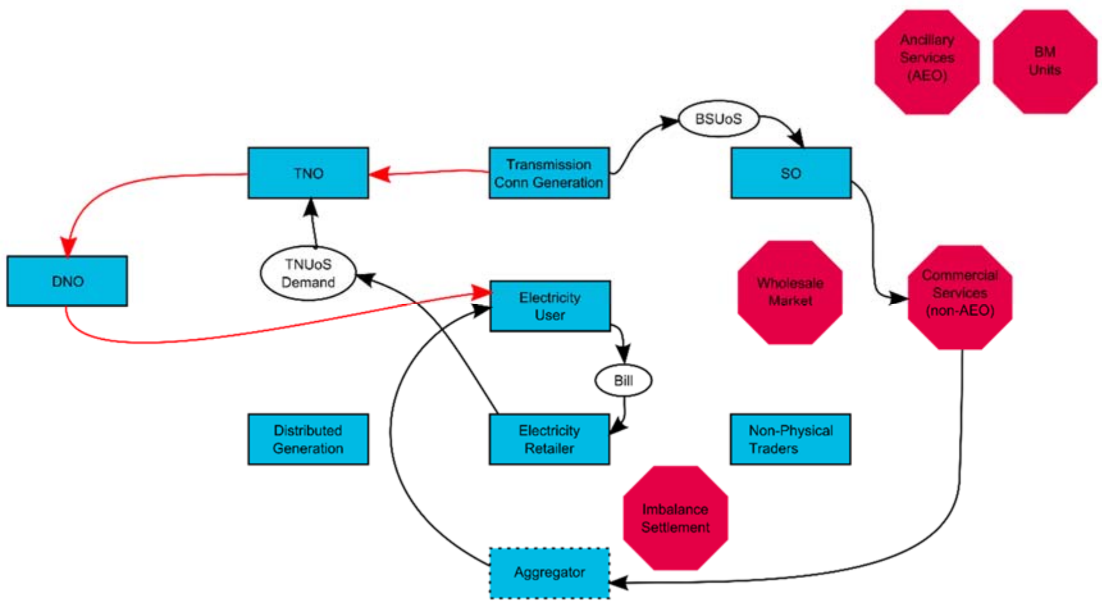


Figure 67 Actors, revenue and electricity flows relevant to this chapter

In section 3.5 it was seen that the time diversity of demand allows network designers to set the power capacities of assets on a particular part of the network significantly lower than they would if they did not account for diversity. Whilst they have diversity in the time domain, the fact that they are the same part of the network could be considered as a locational non-diversity.

For demands subject to recovery, located under the same primary taking part in the same DSR call may result in a synchronised demand recovery. This synchronisation represents a lack of diversity in the time domain.

The work in the C2C project considers peak demand at each secondary. The network is assessed with unsynchronised peaks as if they occurred at the same point in time. In effect it assumes a lack of diversity in the time domain.

The previous chapter described the C2C network regime and described the Dickinson Street network. It then explained how an IPSA model of the Dickinson Street was converted to a network model in the software suite and how demand profiles were embedded into *powerAgent* models. This chapter uses those software models to determine the reduction in capacity headroom on distribution network feeders due to demand reduction with different degrees of demand recovery. Demand side reduction with demand recovery is modelled on a part of the Dickinson Street network. The reduction in demand capacity headroom due to TSO DSR provision at the distribution network level is quantified.

10.2. Demand peaking at a secondary transformer due to DSR provision by multiple demands with energy recovery

This section gives examples of how demand recovery may:

- have no effect on the peak demand;
- increase peak demand;
- or decrease peak demand

A DSR call which is serviced by a customer on the distribution network may decrease or increase that customer's peak demand depending on the time of the DSR call and whether the DSR is subject to demand recovery (see section 4.3.2). Figure 68 shows the demand on a secondary transformer taken from C2C data [85] for a customer with and without a modelled DSR call at 04:00 hours. It can be seen that the demand recovery, which starts at 06:00, does not affect the peak for this particular demand. Figure 69 shows the demand on the same secondary transformer for the same customer with a modelled DSR call at 12:00. In this case the demand recovery, which starts at 14:00, increases the peak demand. Figure 70 shows a modelled DSR call at about 11:00 that reduces the peak which would normally have occurred before 12:00. The demand recovery which starts at 13:00 does not cause a new peak. The time of the new peak demand is now around 16:00.

The examples given here apply to an individual customer in order to explain the concept. The situation across a network is more complex due to the network characteristics such as topology and asset impedances and also due to the demand profiles.

An increase in peak demand for an individual customer on a secondary transformer (as seen in Figure 69) may or may not cause issues on the network, depending on the combination of: demand profiles at secondary transformers; their locations on the network; and the network impedances.

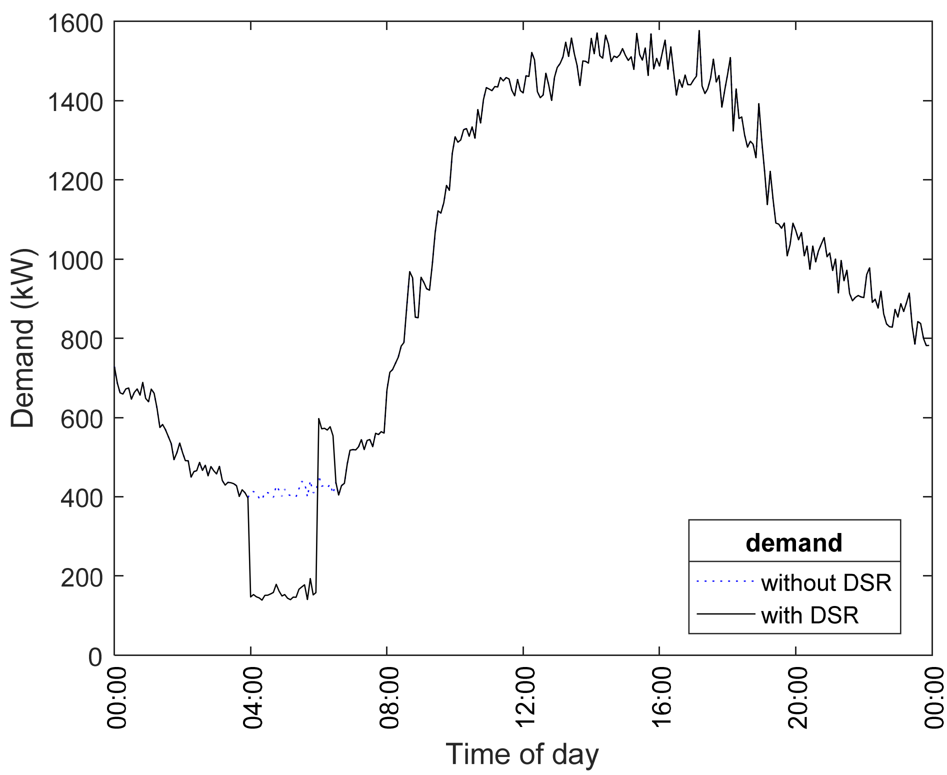


Figure 68 For DSR call at 04:00 the demand recovery does not affect the peak demand

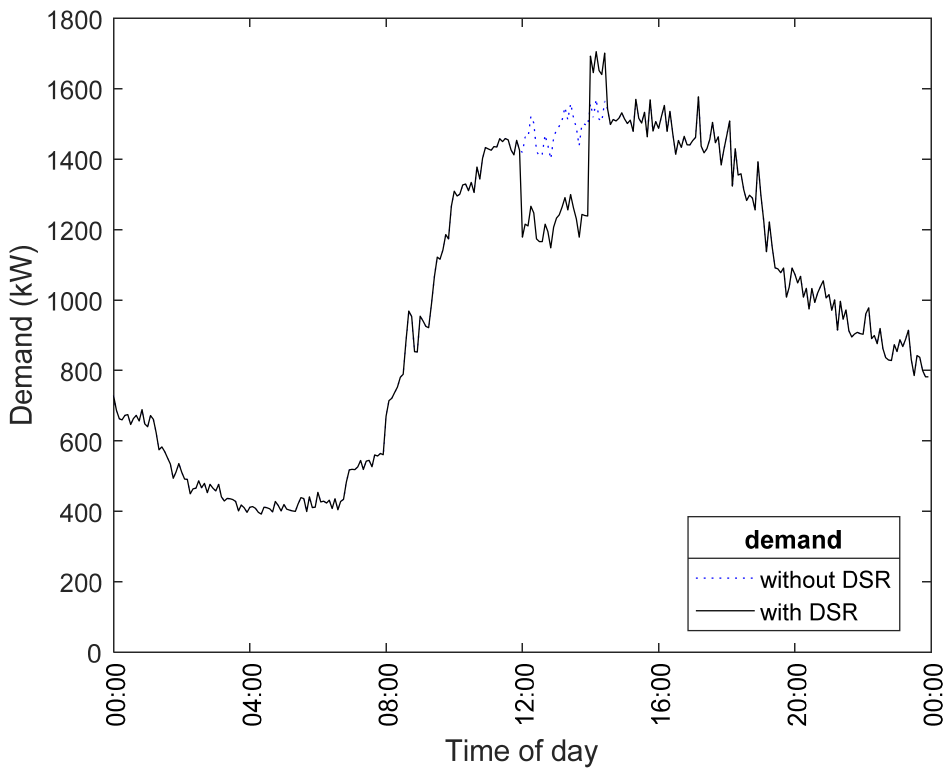


Figure 69 For DSR call at 12:00 the demand recovery increases the peak demand

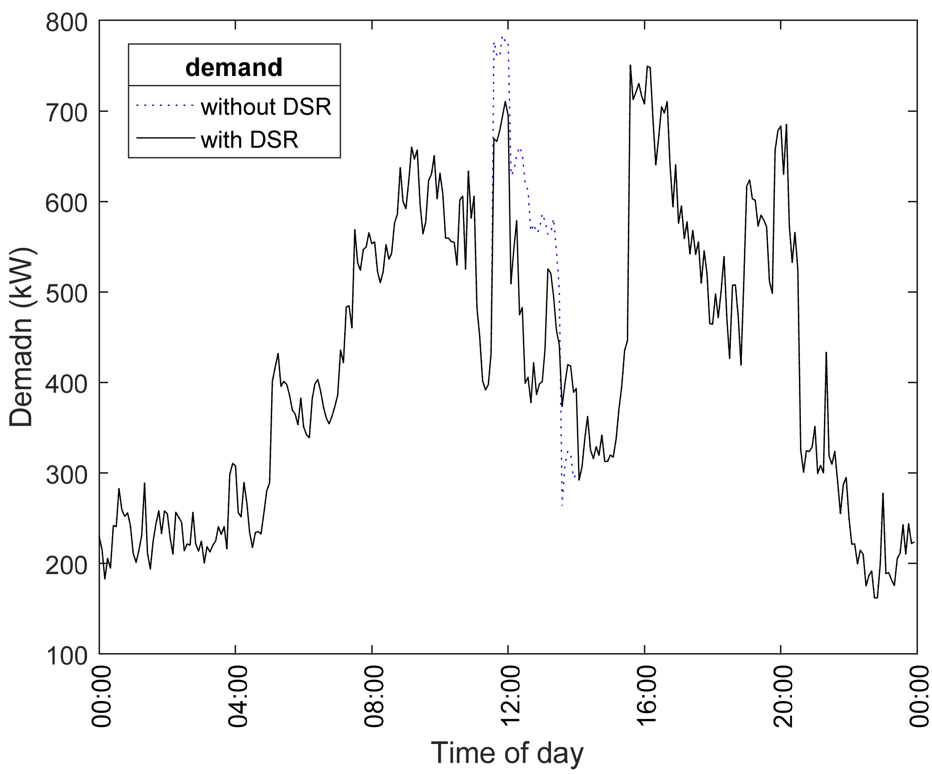


Figure 70 For some demands and DSR call timing the call may decrease peak demand

10.3. Network capacity factor

The C2C project [82] quantified the demand capacity of a network by scaling the peak demand linearly at all busbars until the network became constrained. The constraint could be thermal or statutory voltage level violation. This limiting scale factor will be referred to as the network capacity factor. It represents the amount of demand growth that the network can support, assuming that demand grows linearly. Therefore it is a function both of the network topology and impedances, as well as the current demands and their locations on the network. A factor of 1 would indicate that the network is running at its limit and has no capacity headroom. A factor of 2 would mean that the demand could increase by 100% (i.e. double), assuming linear demand growth, before the network became constrained.

This work uses the same method but considers demand across the whole day, not just the peak demand, calculating the scaling factor for every time point of the day. This is described in detail in section 10.4. The work here considers demand profiles across each secondary transformer, in contrast to the C2C work which calculates the scaling factor for a single set of peak demands. The demand scaling factor will vary at different times of day, since the demands vary across the day. For times of light demand the scaling factor will be relatively large compared to times of peak demand. Conversely at times when the network is heavily loaded the scaling factor will be smaller. This is shown in Figure 71 where the scaling factor is lower in the middle of the day, because the demand (not shown) is higher at this time. The demands at the middle of the day cannot be scaled up as much as the demands in the morning. The value at the lowest scaling factor is interpreted as corresponding to the network capacity factor as given in the C2C work and will be referred to as such. This is indicated by the dashed line in Figure 71 which shows a network capacity factor of 1.6. This would be the value used for operational planning and means that the demand could be increased 160% of the current value, assuming linear load growth. Put another way, the capacity headroom is 60%. The scaling factor (solid line) will be referred to as the demand scaling factor. To recap:

$$\text{network capacity factor} = min(\text{demand scaling factor})$$

Since the demand scaling factor is determined with respect to the current demands, this measure accounts for both the ratings of its assets and also on the real and reactive power and network locations of demands. These factors combine in a non-trivial way. For example, a network with heavy loading at a weaker part of the network will become constrained at a lower scaling factor than the same network with the same total demand but more heavily loaded near the primary transformer, since the total power transferred through the network cables nearer to the primary transformer would be greater.

The network capacity could be increased if demands were reduced at certain times of day. The demands which would need to be reduced depends on the location of those demands and on the network topology and impedances.

A significant assumption in this method, as with the C2C method, is that all the demands grow linearly from the current day values.

In the C2C work the network capacity was calculated on peak demand values without consideration for the timing of those values. In the analysis it is as if the peak values occurred simultaneously. Since the capacity scale factor in Figure 71 includes demand profiles with time, the diversity of peaks is considered in the analysis for the work described here. Since this work used profiles with the same peak values as those in the C2C work, the calculated network capacity factor must be higher, since the consideration of time dimension diversifies the peak across the time axis. (Diversity was discussed in section 3.5) where it was described how the diversified demand used for planning is lower than the sum of all the peak demands.

Figure 72 shows the normalised demand scaling factor from Figure 71 over one day on the left-hand y-axis. The values are normalised between 0 and 1 to the minimum and maximum values. Also shown on the graph is the total current day demand supplied to customers (referred to the right-hand y-axis). This is expressed on an inverted axis in order to compare the curve shape with that of the scaling factor. To be clear the supplied demand sum is the equivalent of the demand at the transformer minus the network losses. The demand axis has been scaled and inverted such that the maximum demand coincides with the minimum scaling factor and the minimum demand coincides with the maximum scaling factor. The larger demands generally correspond with lower scaling demand capacity overhead and vice-versa. However the curve shapes are not totally coincident with one another, but differ in places by up to 15 – 20%. This difference is specific to the network and demand set considered. The graph illustrates that network capacity is not a fixed value and also that there is not a simple relationship between network capacity scaling factor and total network demand.

As mentioned previously the demand scaling factor is not just a function of the demand but also of the network topology and impedances and the location of demands on the network. For example considering a network with a relatively large demand supplied by a weak part of the network, this will likely cause a thermal constraint when the demands are scaled up. This constraint would occur at the peak time of the large demand and would set the network capacity factor. However if the same demand were located on a stronger part of the network the demand could be scaled beyond the previous network capacity factor. The network constraint in the new case may be caused by the same or different demand and may occur at a different point on the network and at a different time.

Another example of this sensitivity is a network with a relatively large demand were supplied at the end of a long feeder. When the demands are scaled up a voltage constraint may occur at a lower scale factor than if the same demand were supplied closer to the primary transformer. The constraint for new case may or may not occur at the same point in the network, could be thermal or voltage and may or may not occur at the same time.

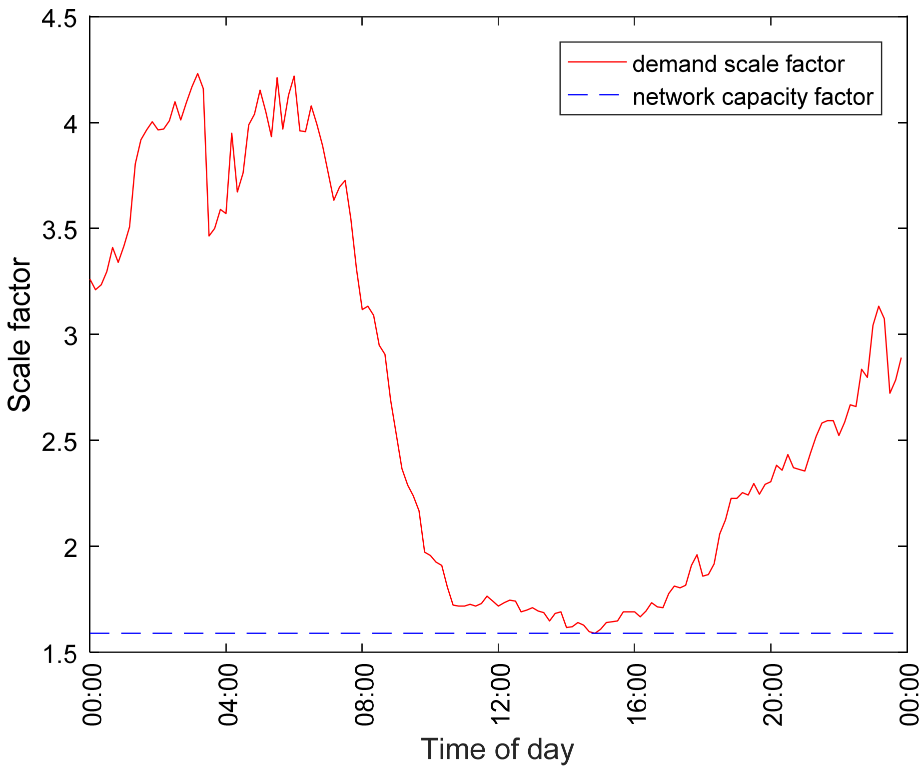


Figure 71 Demand scale factor over a day

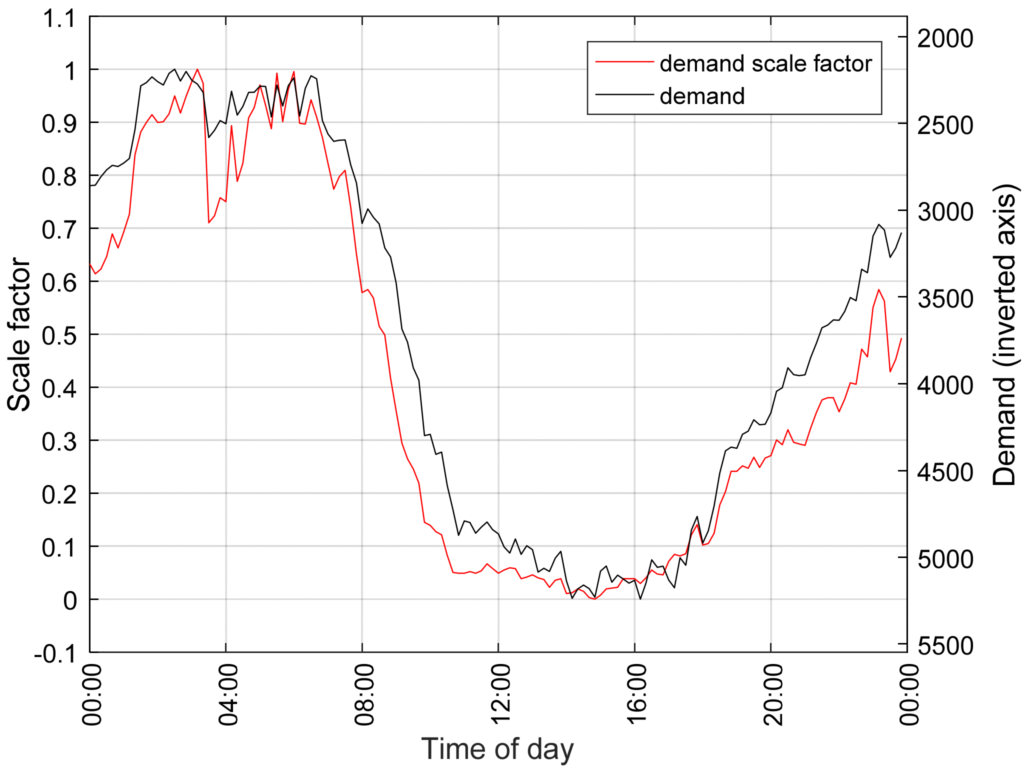


Figure 72 Demand scaling factor related to total electricity demand

10.4. Determining the demand scaling factor for a single set of demand

The previous sections described the demand scaling factor which is a function of time, network and demand parameters and the network capacity factor which the lowest value of demand scaling factor. This section describes the Matlab code that was written to systematically determine these values with demand profiles and network models.

The demand scaling factor is determined using the *networkRunner* object. This contains an object of type *network* and connects to *powerAgent* objects. The *networkRunner* operates over a day of data and calculates the demand scaling factor for each time point during the day.

The *networkRunner* class contains two methods to determine if the network experiences a thermal or voltage constrained within a given period. These are named `runNetworkCheckConstraintOnly` and `runNetworkAllData`. Both methods contain a loop which runs from the start to the end of the input time period testing whether the network would be constrained on any line or busbar (thermally or by voltage) at each time step. The primary transformer is not modelled. The `runNetworkAllData` also stores the time, location and type of constraint for each constraint encountered. This information can be retrieved later using the method `getConstraintsList`. The `runNetworkCheckConstraintOnly` method does not store any constraint information and therefore executes in a shorter period of time.

The demand scaling factor is determined using a binary search method as shown in Figure 6. In this search the initial lower and upper search bounds for the scale factor are set to 0 and infinity. The test value for the scale factor is always set between the lower and upper bounds. If the result of the test value is a constrained network the upper bound is moved to the test value. On the other hand if the test results in an unconstrained network the lower bound is moved to the test value. If the upper bound is at infinity the test value is doubled on each iteration in order to reach the solution efficiently. Once the upper bound has a non-infinite value, the test value is halfway between the lower and upper bounds, meaning that half of the search interval is eliminated at each iteration. The process continues until the search interval is smaller than the desired tolerance of the result. The solution for the scale factor is then within this tolerance. For this work the tolerance was set at 0.005. The initial estimate for demand scaling factor was set at 1.0.

After the scaling factor is determined the network is tested again setting the scaling factor to the upper band and using the `runNetworkAllData` and `getConstraintsList` methods to obtain the time, location and type of the constraint(s). Note that this may return more than one constraint. The constraint associated with the lowest apparent power supplied from the primary is considered to be the network capacity factor.

10.5. Effect of DSR on network capacity

The section 10.2 described how a DSR call on a single load with demand recovery may or may not change the peak demand of that load. In section 10.3 it was seen that the demand scaling factor for a given network and demand set varied with time of day. The experimental work that follows evaluates the network capacity factor. As stated earlier:

$$\text{network capacity factor} = min(\text{demand scaling factor})$$

A DSR call starting at different times of day is modelled and for each DSR call time the demand scaling factor across the whole day is determined. The network capacity for that DSR call time is then evaluated from the demand scaling factor.

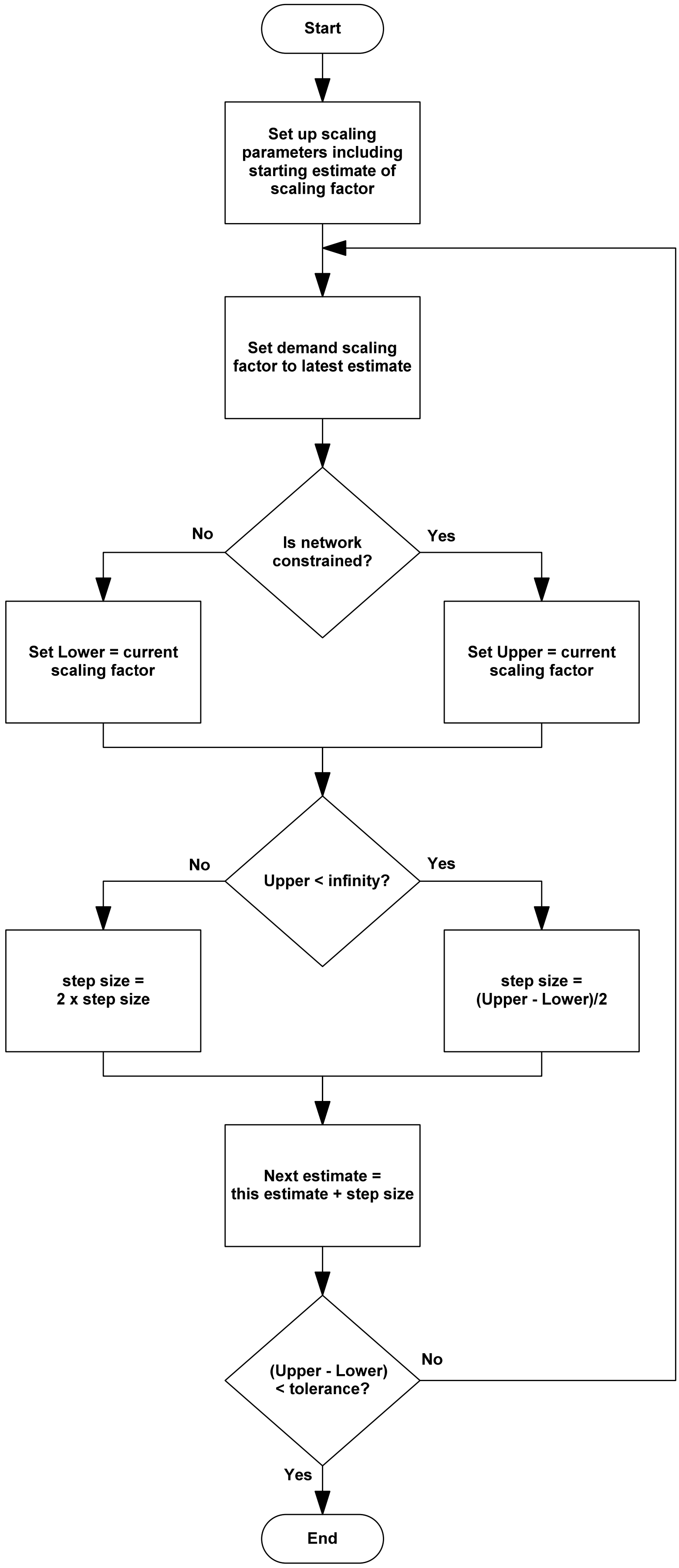


Figure 73 Binary search method for determining the demand scaling factor

This process is repeated for DSR calls at every time point of the day, each time point evaluates a (single) network capacity factor. The resulting data is a set of network capacity factors: one result for each DSR call time.

A scenario is investigated where demands (modelled as 24 hour profiles) at a number of secondary transformers on the network respond to the same DSR service call and the effect this has on the network capacity factor. As has already been stated, the network capacity factor is the lowest value of demand scaling factor (see Figure 71 and section 10.3). This experiment records the network capacity factor for DSR calls starting at different times of the day 24 hours from midnight to midnight. The calls are serviced by network demands that are profiled over 24 hours.

Since the demands respond to the same call their demand reductions are synchronised. If part of this DSR is provided by demand reduction which has demand recovery the demand recovery peaks are also synchronised. This synchronisation reduces the demand diversity at that time which may increase or decrease the peak demand depending on whether the demand reduction or the demand recovery coincides with a period of network congestion. The demand reduction or recovery peaks may have a positive or negative effect on the demand scaling factor at different times of the day. If the effect on demand scaling factor produces a new minimum value, then the network capacity factor also changes.

The algorithm is shown in Figure 74. For each set of DSR parameters a call is modelled at every time point during the day. For each DSR call time the minimum capacity factor is calculated for the whole day and recorded. Then a DSR call at the next time point is modelled and the process is repeated. The result is that for each DSR parameter set a data set is generated which consists of the minimum capacity overhead versus the time of day of DSR call. The modelled day consists of 144 time points each 10 minutes apart.

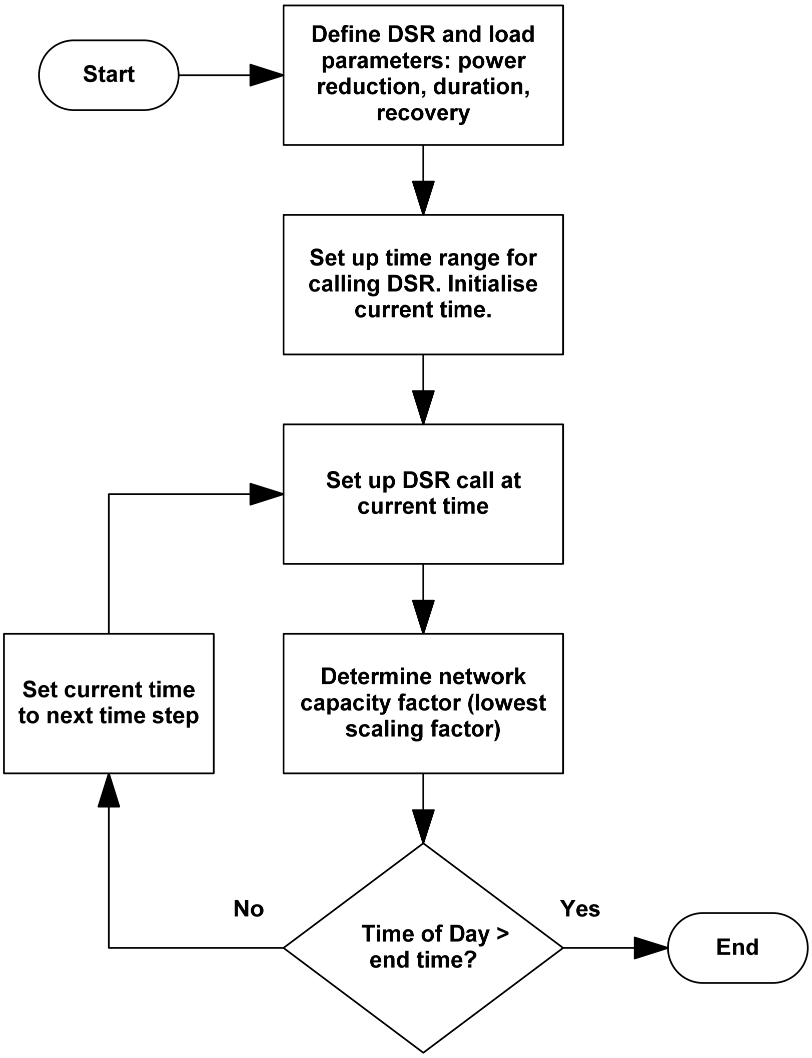


Figure 74 Algorithm for determining the network capacity factor due to DSR call at different times of day

10.6. Determining the parameter space for DSR call modelling

Table 39 shows the limits of the parameter space. The DSR maximum duration was set at 2 hours since a power reduction due to DSR causes a loss of 'utility'. Energy demands with storage are subject to recovery (see section 4.3.2) after DSR. The longer the DSR period the more stored energy is used.

Parameter	Parameter Type	Min	Max	Notes
DSR duration (hours)	Input	0	2	
Max. recovery peak (kW)	Calculated	0	'2xTotal Demand'	
Total DSR power call off (kW)	Input	770	770	Use fixed value
Recovery factor	Input	0	1	

Table 39 Parameter space limits

The maximum demand recovery peak was set at 2 times the total demand on the assumption that the demand is around half the rated value of the load. The recovery peak is limited by the maximum rating of the load.

A fixed value was chosen for the DSR power reduction in order to limit the parameter space to a manageable level. Changing this value would affect the energy (and therefore the peak kW) of the demand recovery and this value is already modified by the demand recovery factor. A total value of 770kW is about 23% of the total 'current day' demand at the primary transformer. This value is apportioned to the individual bus-bars according to their relative real power demand values.

The recovery factor represents the ratio of energy in the recovery to the energy reduction during the DSR. A value of 0 means there is no demand recovery whilst a value of 1 means that all the energy reduction is later recovered. If all the demands with demand recovery are such that they recover 100% of the energy deferred during DSR then this value can be considered as the ratio of demands with demand recovery to the total demands, where 'demands' refers to the sum of the real demands, $\sum_1^n P_{REAL}^n$.

10.6.1. Other Parameter Limits

The maximum DSR energy is $2\text{ hours} \times 770\text{ kW} = 1440\text{ kWh}$

For a recovery factor of 1 the recovery energy is therefore 1440 kWh.

The maximum recovery peak is 2 x total demand. The current total peak real power demand before scaling is 3360 kW and given the assumption that the maximum demand recovery peak is twice the demand this gives a maximum recovery peak of 6720 kW. This gives a minimum allowable recovery time of $\frac{1440}{6720} = 0.21\text{ hours}$. The minimum recovery time was set at 0.25 hours.

Parameter	Parameter Type	Min	Max
DSR Duration (hours)	Input	0	2
Total DSR Power call off (kW)	Input	770	770
Recovery factor	Input	0	1
Recovery Time	Input	0.25	1.0

Table 40 Minimum and maximum input parameter values

Parameter	Values	No. of Values	Total no. of parameters
DSR Duration (hours)	0.5, 1.0, 1.5, 2	4	100
Total DSR Power reduction (kW)	770	1	
Recovery factor	0, 0.1, 0.25, 0.5, 0.75	5	
Recovery time	0.25, 0.3, 0.5, 0.75, 1.0	5	

Table 41 Input parameters for each experiment case

10.7. The network model

The details of the network model were given in section 9.3.3 and the reformulated network diagram and line ratings are reproduced here for convenience in Figure 75 and Table 42. The demands on the secondary transformers are shown in Figures 76 and 77, where a solid line indicates real demand and a dashed line represents reactive demand.

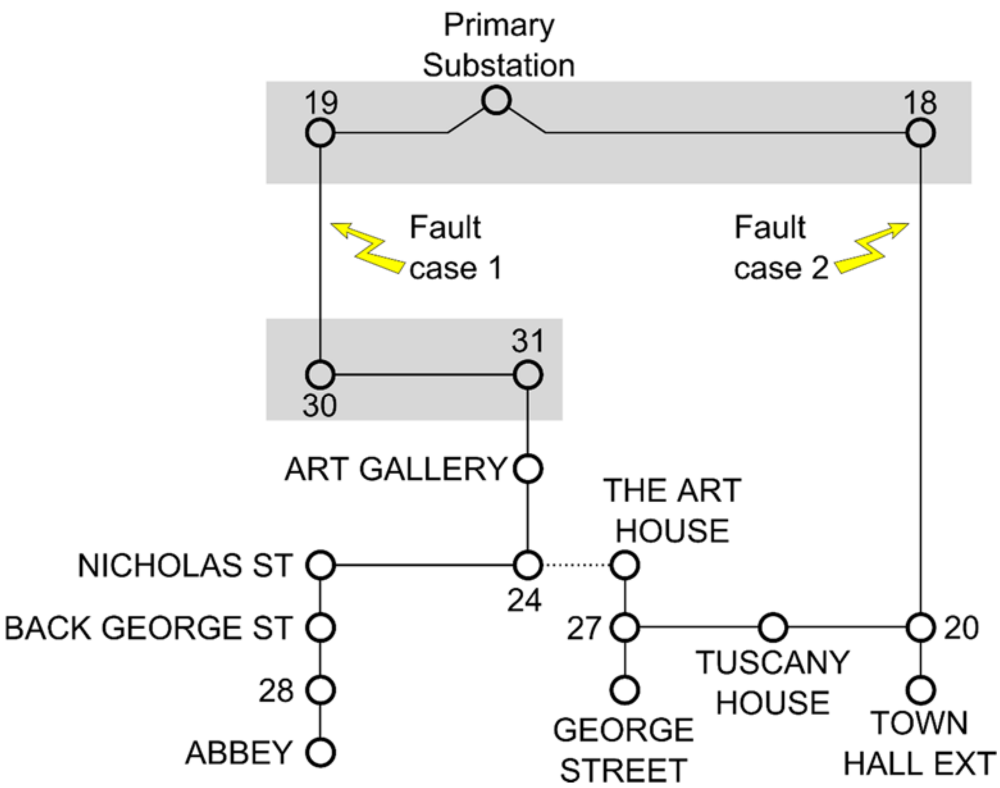


Figure 75 Diagram of network

From	To	MVA	kA
20	TOWN HALL EXTENSION	5.256	0.459781
19	30	5.256	0.459781
ART GALLERY GEORGE ST	31	4.572	0.399946
NICHOLAS ST	24	5.43	0.475002
20	18	5.256	0.459781
THE ART HOUSE	24	7.716	0.674975
THE ART HOUSE	27	7.716	0.674975
24	ART GALLERY GEORGE ST	4.572	0.399946
GEORGE ST	27	5.256	0.459781
TUSCANY HS	20	5.256	0.459781
27	TUSCANY HS	5.256	0.459781
NICHOLAS ST	BACK GEORGE ST	5.43	0.475002
28	ABBEY NATIONAL	5.256	0.459781
BACK GEORGE ST	28	5.256	0.459781

Table 42 Dickinson St network model line ratings

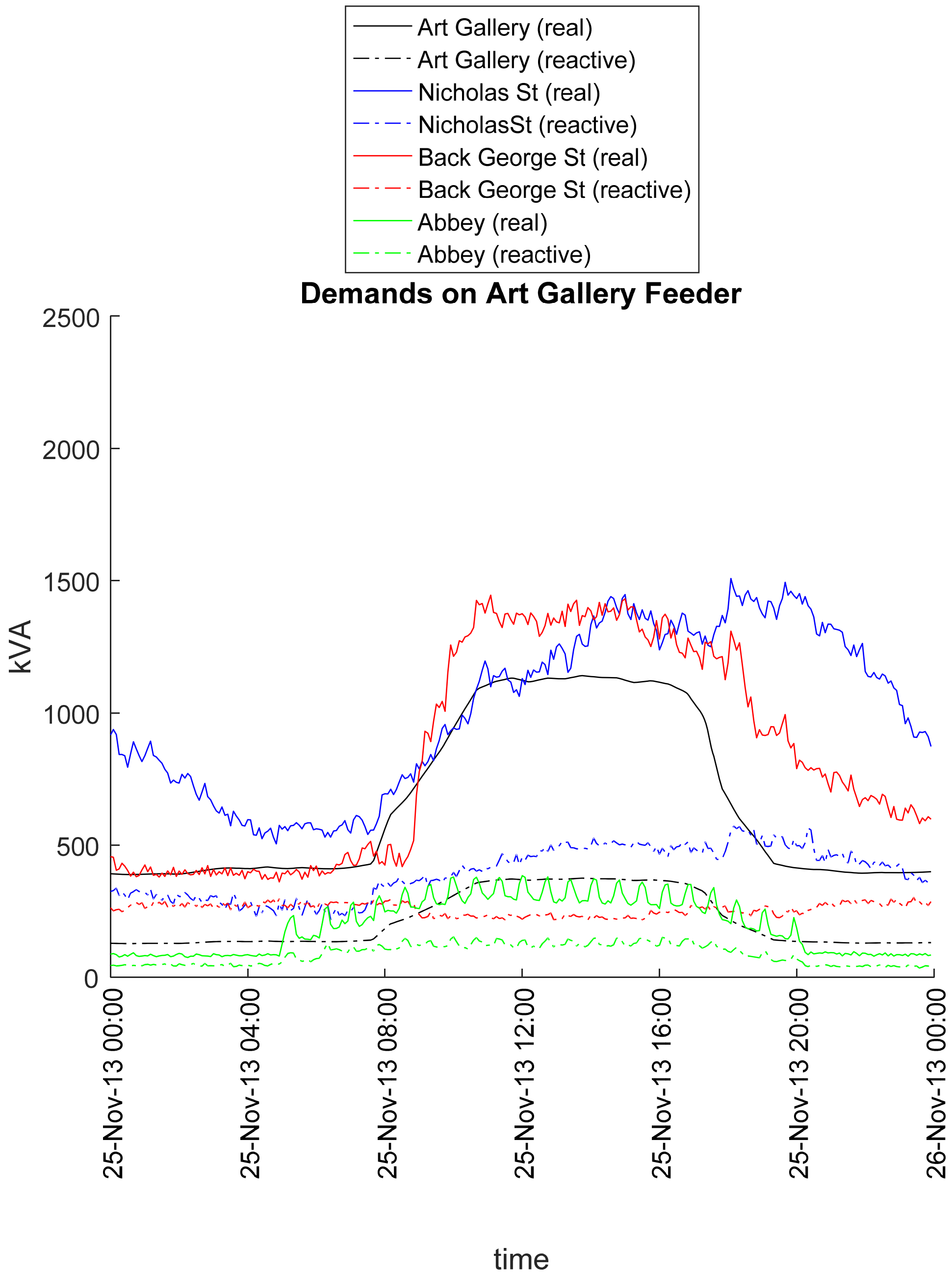


Figure 76 Demands on the Art Gallery Feeder

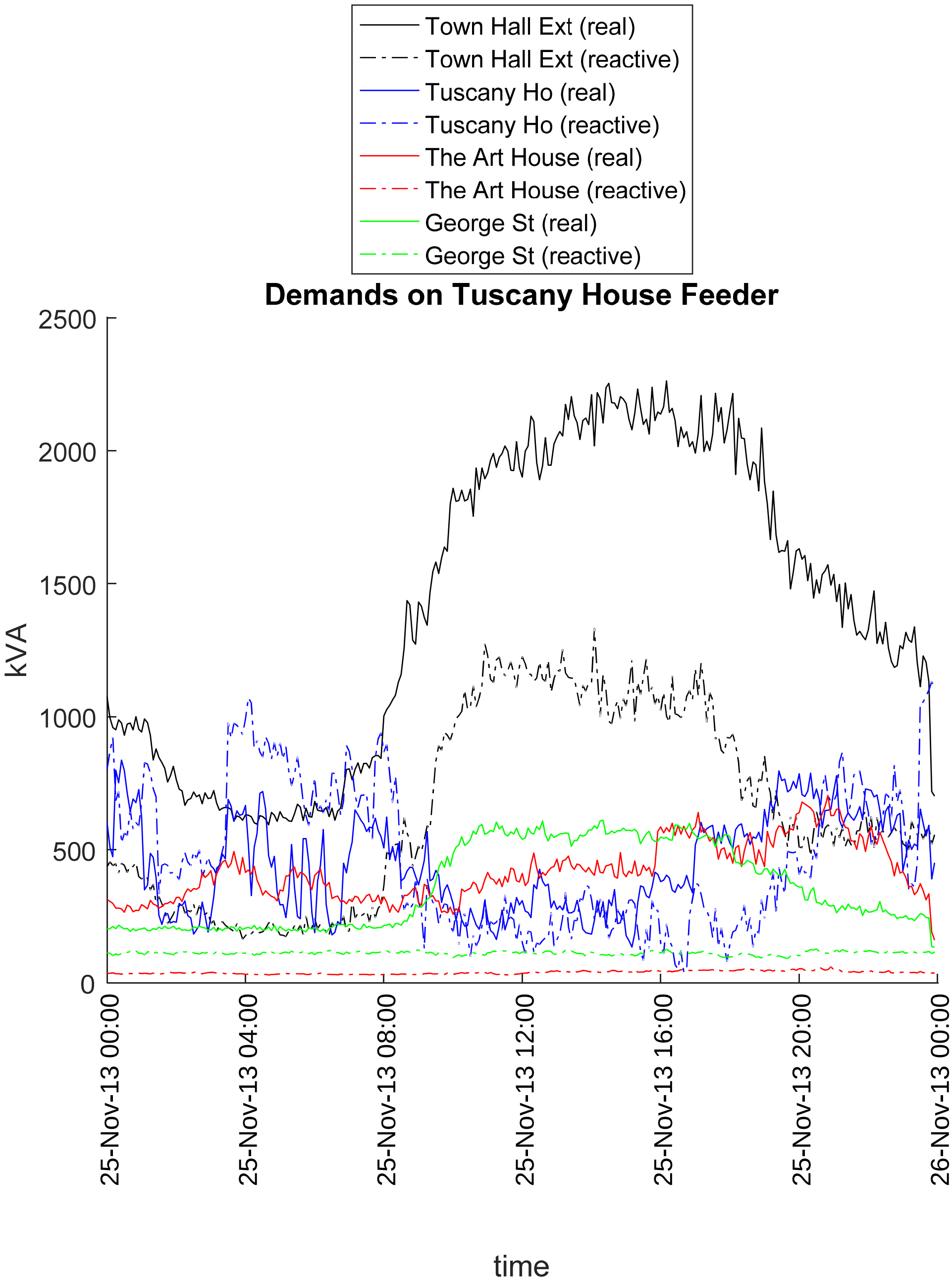


Figure 77 Demands on the Tuscany House Feeder

10.8. Description of experiments and outputs

This section describes the experiments and results. There are six separate experiments which are analysed to produce eight sets of results. There are two sets of results each from Experiment 5 and 6 which are labelled *a* and *b* in Table 43.

The first stage of the work determines the P2/6 capacity by evaluating the network capacity factor for the two extreme n-1 conditions (i.e. a fault on one or other of the two feeders near the primary transformer). This is result 1 in Table 43.

The effect on network capacity when TNO DSR is called on a faulted network is determined for two different fault cases. This is evaluated in experiments 2 and 3.

#	Name	description	Cause of limit
1	P2/6 base case	Determine scale factor for N-1 (two cases, note the least capacity case)	P2/6
2	P2/6 case Fault 1 (on Abbey feeder)	N-1 network TNO DSR calls only	P2/6
3	P2/6 case Fault 2 (on Tusc. Ho. feeder)	N-1 network TNO DSR calls only	P2/6
4	C2C Base Capacity	The base capacity (no TNO DSR) for C2C DSR	Unfaulted network limit
5a	Radial C2C case 1, results set 1	TNO DSR calls	TNO DSR
5b	Radial C2C case 1, results set 2	TNO DSR calls. Network capacity versus peak of demand recovery.	TNO DSR
6a	Radial C2C case 2, results set 1	TNO DSR calls, uneven distribution on DN.	TNO DSR
6b	Radial C2C case 2, results set 2	TNO DSR calls. Network capacity versus peak of demand recovery.	TNO DSR

Table 43 List of experiment result sets

Table 43 shows a list of experiments.

<u>Experiment 1</u> has two fault cases (N-1) on the network without any DSR in order to determine the network capacity. The faults are modelled by opening the line at each feeder leg in turn (nodes 19 to 30 and 20 to 18 on the network diagram shown in Figure 75). In both cases the NOP is closed (node 24 to ART HOUSE) since the NOP would be closed in the faulted condition. The demand scaling factor for each case is determined over the 24 hour period for each case and the lowest value represents the network capacity factor for that fault case. Note there is no DSR modelled for this case. The lowest network capacity factor of the two fault cases is the worst case fault capacity (i.e. the P2/6 capacity). This is the initial firm capacity as described in Table 28. To account for backfeeds from other NOPs that have been closed, this value is increased by 30% to give the base firm capacity. This limit represents the P2/6 capacity (in terms of network capacity factor).

Experiment sets 2 and 3 examine the effect that increased DSR could have on the nominal capacity rating for worst case faults. The DSR is modelled across the distribution network with the total DSR (kW) on the distribution network being apportioned to all the secondary transformers according to their maximum demand as shown in Table 44. For the two cases this means opening the line between nodes 19 to 16 representing a fault on the *Art House/Town Hall Extension* feeder, and opening the line between nodes 20 to 18 which represents a fault on the *Nicholas Street* feeder. In this case the TNO is the only DSR service user.

Experiment 4 determines the C2C radial base capacity. The C2C method gives additional capacity by adding demand which can be curtailed immediately in the case of a fault. Therefore the capacity limit can extend beyond the base firm capacity determined by experiment 1 which is normally required to meet P2/6. In this case there is no DSR provided to the TNO. However, the additional curtailable demand requires contracts with the DNO in order that it can be curtailed when a fault occurs. This is a form of DNO DSR. The DSR does not need to be explicitly modelled since it only comes into effect in the event of a fault and the purpose of this experiment is to determine the network capacity factor for the C2C radial base case (see Table 28).

Experiment 5 produces two sets of results. The first set, 5a, shows the use of DSR called by the TNO on the network capacity factor. Again the DSR is modelled across the distribution network with the total DSR (kW) on the distribution network being apportioned to all the secondary transformers according to their maximum demand, as shown in Table 44. This scenario models TNO DSR but there is implicit DNO DSR in case of a fault, when the C2C demand will be curtailed.

Secondary Transformer	DSR Peak Demand Ratio
BMAG_5min_data	0.1328
NicholasSt	0.1755
TheArtHouse	0.0819
BkGeorgeSt_140130	0.0711
TuscanyHouse	0.0689
BkGeorgeSt	0.1682
ManchesterTownHall	0.2569
AbbeyNat_DSToffset	0.0448

Table 44 Ratio of DSR distributions for radial case 1

Secondary Transformer	DSR Peak Demand Ratio
BMAG_5min_data	0.0000
NicholasSt	0.0000
TheArtHouse	0.1711
BkGeorgeSt_140130	0.1485
TuscanyHouse	0.1439
BkGeorgeSt	0.0000
ManchesterTownHall	0.5366
AbbeyNat_DSToffset	0.0000

Table 45 Ratio of DSR distributions for radial case 2

The second set of results, 5b, uses the same data generated for results 5a. It supposes a situation where the DNO desires to maintain a particular level of network capacity factor perhaps for planned network maintenance. This is the equivalent of saying that the DNO wishes to maintain a level of capacity overhead since it knows that the capacity will decrease due to the planned maintenance and take up some of that overhead.

Experiment 6 repeats the work of experiments 5 but with a different DSR scenario. Here the DSR providers are located on a single feeder at secondary transformers: Town Hall Extension; Tuscany House; George Street; and The Art House. The total DSR kW remains the same but is apportioned between four secondary transformer demands rather than eight, as shown in Table 45.

10.9. Experiment 1: Determining the network capacity factor which meets P2/6

For this experiment there are two cases which test two worst case faults. For case one the line 19:30 is open due to a fault and the NOP (24: THE ART HOUSE) is closed, meaning that the Art Gallery and Abbey National secondary transformers are at the end of the feeder starting at node 18.

For case two the line 20:18 is open due to a fault, the NOP is closed and this means that the TOWN HALL EXT secondary is at the end of the feeder starting at node 19.

Since there is no DSR call for these cases the network capacity factors are constant values. This is because the network will always become constrained at the same location since the demand profiles do not change shape (due to no DSR) and the network will become constrained at the same scaling factor.

The results showed that in case one the scale factor was 0.9961 and in case two it was 0.8594. The cases and results are summarized in Table 46.

Case	Fault point (open)	Time of lowest scale factor	Scale factor at constraint	Constraint Type	Constraint location
One	19:16	14:50	0.9961	Thermal	20 : 18
Two	20:18	14:10	0.8594	Thermal	ART GALLERY: 31

Table 46 Results from experiment one

10.9.1. Discussion of results for experiment one

In case one the thermal constraint occurs near the primary substation. Note that the time of lowest scale factor is different between the two cases but they both occur at times of near peak demand. The worst case is case 2 and this is the *initial firm* value as described in Table 28. Following the C2C analysis [82] (see sections 9.3.1 and 9.3.2) it is assumed that there is an additional 30% capacity available due to network support from other backfeeds giving a network scaling factor for P2/6 of

$$0.8594 \times 1.3 = 1.12$$

This means that in a faulted condition (worst case) it is expected that the network could cope with a linear increase of 1.12 times the current demand. Therefore in the non-faulted condition the capacity should not increase beyond 1.12 times in order to remain P2/6 compliant.

10.10. Experiments 2 and 3: DSR on a faulted distribution network

Experiments 2 and 3 model a fault near to the primary transformer; these are worst case faults. Experiment 2 considers the lesser of the two worst case faults in Table 46. As in the P2/6 case 30% is added to the scale factor to account for network support from back feeds.

10.10.1. Discussion of results for experiment 2

Figure 78 plots the demand scaling factor for experiment 2 (fault case 1). It shows the reduction in capacity for a DSR calls of 2 hours duration giving a total response of 770 kW, with different recovery factors, which represent differing degrees of penetration of DSR with recovery

It can be seen that the capacity factor reduces with increasing recovery factor. This is because a higher energy factor means that a greater proportion of demand has recovery after DSR, and therefore the synchronised peak demand of the recovery is greater.

The P2/6 capacity factor is also shown and it can be seen that for demand recovery factors of 0.5 and 0.75 the capacity is reduced below the P2/6 level.

For demand recovery of zero we might expect to see the network capacity factor increase for part of the day since the DSR reduces demand and there is no capacity penalty from demand recovery peaks, however this is not the case. The reason for this is explained in the following.

A detailed look at the parameters recorded in this experiment reveals that for DSR calls up to 12:10 there are three constraints which occur for scaling factors within the lower and upper bounds (refer to the algorithm in Figure 73). These constraints occur at 14:10, 14:50 and 16:10 (these are all thermal constraints on the line 18:20). A DSR call at 12:20 reduces the demand from 12:20 to 14:10 inclusive, since it is a 2 hour call, thereby avoiding the constraint which would otherwise occur at 14:10. However there are still two constraints at 14:50 and 16:10 which occur within the same network scaling bounds (upper and lower). Therefore the result for network scaling factor does not increase. In fact for a two hour DSR call at any time of the day there will be at least one of the three constraints occurring giving the same result for capacity scaling factor for a DSR call at any time of the day.

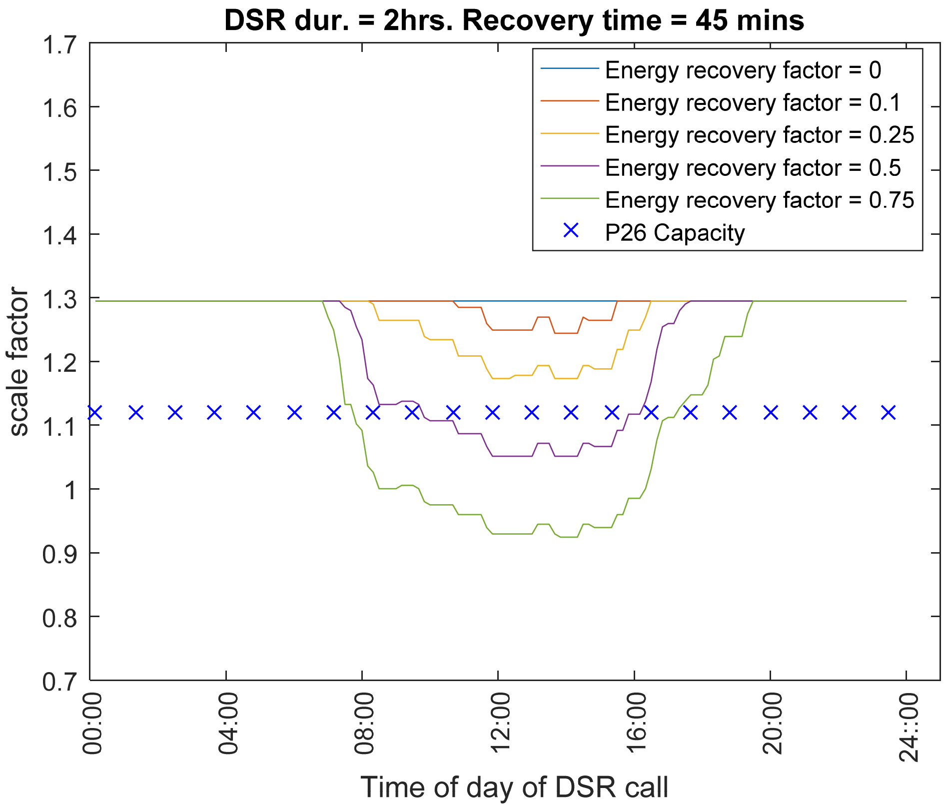


Figure 78 Reduction in network capacity factor due to DSR under Fault Case 1

10.10.2. Discussion of results for experiment 3

Similarly for fault case 2 Figure 79 shows the reduction in capacity for a DSR call of 2 hours duration with different demand recovery factors. As before 30% is added to the scale factor to account for network support from back feeds. The P2/6 capacity factor is also shown and it can be seen that for demand recovery factors the network scaling factor is equal or below this. Any DSR called before 07:00 or after 20:00 does not change the peak demand and so the demand scaling factor remains at the P2/6 value.

Again in this case the scaling factor is never increased at any time even if there is no demand recovery since there are two constraints occurring within the lower and upper bounds of scaling factor. These are thermal constraints that occur at 14:10 and 16:10 on line ART GALLERY : 31. Since they are two hours apart if one of the constraints is avoided due to DSR demand reduction then the other is not. If the DSR duration were slightly longer there would be a short period of time when both constraints were avoided.

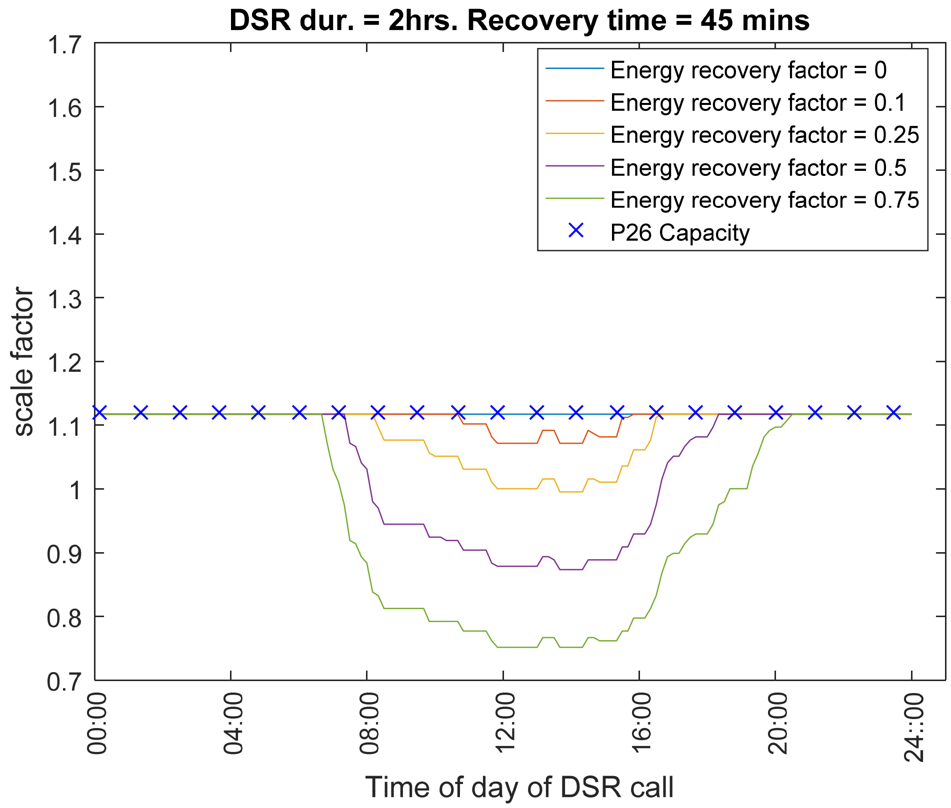


Figure 79 Reduction in network capacity factor due to DSR under Fault Case 2

Analysis of fault case 1 and 2 show that any detriment to DNO network capacity is dependent on the duration of the DSR and the demand profile shapes and magnitudes. The P2/6 rating is effectively reduced at times when there is a fault on either feeder near the primary.

10.11. Experiment 4: Increase in network capacity due to C2C DSR (on a radial network)

The fourth experiment considers the capacity of the distribution network if C2C demand is added. Recall that C2C demand is curtailed immediately on a network fault and therefore the non-fault demand capacity of the network can be increased beyond the standard P2/6 level whilst still remaining P2/6 compliant. Therefore this is a form of distribution network DSR. DSR called by the TSO is not considered here since the reason for this experiment is to establish a baseline. For the sake of clarity: the scaling value is not increased by 30% since there is no support from other network infeeds as the network is not faulted. The network capacity factor is 1.59 as shown in Table 47. This is an increase of 0.47 on the P2/6 value of 1.12 (see section 10.9.1). For this network and demands the maximum demand using the C2C method is 42% above the P2/6 demand.

Case	NOP (open)	Time of lowest scale factor	Scale factor at constraint	Constraint Type	Constraint location
C2C	24:THE ART HOUSE	14:50	1.5898	Thermal	ART GALLERY: 31

Table 47 Capacity scaling factors due to C2C implementation (no TNO DSR)

10.12. Experiment 5

10.12.1. Results 5a

For experiment 5 TNO DSR is considered. Results 5a show how DSR calls starting at different times during the day change the capacity factor. Figure 80 shows the capacity factor against DSR call time for a DSR call duration of 2 hours, with different demand recovery factors with a recovery time of 60 minutes. The capacity is at the C2C base level for DSR calls in the early morning and evening. As with the fault cases in Figure 78 and Figure 79 the capacity factor reduces with increasing demand recovery factor, because a higher demand recovery factor gives a greater recovery demand peak. All the constraints are thermal on the line ART GALLERY:31.

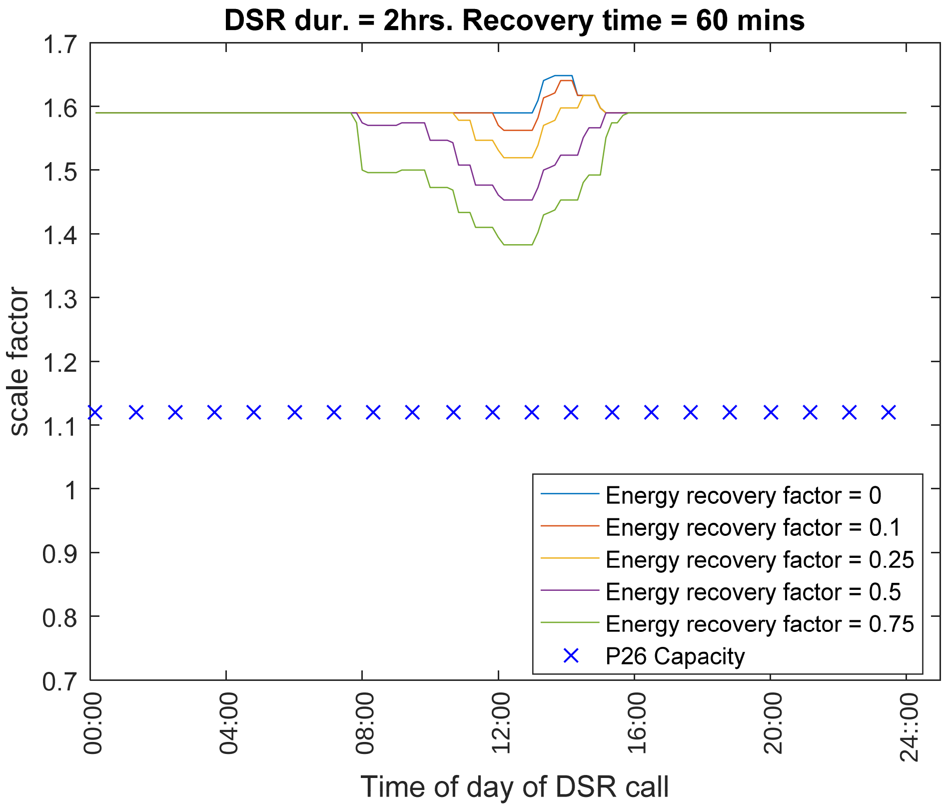


Figure 80 Change in network capacity factor due to a 2 hour DSR call (demand recovery time of 60 mins)

For smaller demand recovery factors there is a time period after 13:00 for which the capacity factor increases. This is because the demand reduction due to DSR is occurring around the time as the constraint which would otherwise occur.

Figures 81, 82, 83 and 84 show the change in capacity factor with time of DSR call, again for a call of 2 hours duration but with recovery times of 45, 30, 18, 15 minutes. The curve for no demand recovery (zero recovery factor) is the same across all the graphs since it is only the DSR duration which is influencing the shape of the curve. As the recovery time becomes shorter (and therefore the peak demand recovery increases) the capacity scaling factor decreases and the range of DSR call times which cause a reduction in capacity becomes wider.

For demand recovery factors of 0.75 or 0.5 the network capacity is close to or less than the P2/6 value if the demand recovery time is 18 minutes or less.

The shape of curves for different recovery factors are similar but not identical. This is most clearly seen in Figure 84.

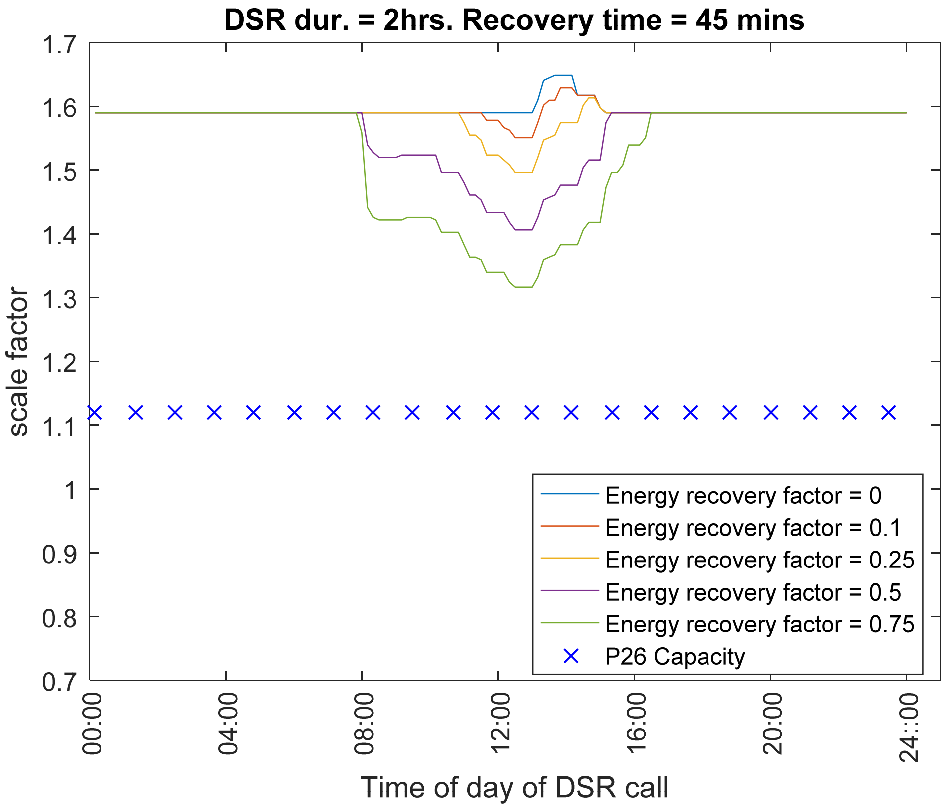


Figure 81 Change in network capacity factor due to 2 hour DSR call (recovery time of 45 mins)

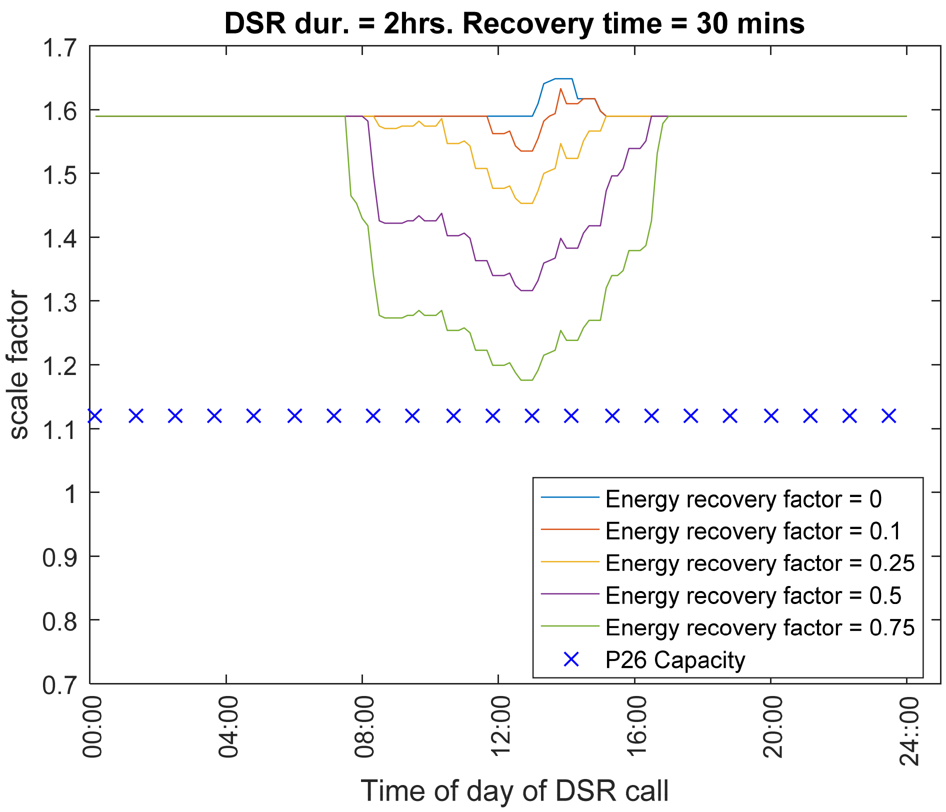


Figure 82 Change in network capacity factor due to 2 hour DSR call (recovery time of 30 mins)

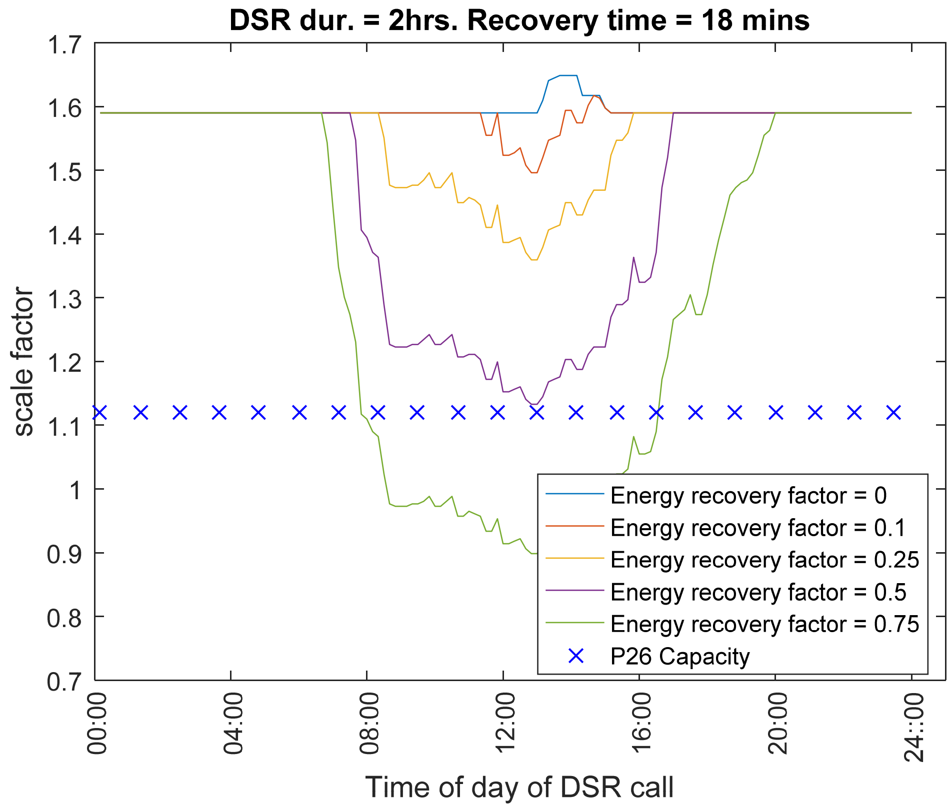


Figure 83 Change in network capacity factor due to 2 hour DSR call (recovery time of 18 mins)

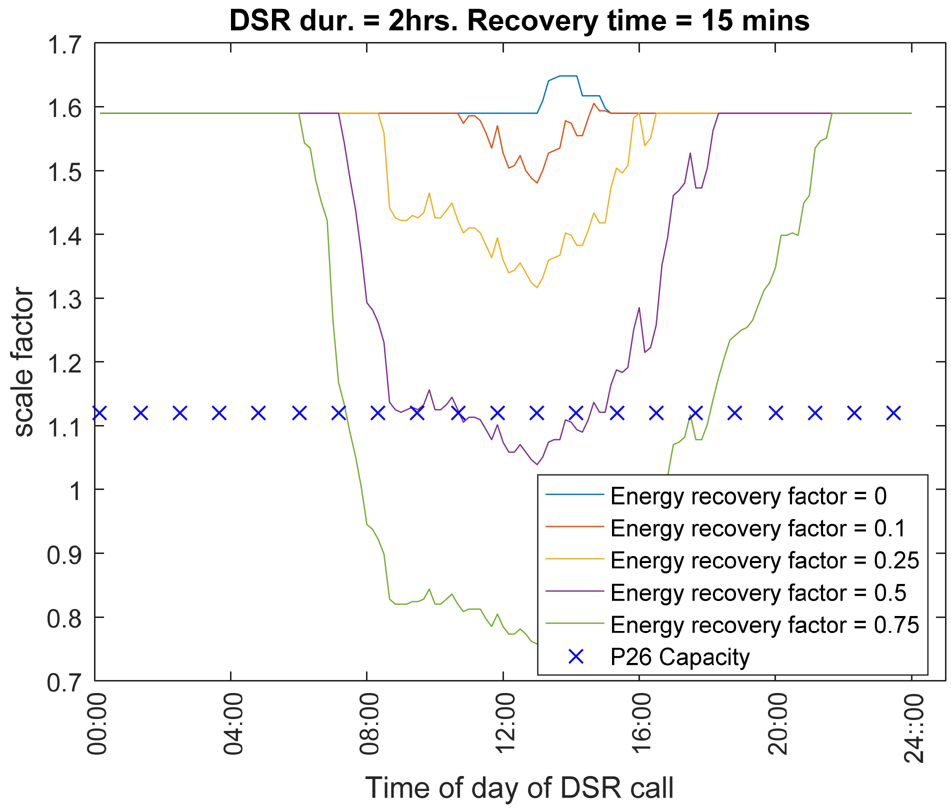


Figure 84 Change in network capacity factor due to 2 hour DSR call (recovery time of 15 mins)

10.12.2. Results 5b

The DNO may want to ensure that it maintains a level of network capacity factor for example to ensure that it does not get too close to the P2/6 limit. These results are from data gathered in experiment 5 and shows how the network capacity factor changes with the total peak of the demand recovery.

The total peak of demand recovery is calculated from the DSR duration, demand recovery factor and recovery time. Note that this peak would be experienced at the primary substation since it is the aggregation of all the demand recovery peaks at the secondary transformers. Recall that the DSR at the secondary transformers are in proportion to the original demand at those transformers and give a total DSR of 770 kW. The DSR is not scaled when the demands are scaled but is fixed at 770 kW.

Figures 85, 86, 87 and 88 show that the relationship between minimum capacity scaling factor and peak demand recovery is approximately linear. The gradient is -0.1782 per MW. The peak recovery axis has been limited to1600 kW since a peak of 1540 kW represents a doubling of the demand reduction of 770 kW.

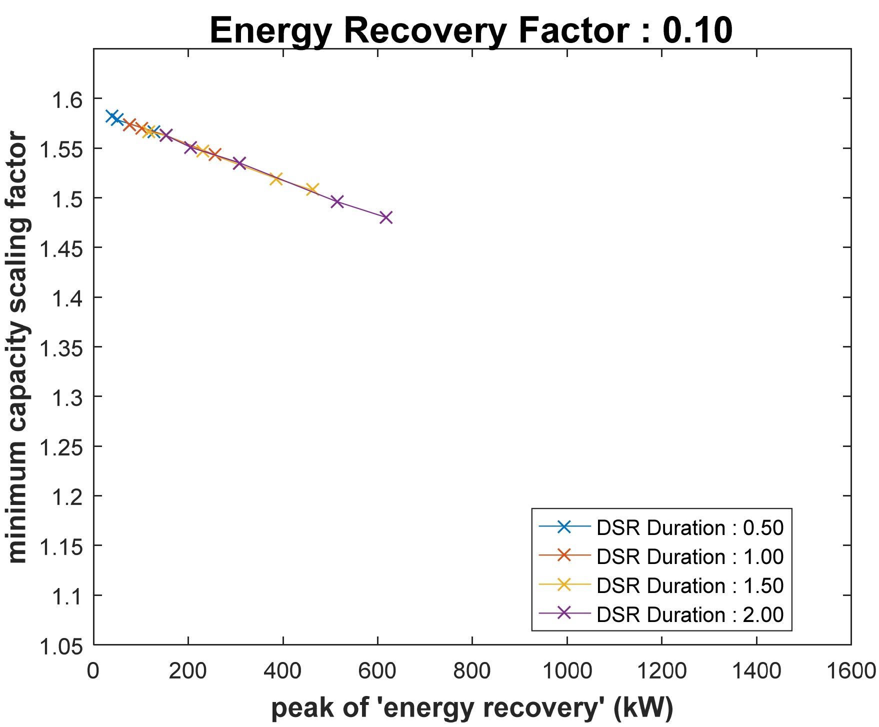


Figure 85 Network capacity scaling factor versus demand recovery peak for demand recovery factor of 0.1

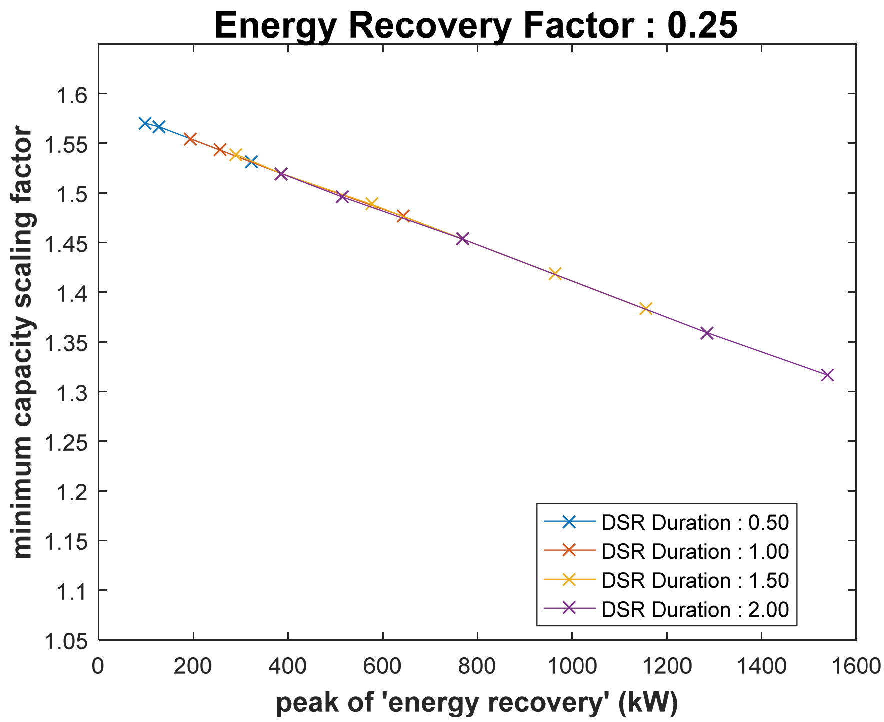


Figure 86 Network capacity scaling factor versus demand recovery peak for demand recovery factor of 0.25

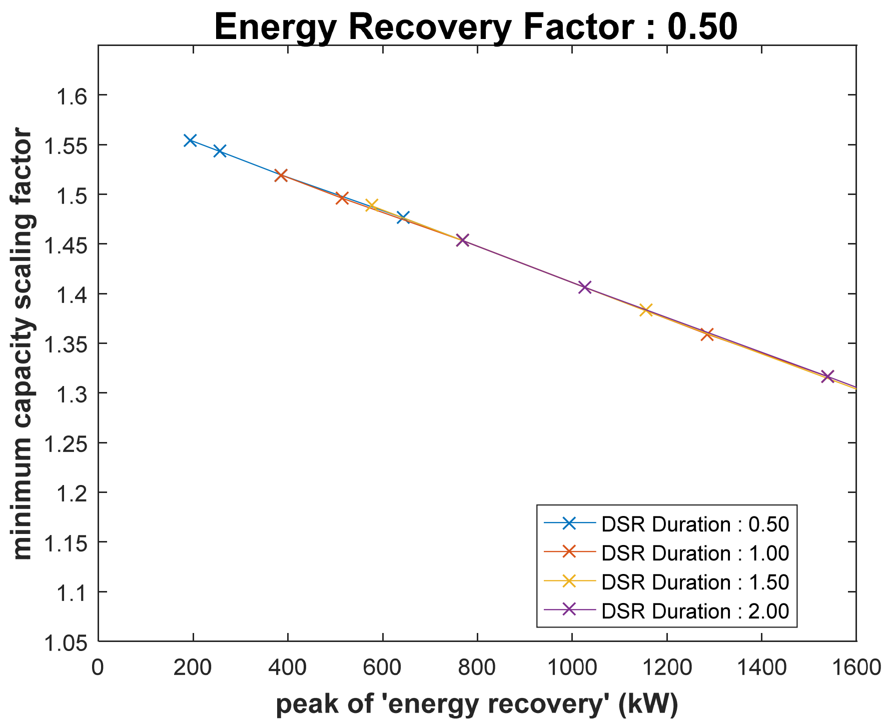


Figure 87 Network capacity scaling factor versus demand recovery peak for demand recovery factor of 0.5

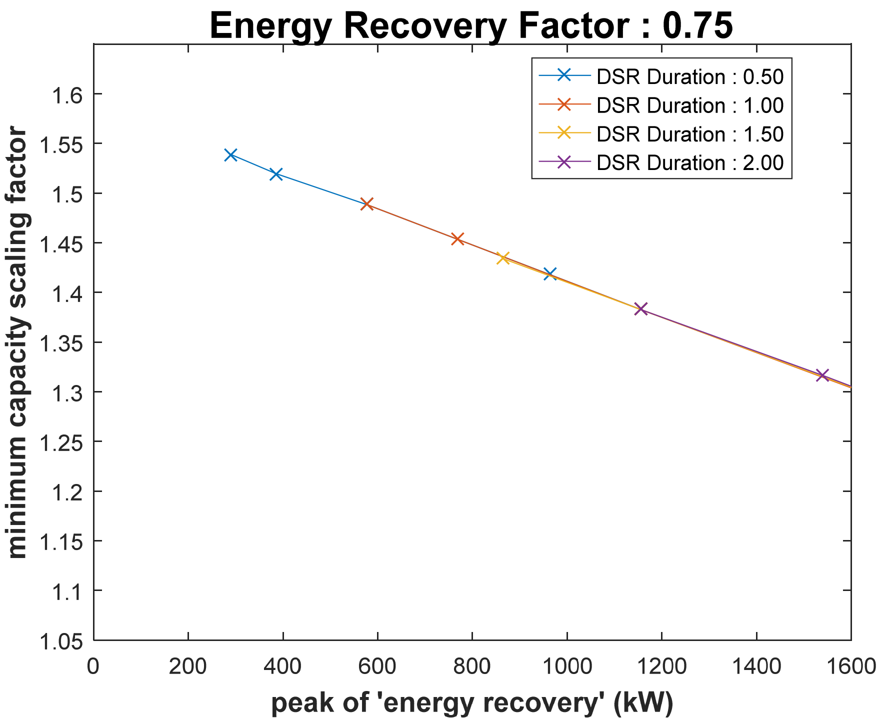


Figure 88 Network capacity scaling factor versus demand recovery peak for demand recovery factor of 0.75

10.13. Experiment 6

Experiment 6 is similar to experiment 5 but the DSR providers are unevenly distributed on a single feeder at secondary transformers: Town Hall Extension; Tuscany House; George Street; and The Art House.

The results for a DSR duration of 2 hours are shown in figures 89, 90, and 91.

10.13.1. Comparing even and uneven distribution of DSR providers for demand recovery factor of 0.75 and recovery time of 60 minutes

For a recovery time of 60 minutes the network capacity is only reduced when the demand recovery factor is 0.75, see Figure 89. The network capacity reduces to 1.54 for about an hour. This impact on network capacity is less compared to the case of evenly distributed DSR which saw capacity factor reduced to around 1.38 and was below 1.50 for about 7 hours (see Figure 80). However for the evenly distributed DSR there was also a time of increased network capacity at the lower demand recovery factors.

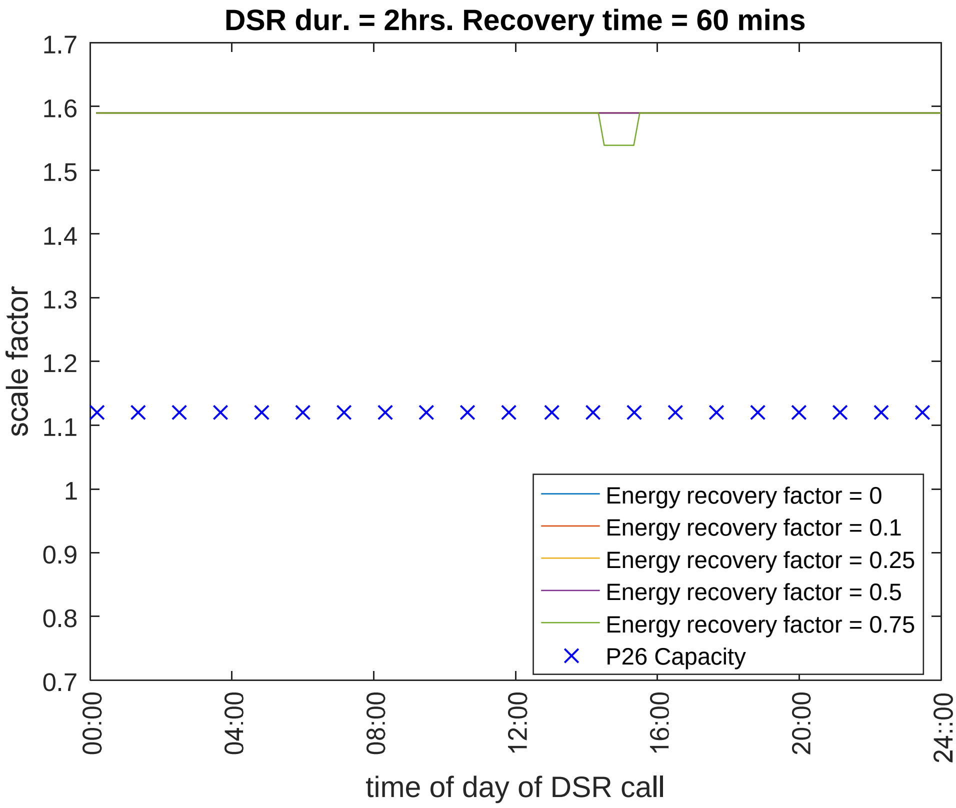


Figure 89 Change in capacity factor due to a 2 hour DSR call (demand recovery time of 60 mins)

10.13.2. Comparing case 1 and case 2 for demand recovery factor of 0.75 and recovery time of 45 minutes

For a recovery time of 45 minutes (see Figure 90) the reduction in network scale factor and duration of the reduction is again smaller when compared to the case for evenly distributed DSR providers (see Figure 81).

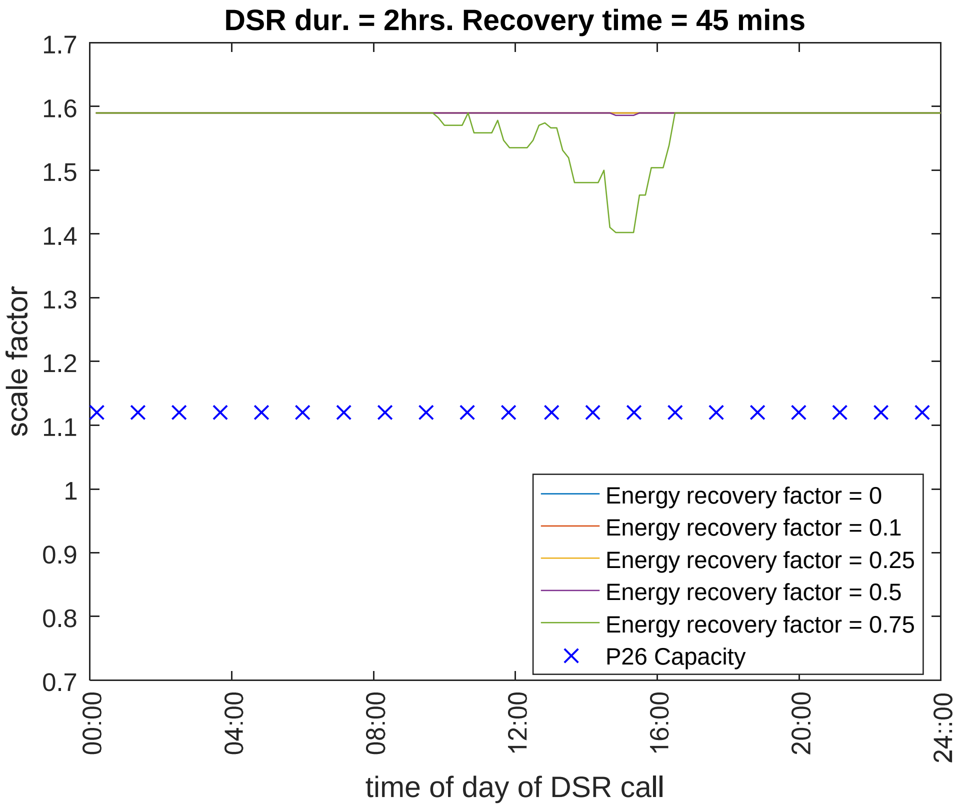


Figure 90 Change in capacity factor due to a 2 hour DSR call (demand recovery time of 45 mins)

10.13.3. Comparing case 1 and case 2 for demand recovery factor of 0.75 and recovery time of 30 minutes

For a recovery time of 30 minutes the worst case scale factor is at 1.13 (almost at the P2/6 rating) for demand recovery factor of 0.75, see Figure 91. the constraint occurs on line 20:18 at 17.10 The scale factor is lower than for the evenly distributed DSR which has worst case scale factor of 1.18 for 0.75 demand recovery (see Figure 82). This is different to the comparisons between the unevenly distributed and the evenly distributed DSR for recovery times of 45 minutes (Figure 90 compared with Figure 81) and 60 minutes (Figure 89 compare with Figure 80). This is summarised in Table 48.

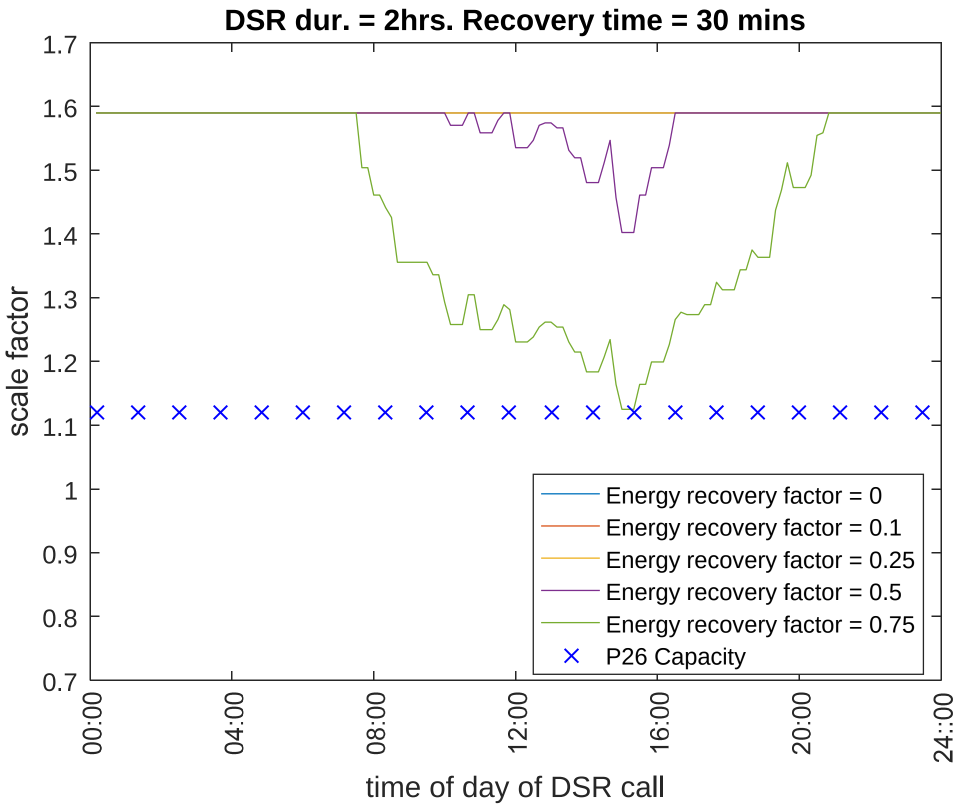


Figure 91 Change in capacity factor due to a 2 hour DSR call (demand recovery time of 30 mins)

	Network Capacity Factor	
Recovery time (minutes)	Expt 5/Case 1 Evenly distributed DSR	Expt6/Case 2 Unevenly distributed DSR
60	1.38	1.54
45	1.32	1.40
30	1.18	1.13

Table 48 Network capacity factor comparison between evenly distributed DSR and unevenly distributed DSR

10.13.4. Comparison of constraint locations

The constraint for the evenly distributed DSR case for an demand recovery factor of 0.75 was on the line ART GALLERY:31 which is on the Art Gallery feeder and has a rating of 4.572 MVA. For the case of unevenly distributed DSR some of the constraints occur on the line ART GALLERY:31 whilst others occur on the line 20:18 which is on the Tuscany House feeder and has a rating of 5.256 MVA.

10.13.5. Results 6b

The results 6b are an analysis of the data from experiment 6 This is the same as the analysis in results 5b but for the radial 2 case.

Figures 92, 93, 94, and 95 show the relationship between minimum capacity scaling factor and peak demand recovery. Unlike for radial case 1 the minimum capacity scaling factor does not change for peak demand recovery of less than 750 kW. In other words no distribution network capacity is lost due to DSR with demand recovery where the recovery is less than 750 kW. However for demand recovery peaks greater than 1300 kW the gradient of the curve is down to -0.3558 per kW which is much greater than for the evenly distributed case.

However, for peaks up to 1600 kW the demand recovery from unevenly distributed DSR is less detrimental to the network capacity since in the worst case the scale factor is about 1.38 (see Figure 94 or 95) compared to 1.3 (see Figure 88).

The reason for the gradient change between lower and higher demand recovery peaks is that for the lower demand recovery factors the constraint is on at ART GALLERY:31 which is on the Abbey feeder, whereas at higher demand recovery factors the network becomes constrained at 18:20 on the Art House feeder which supplies the demands with DSR. At the higher recovery peaks the network capacity factor changes with demand recovery peak.

Figures 93, 94, and 95 show a ‘knee-point’ where the curves change from horizontal to a negative gradient. However, there are several values at which the curves break away from the horizontal at different recovery values. The reason for this is explained in the following. The recovery peak is precisely calculated. However, since the network capacity is obtained via a mathematical convergence, its value is only known within an upper and lower bound. The tolerance of this band is 0.005, which is considered sufficient for network power flow analysis. This tolerance creates a discretization on the y-axis since the set of possible bounding values is governed by a process of halving. This means that values which appear to be the same on the same horizontal line may be slightly different, if they had been evaluated with a different tolerance.

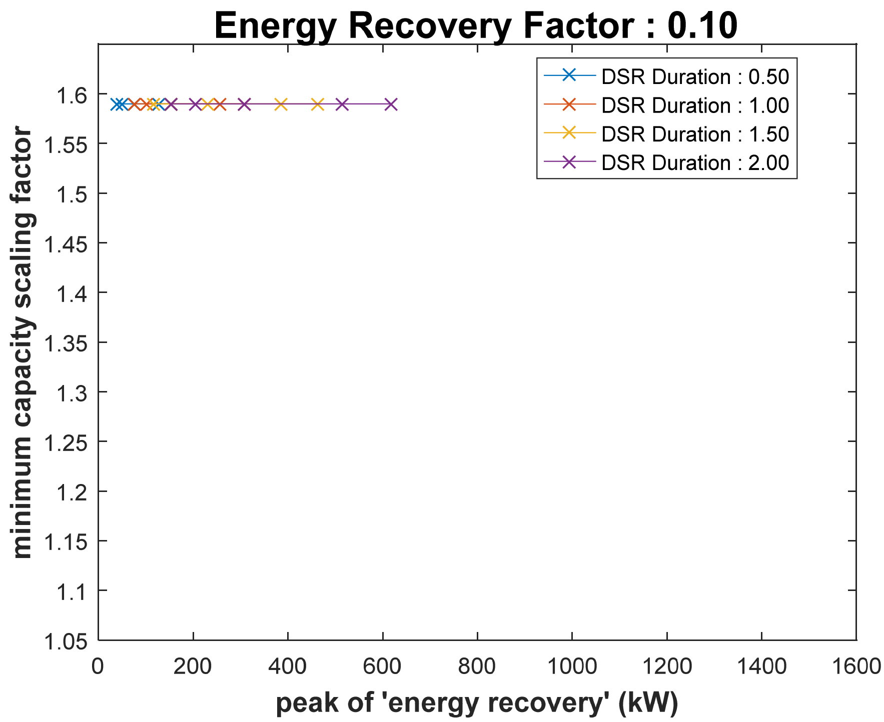


Figure 92 Network capacity scaling factor versus demand recovery peak for demand recovery factor of 0.10

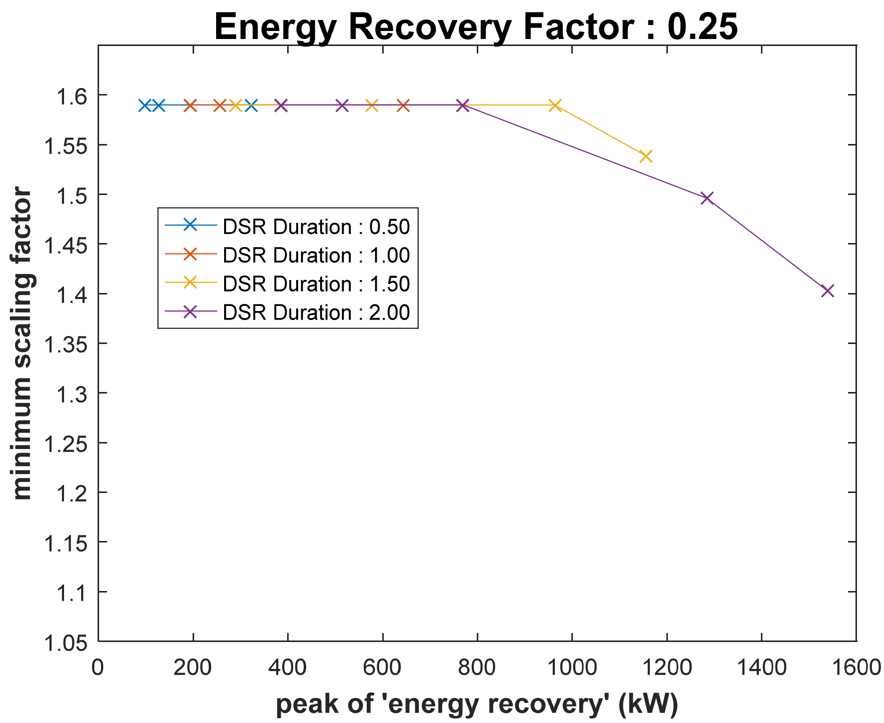


Figure 93 Network capacity scaling factor versus demand recovery peak for demand recovery factor of 0.25

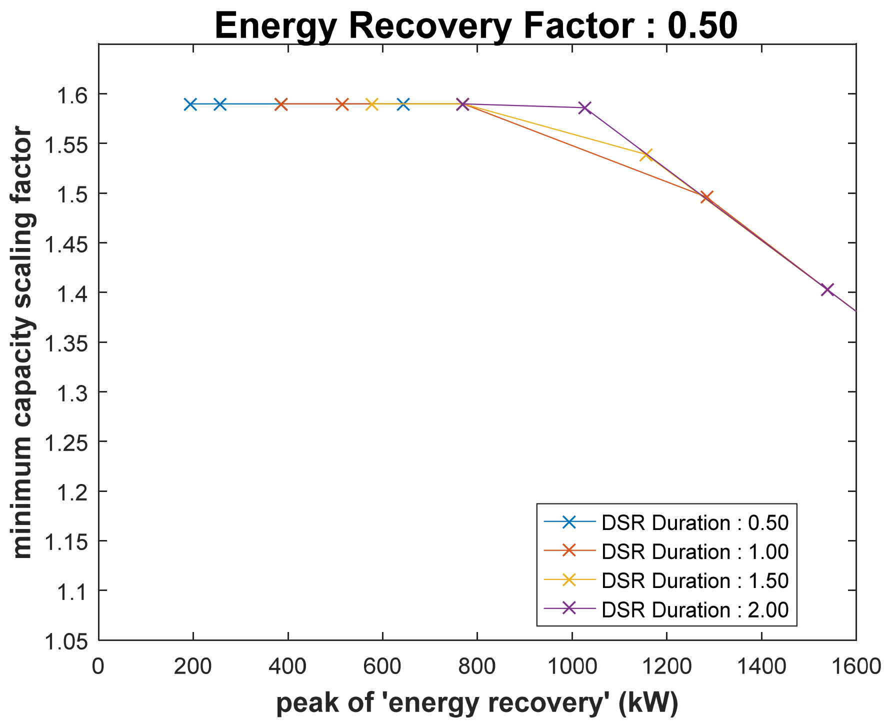


Figure 94 Network capacity scaling factor versus demand recovery peak for demand recovery factor of 0.50

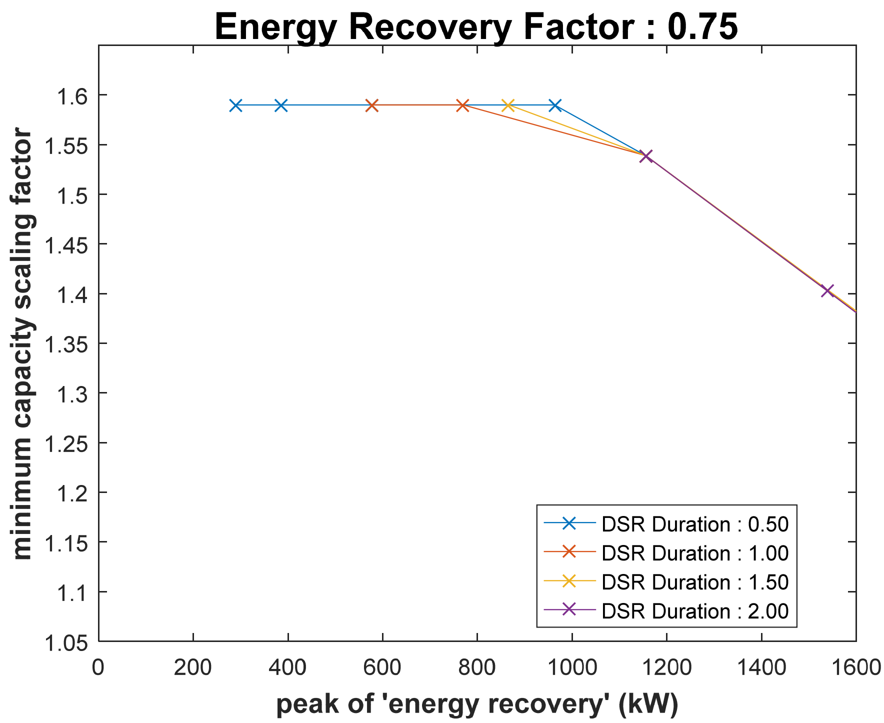


Figure 95 Network capacity factor versus demand recovery peak for a recovery factor of 0.75

10.14. Model assumptions and limitations

As stated previously, as significant assumption of this work, as with the C2C method on which it is based, is that demand grows linearly from current day values. The maximum duration of the DSR was set at two hours. This was based on a assumption that longer durations would cause an unacceptable loss of utility for most loads with storage. The maximum (peak) demand recovery at the primary transformer was set at two times the total demand at the primary. The recovery peak may be limited by the maximum load rating – by setting the value at twice the current demand this implies that on average the demands are at half their maximum rating, which seemed reasonable. The total DSR power reduction (i.e. seen at the primary transformer) was set to a fixed value of 770 kW, which is around 23% of the current demand at the primary.

10.15. Summary

The work in this chapter has shown that transmission network procured DSR may cause a reduction in distribution network capacity depending on the amount of DSR with demand recovery and whether the DSR provision is concentrated at a particular part of the network. Two cases of locational distribution of DSR were explored, evenly distributed and unevenly distributed, each giving the same total amount of demand reduction at the primary transformer.

The impact on the network capacity varies significantly with the time of day of the DSR call and with the locational distribution of DSR providers.

On the faulted networks for a recovery time of 45 minutes and a recovery factor of 0.75, the network factor is reduced from 07:00 to 19:00 for fault case 1 (see Figure 78) and from 07:00 to 20:00 for fault case 2 (see Figure 79). That is to say that for the fault cases the network factor is reduced over a period of 12 – 13 hours for a recovery factor of 0.75. Comparing this to the non-faulted network in Figure 81 with the same recovery time of 45 minutes and same recovery factor of 0.75, the network capacity factor is reduced between 08:00 and 16:00 , which is 8 hours. It is the case with all the curves that the duration of reduced network capacity factor is longer for the faulted network than for the non-faulted network.

The time when the network capacity factor is first reduced is similar for the faulted and non-faulted network, at 07:00 or 08:00 for the recovery factor of 0.75. For the faulted network the increase in time period for which the network capacity factor is reduced occurs later (at 20:00 compared to 16:00 for the non-faulted network).

For the case of evenly distributed DSR with lower recovery factors (Figure 80, 81, 82, 83 and 84) it was seen that there was a time of increased network capacity factor. However, this was not seen for the case of unevenly distributed DSR (Figure 89, 90 and 91). This is because the DSR calls in the evenly distributed DSR case are aiding the weak point of the network by reducing the demand recovery peaks. In the unevenly distributed DSR case there is no DSR on that feeder and therefore the network capacity factor cannot be improved beyond the base case values.

In both the even and unevenly distributed DSR cases for lower values of demand recovery the constraint was thermal on branch Art Gallery : 31 which is on the Abbey feeder. This is true for recovery peaks up to 40 kW in the evenly distributed DSR case and up to 750 kW for the unevenly distributed case. This is a relatively weak point in the network. In the unevenly distributed DSR case all the DSR is provided by demands supplied by The Art House feeder, with none on the Abbey feeder. For recovery peaks up to 750 kW the constraint occurs at Art Gallery : 31 is on the Abbey feeder. This means that the scaling of demands on The Art House Feeder is accommodated by the network inspite of the demand recovery peaks. The network becomes constrained at a weaker branch of the network due to the demands on that feeder (which don't provide DSR). For larger recovery peaks the constraining factor is due to the recovery peaks and occurs on The Art House feeder. The magnitude of the recovery peaks is then the driving factor for the network capacity.

Chapter 11. Conclusions

11.1. Summary of work conducted

11.1.1. Use of standby generation for Triad avoidance

In Chapter 7 it was seen that although the carbon emissions for using the standby generator for Triad avoidance are slightly increased compared to using grid electricity, that the cost of CO_2 emissions is slightly decreased. This is because the charge for CRC is no longer applicable to Diesel fuel. This is an example of a disunity between price and value. It could be argued that this is reasonable, since for small generation the levy would be difficult and costly to monitor and collect. The chapter showed that significant savings could be made by using emergency standby generation to offset Triad charges. Emergency standby generation is an existing building asset with almost zero utilisation. Leveraging profitable use from it is an attractive proposition, especially since its Triad running hours could substitute for maintenance running. The costs in the study did not include the capital cost of grid connection due to lack of information, but a graph of cumulative saving against time was included to enable an estimate of payback to be given when the unmodelled costs were known. Once grid connected it could also be used to participate in DSR services, perhaps via an aggregator, which would improve the business case for grid connection.

The chapter also assessed annual costs and found that Triad made up 5% of the annual bill, DUoS charges made up 19% and the cost of CRC was 7%, for the case presented. This does not include fixed bill costs. The annual savings on the Triad cost are around 26 – 39 % if two or three Triads are correctly predicted and this amounts to 1 – 2 % of the annual bill for the case investigated. The cost of Triad is increasing year on year.

11.1.2. STOR Triad coincidence

Chapter 8 investigated the probabilities and cost benefit spreads of STOR provision having an impact on Triad periods, due to demand reduction where the load is subject to demand. The probability of the total Triad demand decreasing ranged from 1.5 % to 4 % depending on the STOR duration and demand recovery time. Increased STOR duration and decreased demand recovery results in a higher probability of increased Triad demand. The probability of the total Triad demand increasing ranged from 0 to 1.6 %. There is zero probability of increased Triad for STOR durations of 1.5 hours or longer. In general an increased STOR duration and decreased recovery time results in a higher probability of increased Triad demand. However there is an exception to this general trend for STOR calls less than 0.3 hours and a recovery time of 10 minutes. The reason for this is to do with the amount of time for which it is possible that a STOR call results in a peak during the Triad period, as well as the fact that the short duration of the recovery makes the change in recovery peak more sensitive to the STOR duration. This is explained in section 8.6.1.2.

Where the Triad demand is increased, a comparison was made with the Triad demand without STOR for different STOR durations and demand recovery times. The results were expressed as a percentage of the Triad demand when no STOR was provided (see Figure 49) The increase peaked at 0.095 % and was 0 % at minimum. Shorter recovery times resulted in higher probability. The same analysis was made for the cases when the Triad demand is decreased (see Figure 44). The level of relative decreased Triad ranged from almost 0 to - 0.38 % of the Triad demand without STOR provision.

There is a small chance of negative total cost benefit from providing STOR using demand that exhibits demand recovery behaviour when taking into account any increase in Triad costs. This occurs for STOR calls of between 12 and 50 minutes for recovery times of 10 and 20 minutes. To be clear: this means that the STOR provider incurs a net loss of money by providing the service compared with not providing any DSR.

The chapter ended with a broader discussion on the use of Diesel generation for grid services such as STOR. It was noted that a very small percentage of STOR, less than 0.1 %, is provided by demand reduction.

11.1.3. Distribution network capacity loss due to DSR

Diversity is important for network planning in that demands are assumed to be diverse and this reduces the required asset ratings, and therefore the cost. However, Chapter 10 showed that under certain situations demand peaks may be synchronised. The extent to which this lack of diversity impacts the distribution network depends on the demand profiles in the network, their location, the network topology and the network asset ratings.

The work used a demand scaling factor as a measure of network capacity. This varies through the day, although for planning purposes a measure of the minimum scaling value only is required, which is termed the network capacity factor. The demand scaling factor takes into account network factors (impedances and topology) and demand profiles which are time variant. Therefore, the measure takes account of the demand diversity and the network characteristics that meet the demands. It was illustrated that the demand scaling factor does not have a one to one relationship with the total demand, due to the factors included in the calculation. The network capacity factor was calculated for demand profiles which differ only due to DSR calls at different times of the day.

The work showed that distribution network capacity would be reduced significantly by high penetrations of DSR calls on demands that exhibit recovery. The extent of this is dependent on the duration of the DSR and the demand profile shapes and magnitudes. For a radial network operating a C2C regime it was shown that for a DSR call of 2 hours the capacity may be reduced below or close to the P2/6 compliant capacity. This occurs if more than 50 % of the DSR calls are provided by demand reduction with recovery, where the recovery is 18 minutes or less.

These results show that TSO procured DSR can have significant impacts on the DNO.

It is also possible that DSR provision on the distribution network causes an increase in network capacity although the durations and magnitudes of these features are much less significant than the times of decreased capacity.

This shows that the change in network capacity is highly sensitive to the recovery duration and the penetration of DSR providers that exhibit demand recovery.

The demand recovery peak was calculated so that the relationship between it and the minimum network capacity factor could be analysed (shown in Figures 85 to 88 and Figures 92 to 95). For the case when the DSR providers are distributed evenly across the network, the relationship is approximately linear with a gradient of -0.178 per MW. However considering an uneven distribution of DSR providers the minimum network capacity factor is not reduced for peak recovery factors less than 750 kW. However, thereafter that gradient of the curve is steeper than the case for the evenly distributed DSR at -0.356 per MW. This is because at smaller recovery peak values the constraining factor is associated with the network, not the recovery peaks, on the feeder that does not have any DSR. At higher demand recovery peaks the recovery peak becomes the driving factor for the constraint on the feeder which has the DSR.

This shows that effect of DSR on DNO network capacity is highly sensitive to the location of the DSR provision.

It was seen that with low demand recovery DSR provision could increase the network capacity factor by supporting a weak part of the network. Note that the phrase *weak part of the network* is a shorthand since it is not just about asset rating but also the aggregation of the demands supplied using that asset in conjunction with the other network impedances and demand locations. However, unless there is a very high level of confidence in the repeatability of the level and timing and availability of that DSR the increase in network capacity has little value.

11.2. Contribution to knowledge

The electricity system in the UK is a highly regulated collection of private companies and regulating bodies. An evaluation of the electricity industry was conducted in order to produce diagrams of revenue passing between different agents in the system. This was linked to the regulations that govern the revenues.

A suite of software classes was developed in order to model scenarios on the electricity system. The most important or complex classes have been unit tested, as have many of the smaller ones. The suite of classes can represent and model time varying demand profiles on a network; calculate the bill costs for the demands; model DSR provision including differing demand recovery shapes; and determine the type, time and location of network constraints. This significant piece of work enabled assessments of the impact of DSR (by demand reduction with and without demand recovery) on a distribution network, DSR income and electricity costs. The software suite provided much of the experimental data for this thesis, but the scope of its application is broader than has been demonstrated.

A method for assessing the probability of Triad charges being reduced or increased by participation in STOR with demands that are subject to demand recovery was developed. It was shown that the probability of increased Triad demand ranged from 0 to 1.6 and that the probability of decreased Triad was higher, ranging from 1.5 to 4 % for the parameters considered, based on the assumed number of STOR calls per year. However, there is a small chance that STOR income could be negated by increased Triad charges.

The concept of network capacity lost due to synchronised demand recovery peaks after DSR provision was developed and investigated using the software suite. It was shown that the reduction in network capacity due to synchronised demand recovery is highly sensitive to the recovery duration and the penetration of DSR providers that exhibit demand recovery. It was also shown that the reduction in network capacity so caused by this mechanism is highly sensitive to the location of the DSR provision.

11.3. Discussion

11.3.1. Comparing the use different demand side assets for Triad avoidance

Chapter 7 discussed the use of emergency standby generation for Triad avoidance. Triads are a form of peak pricing whose charges support the maintenance and upgrading of the Transmission network as a part of the TNUoS charges described in section 2.3.2.1 and shown in Figure 3. Triads mark times of system peak and, more importantly, Triad avoidance regimes will be geared toward all times of peak demand, as the Triad periods are not known in advance. Since Triads encourage the reduction of peak demand, they also reduce network technical losses which are proportional to the square of the current. In addition, reduced peak demand brought about by the Triad mechanism may avoid or defer the need for additional generation capacity.

Since a major benefit of the Triad mechanism is the reduction of system losses, the use of a Diesel engine to reduce Triads can be seen, in one sense, as the use of energy to offset a loss of energy.

As seen in Chapter 7 the use of standby generation to offset demand during Triad warnings caused an increase in CO_2 emissions whilst at the same time reducing the cost for those CO_2 emissions. The city of London discourages the use of Diesel standby generation except for emergency, due to the polluting emissions (see section 8.11). For these reasons, (i.e. environment and the risk of regulatory changes which prohibit the use of standby generation for this purpose), it is wise to explore alternatives to Diesel generation.

Some modern buildings do not use a Diesel generator for emergency supply but have an electrical storage system. This could technically be used for Triad avoidance and would not create additional CO_2 emissions (except by way of charge/discharge efficiency), nor use any fossil fuel. However, the building owner may be unwilling to sacrifice battery capacity for this purpose in case any emergency would require this capacity. The battery will have been sized according to its function which is to supply critical power in the event of supply failure from the grid. In the future it may be prudent to look at the case for sizing the battery system for critical power and for providing Triad avoidance and grid services. Note that the use of the battery system for any purpose where the building is still connected to the grid would also require a grid connection and this cost would have to be factored into the business case for sizing the battery for functions other than critical power supply.

The use of demand reduction to offset Triads may not bring the same gains as using a Diesel generator, however, like the use of a battery it does not produce additional environmentally harmful emissions nor does it consume fossil fuel. It was previously noted that the use of a Diesel engine for Triad reduction may be viewed as the use of energy to offset energy loss. The use of demand reduction to avoid Triads, however, may be viewed as the use of reduced or time-shifted energy to offset energy loss. In addition, in contrast to DSR using standby generation or a battery system, DSR by demand reduction does not require a modified network connection: the infrastructure needed to participate are already in place. For the levels of demand reduction that are predictable, this same reduction or time-shifting in energy may help to offset the need for additional generation on the transmission network. Since DSR by demand reduction may result in a reduction in net energy it may lead to energy efficiency gains in a way that the convenience of a Diesel generation does not. However, it is likely that the building owner will take the action that is most financially beneficial.

11.3.2. The carbon efficiency of DSR by demand reduction

DSR by demand reduction could offer a more carbon efficient way to reduce peak demand. There are three possible scenarios:

- The demand reduction takes place and there is no recovery. In this case transmission losses are reduced due to both the reduced peak demand giving reduced thermal losses and the reduced net energy demand.
- The demand reduction takes place and there is recovery but the recovery is outside the time of network peak demand and the recovery does not contribute to the total demand beyond the usual transmission peak. In this case the peak demand is reduced and therefore the losses are reduced. If the demand recovery factor is 100 % the increased demand during will mean that the same net energy was demanded over the day, however, since the DSR contributes to a reduction in peak demand the net transmission losses are less.

- The demand reduction takes place during peak demand and the recovery causes a new peak that is higher than the demand peak would have been without demand reduction. In this case, the kW losses during recovery may exceed the losses that would have been experienced during peak demand if there had not been a demand reduction. The recovery duration is likely to be shorter than the period of the peak meaning that the network energy loss may or may not be greater than the losses experienced if there had not been a demand reduction.

Offsetting peak demand by DR does not produce additional carbon emissions in the first and second cases above. For the third case there may or not be an increase in carbon emissions.

11.3.3. Unique problems associated with DSR by demand reduction

The use of demand reduction for DSR may cause unique problems due to the potential of demands with inherent storage to exhibit a demand recovery peak at the end of the period of demand reduction. The provision of STOR and possible coincidence of the demand recovery period with a Triad period was investigated in Chapter 8. The consequences of this may be severe enough to totally negate any income from STOR provision, although the probability of this happening is low, for example the relative cost benefit for the 1st percentile was -0.13 % at minimum. However, the probability of increased Triad demand is up to 1.6%. If the Triad is increased it not only means a reduction in net income from STOR provision, it also subverts the objective of the Triad mechanism, which is the reduction of demand peak. Whilst there are only three Triads there may be 20 – 30 Triad warnings during which electricity users seek to reduce their demand. The effect that the Triad mechanism has on system peak is therefore greater than peak reduction for the three Triad periods on which the financial incentive is based. Recovery peaks that do not coincide with a Triad period, may still occur at a time of near peak demand and so contribute to the transmission network peak. In aggregate this could both add to the network losses and push the system closer toward a requirement for more generation.

The most obvious solution to problems caused by demand recovery is for the STOR providers to use plant that does not exhibit demand recovery. This could be generation or demand reduction using demands without storage. Using Diesel generation, as previously noted, causes CO_2 emissions and its use is discouraged in the City of London. However, section 8.11 noted a justification for the use of Diesel generation in providing STOR. This is based on the fact that if Diesel generation were not used then Closed Cycle Gas Turbines (CCGTs) would have to be part loaded and this part loading causes inefficient running and leads to a net increase in CO_2. Providing STOR by demand reduction with no energy recovery leads to an energy efficiency, that is to say that there is a net decrease in energy usage, since the curtailed energy is never required. However, this advantage must be balanced by a potential impact on distribution network capacity as discussed below.

11.3.4. DSR calls giving rise to a lack of diversity

The work in Chapter 10 imagines a future where the penetration of DSR on the network is much greater than it is today. DSR called by the SO may have an impact on the distribution network where a significant number of DSR providers are located on the network under the same primary substation. This issue could materialise under increased DSR provision by demand response with loads that show demand recovery. The only way, currently, that the DNO would have visibility of this is from HH demand data that it has for calculating DUoS charges. This is an example of DSR called by the SO which has impacts on the distribution network. It also illustrates that the logical separation of actors in the system may need to become more co-operative in terms of the information they share and the actions that they take.

An unexpected peak in demand caused by a large number of demands with synchronised demand recovery may impact on the balance of supply and demand on the system. This synchronisation is a lack of diversity. This could mean that a call for a balancing mechanism service (e.g. STOR) leads to a synchronised spike in demand. In a future with high levels of DSR by demand reduction this synchronous demand increase could in turn could be a contributing factor to an out of limits frequency on the network.

There are two coupled driving features that result in this effect on distribution network capacity:

1. the magnitude of the sum of the recovery peaks, and
2. the time synchronisation of these peaks

By addressing either of these features the effect of mechanism that causes network capacity reduction can be reduced.

The first feature could possibly be addressed if the magnitude of all the peaks were reduced. Commercial HH electricity users are subject to a capacity charge and the charging regime for this could be modified to discourage peak demands. Traditional HH meters would only give a measure of the average capacity over a HH period but smart meters could provide a greater time resolution. However, a stricter capacity charging regime would only be effective if the recovery peak of an individual electricity user is significantly different to its normal demand. This may be the case if the recovery peak occurs at a time of their own peak consumption. If it does not, then the capacity charge would be ineffectual even though the user is contributing to a distribution network problem. The secondary transformer demands may be diversified with respect to each other, but the recovery peaks lack diversity since they are synchronised. Therefore a stricter capacity charging regime may lack sufficient potency to counteract the problem

Another possible way to reduce the impact of demand recovery on the network capacity would be if the DNO were given the power of veto on DSR procurement from certain locations of its choosing. However, this would discriminate against DSR providers that happen to be in an area of network problems. It could easily be argued that the DNO is preventing them from gaining an income from DSR provision due to the network assets being unsuitable. This measure would also require a change to the network agreement between the DNO and the DSR providers.

A third possible solution would be the introduction of a charge based on the ratio of peak to base load could be introduced which would encourage a move toward flatter demand profiles perhaps through the use of behind the meter storage systems. This could also have two impacts on demand recovery peaks. Firstly, since the recovery peak would increase the total bill cost the electricity users would be incentivised against demand peaks. Secondly if the storage is used to contribute to DSR, then the contribution to DSR from demand reduction may be lower which in turn would mean less demand recovery when a DSR call ends.

A better solution would be to address the second feature above by disrupting the time synchronisation of the recovery peaks. This could be achieved by staggering the end time of DSR calls. It would require that the DSR service caller (i.e. the SO) would have to have information about their DSR providers including their location and the method of their response (embedded generation, electrical energy storage, demand response). The information about DSR providers could be forwarded to the DNO, by the SO, who could then request that certain providers be subject to differing end-of-call times. It is only necessary to separate the end-of-call times for DSR providers in the same part of the DNO network and only for those providers that may exhibit demand recovery. This would have an impact on the equity of opportunity to provide a DSR service, but this impact would be to a much lesser degree than would be the case for a DNO DSR veto system.

11.3.5. DNOs lag behind SO in terms of DSR adoption

The SO has developed a mature set of DSR services over a significant period of time. DNOs traditionally have been asset managers and have not engaged with DSR up until recently. Most of the examples of DNO DSR are from Ofgem funded LCNF projects such as CLNR, *Low Carbon London* (LCL), *Customer Load Active System Services* (CLASS) and *Capacity 2 Customers* (C2C), amongst others. That is to say that the DNOs have not used DSR in a Business as usual (BaU) sense. However, with increased generation connected to the distribution network, DNOs may have to engage more with DSR as an alternative to network asset investment or to manage system constraints.

The Demand Turn Up project referred to in section 5.6 described an attempt at DSR sharing between a TNO and a DNO. The DNO found it difficult to procure DSR in the areas which it was required. This is evidence of a particular characteristic of DSR for DNOs: that it is highly sensitive to network location. In addition to the locational sensitivity of DSR the DNO faces the challenge of having a much smaller pool of network connected resources than the TNO. A further complication may arise in that the distribution network is more complex that the transmission network.

11.3.6. The role of aggregators

There is a better business case for DSR providers if they can operate across different DSR markets. It was noted that STOR is an exclusive service and this is because the SO needs to have confidence in the availability of the DSR. Whilst for STOR the importance of confidence in the availability of DSR may be so high that there is no room for compromise, for other services this should technically be possible. With increased knowledge sharing not just of the demand dynamics and the requirements for DSR but also a marketing of information to potential providers the multiple use of DSR resources can be increased. There is a role for aggregators here as they not only have the specialist knowledge but can also absorb some of the risk by virtue of the fact that they have a diversity of providers. In addition they can insulate the providers from some of the contractual complexity of setting up contracts. The diversity of the DSR providers which they engage increases the availability of their response.

11.4. Recommendations

In order to reduce the prevalence of DSR provision by Diesel generator sets, which have a negative affect on the environment and health, an incentive should be provided for the use of non-carbon emitting sources of DSR. This would add value to demand reduction by putting a value on the cost of emissions. In other words if would make a better connection between value (of reduced emissions) and price. It is recommended that the DSR procurer and provider be financially rewarded. This reward should be ramped up over time in order to provide an encouragement to non-carbon emitting DSR whilst allowing a transition away from Diesel generators which will likely take time. The incentive to the DSR procurer would be provided by Ofgem whilst the incentive to the procurer would be managed by the retailer. Verification of non-carbon emitting DSR may present a technical challenge but could be achieved by linking the DSR control signal to the building energy management system in order to reduce particular demands. This may also encourage building owners to take a greater interest in the energy use of their buildings.

Increased knowledge sharing would improve understanding of how the system, including the actors on the demand side, operates. This knowledge will be required to manage the evolution of the system as it encompasses more renewable generation, embedded generation and demand side actions. This is important as the system the system transitions from a planned-out and static-system approach towards an increasingly dynamic system with greater demand from electrified heating and transport and increased variability due to greater reliance on renewable generation. This paradigm shift is sometimes referred to as *DNO as DSO* (Demand System Operator). The Demand Turn Up project was an example of sharing knowledge and this should be encouraged by Ofgem.

In order to take full advantage of DSR, there will be a need for a more integrated approach between the SO and the DNO in the future in order to maximise the benefits of DSR. The Demand Turn Up project reported that it was difficult for the DNO to source DSR in the locations at which they required it. For the SO location is not significant factor for national energy balancing, however it is significant for transmission constraint management and reactive power control. The DNO faces an additional challenge in procuring DSR since its pool of potential providers is so much smaller than for the SO, since the SO can choose DSR connected to more or less any DNO. It was noted that there would rarely be a conflict between the SO and a DNO in terms of DSR requirement. This is because the nature of the constraints and the required durations for each party are generally different. If the DNO required a service in a particular area then NG could choose the next most economically viable area. It is therefore recommended that the DNO should have first choice of any DSR.

Where the SO is procuring DSR on a DNO network it is recommended that it is required to inform the DNO. The DNO should have the right to insist that the end time of DSR calls be staggered across different providers where the calls could interfere with the DNOs ability to maintain network capacity.

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Appendix A: Description of the ENA P2/6 planning recommendation

12.1. Description of P2/6 planning requirement

The ENA Engineering Recommendation P2/6 is a planning requirement to which DNOs must conform since it is a condition of their network licence. The intention of P2/6 is to ensure the security of supply of the electricity network. Security of supply is defined in terms of the duration of loss of supply for different levels of group demand. A load group may refer to a feeder, a number of feeders a substation or an area of the network [86]. Group demands are split into class of supply levels as shown in Table 49.

Class of Supply	Group Demand Range	Minimum Demand to be Met After	
		First Circuit Outage (n-1)	Second Circuit Outage (n-2)
A	Up to 1MW	In repair time: Group Demand	Nil
B	Over 1MW and up to 12MW	(a) Within 3 hours: Group Demand minus 1MW (b) In repair time: Group Demand	Nil
C	Over 12MW and up to 60MW	(a) Within 15 minutes: Smaller of Group Demand minus 12MW and 2/3 Group Demand (b) Within 3 hours: Group Demand	Nil
D	Over 60MW and up to 300MW	(a) Within 60 seconds: Group Demand minus 20MW (automatically disconnected) (b) Within 3 hours: Group Demand	(c) Within 3 hours (for Group Demand greater than 100MW): Smaller of Group Demand minus 100MW and 1/3 Group Demand (d) Within time to restore arranged outage: Group Demand
E	Over 300MW and up to 1500MW	(a) Within 60 seconds: Group Demand	(b) Within 60 seconds: All customers at 2/3 Group Demand (c) Within time to restore arranged outage: Group Demand
F	Over 1500MW	In accordance with the relevant transmission company licence security standard	

Table 49 Normal levels of security of supply [86]

In order to determine if the network for a given load group is P2/6 compliant it is necessary to first determine the class of supply of that load group. This depends on the *measured demand* and the *latent demand*. The measured demand is defined as the demand attributable to all the network infeeds, excluding generation for the demand group considered. The latent demand is defined as the apparent demand increase if there were no distributed generation. This is equivalent to the export of the distributed generation and any demand masked by the generation (such as self supply). If the distributed generation is less than 5 % of the measured demand, $D_{MEASURED}$, then the latent demand is disregarded, and the group demand is simply:

$$D_{GROUP} = D_{MEASURED}$$

If the distributed generation is greater than 5 % of $D_{MEASURED}$, then the group demand is :

$$D_{GROUP} = D_{MEASURED} + D_{LATENT}$$

where D_{LATENT} is the latent demand

The group demand, $\boldsymbol{D_{GROUP}}$, is used to determine the class of supply, as given in Table 49.

The network capacity for the group is determined. If the network capacity and capacity from load transfers is greater than the group demand then the network supplying that demand group is P2/6 compliant. This is shown in Figure 96. If this is not the case and the class of supply is A, then the network is not compliant. However, if the class of supply is within B to F, the contribution from distributed generation that is greater than 5 % of the group demand can be taken into account. This assesses ride-through capability of the DG, availability (F-factors) and common mode failure. Ride through capability refers to the ability to remain connected to the network in the event of a disturbance. The F-Factor value depends on the technology and number of units of a particular type of generation. The dominance of each type of DG should also be considered. In addition when assessing the contribution of distributed generation to capacity the following factors should also be taken into account:

- Demand at risk
- Distributed generation
- Commercial availability
- Technical availability

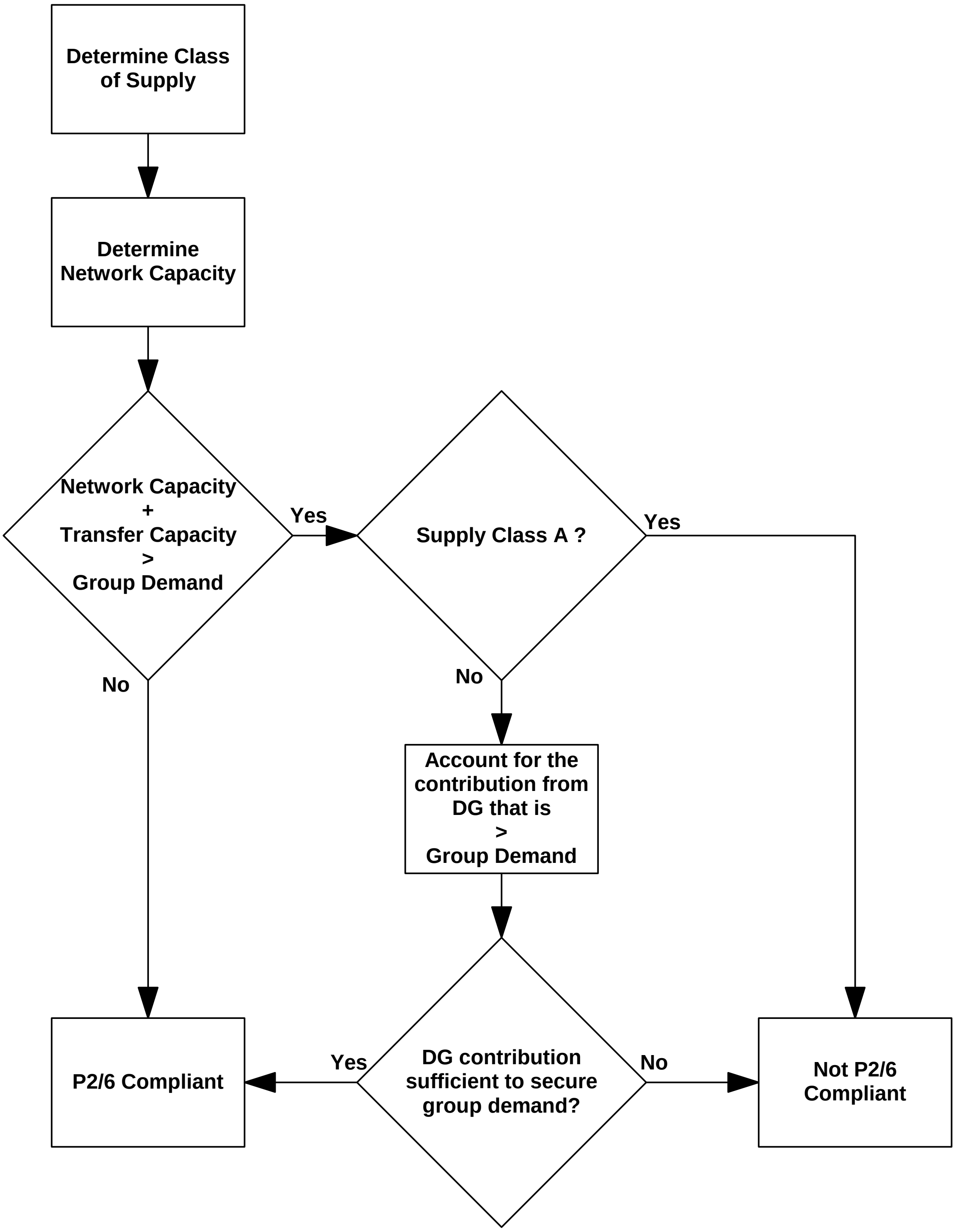


Figure 96 Flowchart for determining P2/6 compliancy

Appendix B: The modelling software suite

13.1. Introduction

In order to help describe and catalogue the software suite a number of approaches have been used, including UML diagrams, method and attribute tables and written descriptions. This appendix first describes some key classes and explains their function in section 13.2. Apart from class descriptions there is a section on how time is represented and accessed in the modelling framework. To aid development unit testing scripts were written for many of the classes. The name ‘unit testing’ comes from the fact that the smallest parts of code are individually and independently tested. In section 13.4 each class is described separately with the following:

- UML Diagram
- List of attributes and methods
- Notes
- Unit testing
- Areas for future development

The list of class attributes and methods is generated automatically using a MATLAB script developed by the author. Table 50 shows the symbols used to represent the visibility of the methods and attributes.

Visibility	
Public	+
Protected	#
Private	-

Table 50 Symbols used to represent visibility level of attributes and methods

13.2. Overview of the main classes

13.2.1. Classes which represent demand

Central to the concept of the software suite is the class *powerAgent* which is a class that can manage demand data including DSR and contains availability and utilisation price data. It can also have a location attribute which defines its place on a network. The *genericPowerAgent* is a child of *powerAgent* and an instance of this class can be interrogated to reveal its expected future demand and known/past demand. These classes are described in more detail in sections 13.4.5 (*powerAgent*) and 13.4.6 (*genericPowerAgent*).

13.2.2. Classes which calculate financial cost

The *elecBill* class when instantiated can take any *powerAgent* as an input and calculate the bill cost for that *powerAgent* based on the demand profiles and on three other objects which have cost data for energy, DUoS and Triad as shown in Figure 97. The *elecBill*, *kwhCost*, *duosCost*, and *triadClass* are described in more detail in sections 13.4.4, 13.4.1 and 13.4.3.

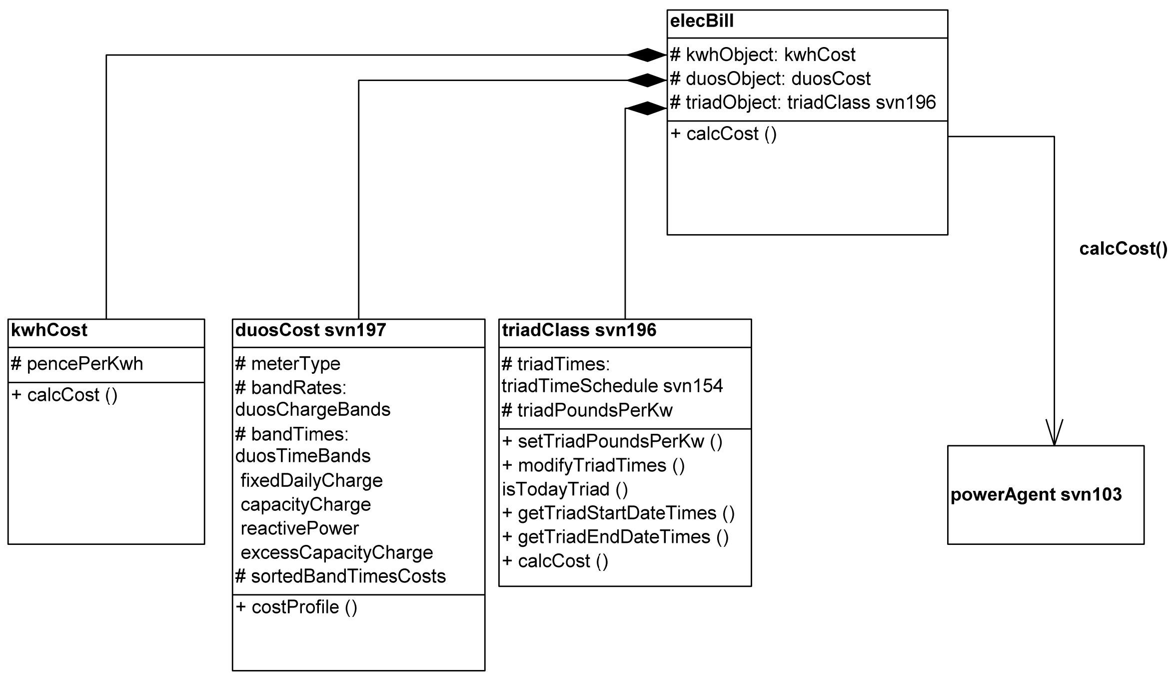


Figure 97 Class diagram for elecBill and associated classes

13.2.3. Classes which model STOR

STOR is a balancing service procured by the system operator (SO), see section 5.3. Referring to Figure 98 the *storSchedTemplate* class holds attributes and methods for stochastic modelling of STOR call dates and times based on the STOR window information and an expected number of calls per year. The *storWindows* class contains data relating to the STOR windows over a given STOR year and can return information such as whether a particular date is a working day (working days include Saturdays for the purposes of STOR) or which STOR season it falls in. It can also return a Boolean value to say whether a particular date and time is within a STOR window.

The *storSchedTemplate* is the parent class for *storScheduleFixedDur* which can be used to generate STOR call information with a given time duration. The classes are described in more detail in sections 13.4.10 and 13.4.11.

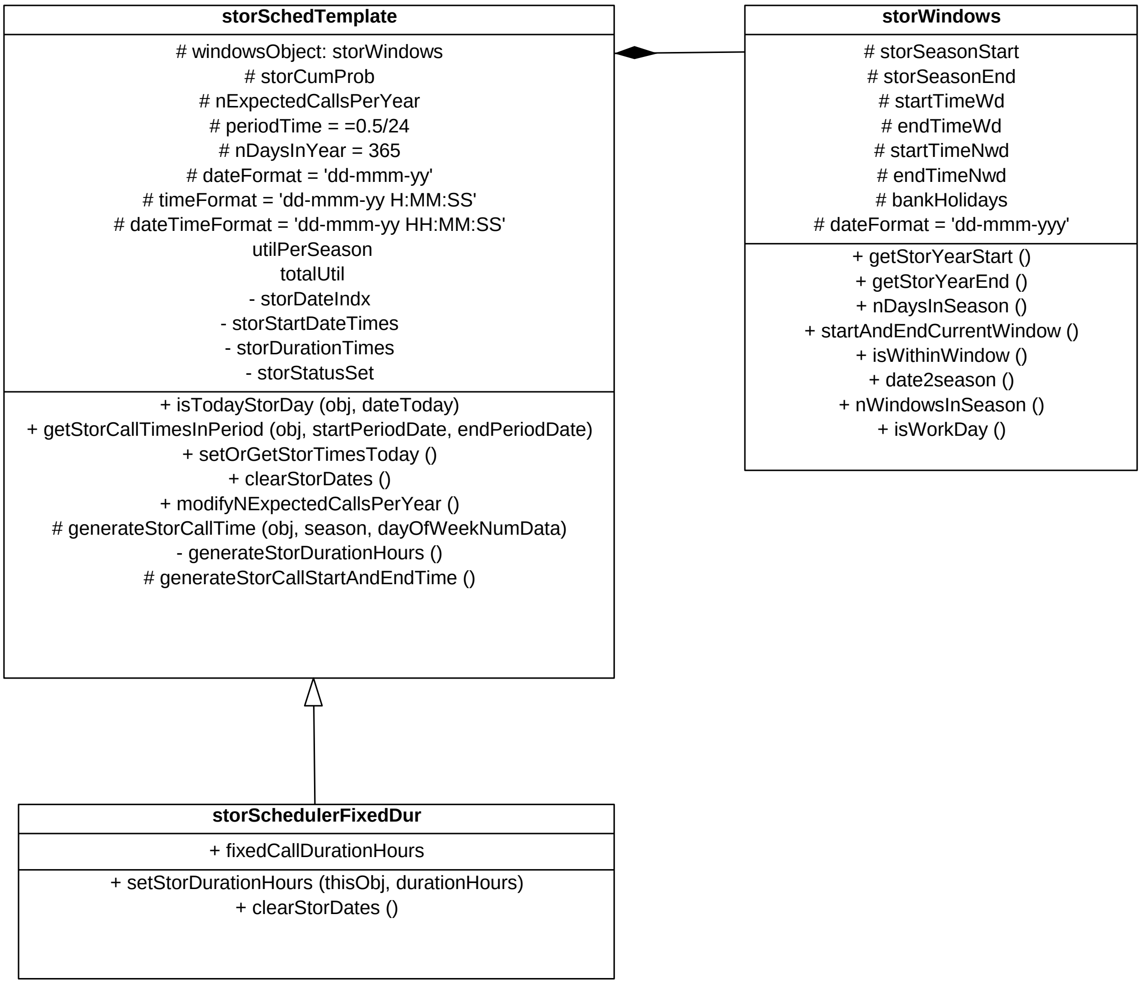


Figure 98 classes for generating STOR call dates and times

13.3. A note on time indexing and the function fFindTimeIndx

For time based data the data consists of the time varying values for each time point and a vector of date/time points. For example for half-hourly demand data there are 48 demand values in a day and a vector of those dates and times. A function was developed to allow access to the index of time data based data without knowledge of the underlying time period between samples. This is of the form:

```
[indxStart, indxEnd] = fFindTimeIndx(timePointsList, startTime,
                                     endTime);
```

Where *endTime* is used for a time range, and is an optional parameter. If it is not included the function only returns *indxEndI.*

An example of this is shown in Figure 99 for half-hourly data. The time 15:30 is stored at index 32. The time 15:30 is stored at index 32. However the interpretation of the data at index 32 should be "the time period between 15:30 to 16:00". In other words the time given at any index refers to the start time for the period (this is indicated by dotted lines).

The way *fFindTimeIndx* works is as follows:

- For the start time it finds the nearest index and returns that as the start index. In the example the nearest time to 15:35 is 15:30, so the index returned is 32.
- For the end time the closest time is found and the time period preceding that is returned. This is because the closest time represents the start of a period and the preceding index represents a period that ends at that same time. In the example the closest time to 16:35 is 16:30 but this index represents a time period starting at 16:30. The time index preceding this represents a period ending at 16:30.and so index 33 is returned.

When interpreting time for a given index that represents a period of time, the interpretation is different depending on whether it is the start or end of a period. If the index represents the start of a period then the time value stored at that index can be used. If the index represents the end of a time period then the time step (i.e. the difference in time between two consecutive indexes) should be added to the value stored at the index. So in the example the end time index is 33 and the time value stored there is 16:00 but 30 minutes must be added to give an end time of 16:30. Note that for demands the time step would normally be less than 30 minutes as the data would normally be at a higher resolution than this.

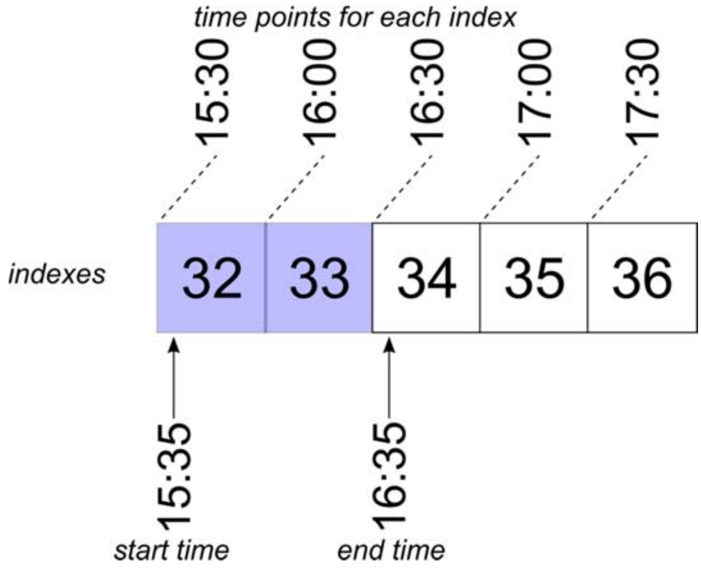


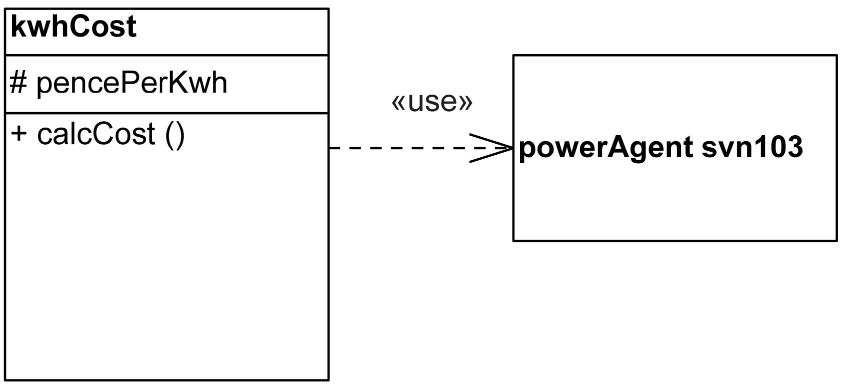
Figure 99 Time indexing example

13.4. Detailed list of classes including testing

This section gives UML diagrams for each component in the software suite and lists the attributes and methods. Where appropriate written descriptions are given to aid understanding. Where unit testing has been undertaken this is briefly described and areas for future development are identified.

13.4.1. kwhCost

This class calculates the cost of energy demand.



kwhCost	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
pencePerKwh	--	kwhCost
METHOD	**INPUTS**	**OUTPUTS**
calcCost	powerAgent	totalCost
	startTime	kWh
	endTime	
kwhCost	pencePerKwh	<constructor>

13.4.1.1. Notes

The method *calcCost* will calculate the energy cost for a given powerAgent between the start and end times

13.4.1.2. Unit testing

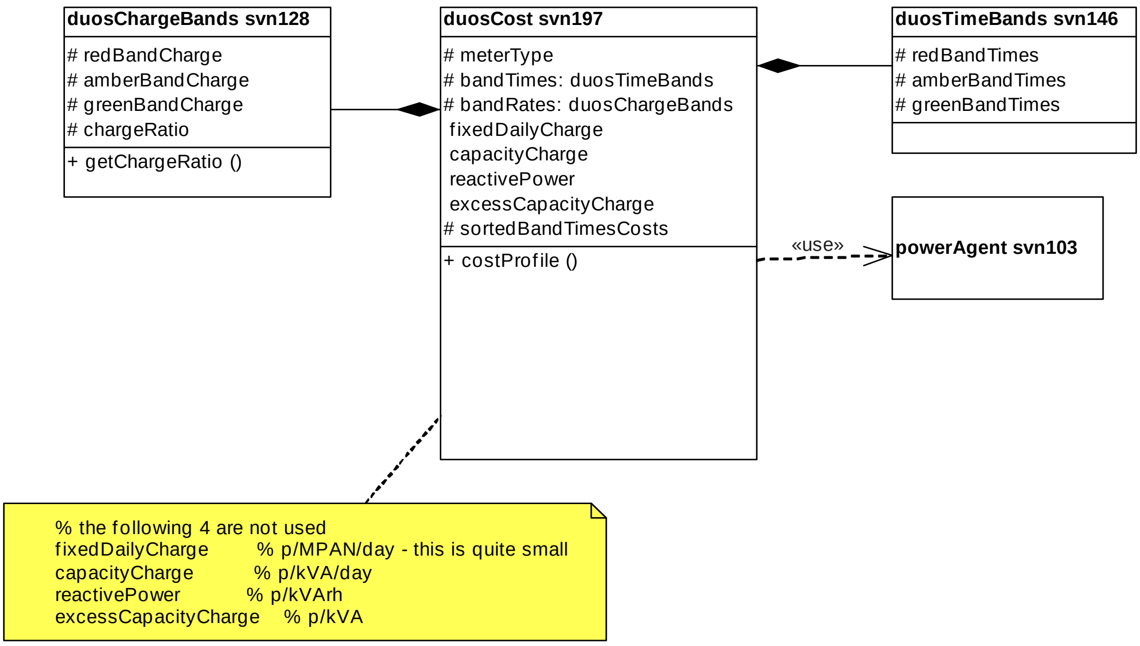
There are two test cases

13.4.1.3. Areas for future development

(none at present)

13.4.2. duosCost

This class calculates the cost for DUoS charges. It requires *duosChargeBand* and *duosTimeBand* objects



duosCost	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
meterType	--	duosCost
bandRates	--	duosCost
bandTimes	--	duosCost
fixedDailyCharge	--	duosCost
capacityCharge	--	duosCost
reactivePower	--	duosCost
excessCapacityCharge	--	duosCost
sortedBandTimesCosts	--	duosCost
METHOD	**INPUTS**	**OUTPUTS**
costProfile	powerAgent	totalCost
	startDay	dayBandsCosts
	endDayInclusive	bandCostsProf
duosCost	duosChargeBands	<constructor>

	bandTimes	
	fixedDailyCharge	
	capacityCharge	
	reactivePower	

duosTimeBands	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
redBandTimes	--	duosTimeBands
amberBandTimes	--	duosTimeBands
greenBandTimes	--	duosTimeBands
METHOD	**INPUTS**	**OUTPUTS**
duosTimeBands	redBandTimes	<constructor>
	amberBandTimes	
	greenBandTimes	

duosChargeBands	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
redBandCharge	--	duosChargeBands
amberBandCharge	--	duosChargeBands
greenBandCharge	--	duosChargeBands
chargeRatio	--	duosChargeBands
METHOD	**INPUTS**	**OUTPUTS**
getChargeRatio		
duosChargeBands	redBandCharge	<constructor>
	amberBandCharge	
	greenBandCharge	

The attribute *chargeRatio* is a [1x3] array which gives the ration of each charge band to the total.

13.4.2.1. Notes

The method *duosCost* requires *duosTimeBands* and *duosChargeBands* in it's construction. A *duosCost* object can be constructed following the steps shown in the example code below:

```
%% create duosTimeBands object (for duosCost object)
% fprintf('\nCreate a duosTimeBands object');
duosTB = duosTimeBands(redBandTimes, amberBandTimes,greenBandTimes);

%% create duosChargeBands object (for duosCost object)
% fprintf('\nCreate a duosChargeBands object');
duosCB      =      duosChargeBands(redBandCharge,      amberBandCharge,
greenBandCharge);

%% create duosCost object
duosBill = duosCost(...
    duosCB,...
    duosTB,...
    fixedDailyCharge,...
    capacityCharge,...
    reactivePower...
    );
```

Whereas some other classes calculate cost based on date and time, the inputs to *costProfile* method must be whole days otherwise an error is returned. The inputs are *startDay* and *endDayInclusive*. In other words for a single day `endDayInclusive = startDay`. This also means that `endDayInclusive = startDay + 1` would mean two whole days.

13.4.2.2. Unit testing

Tests the cost over a three day period

13.4.2.3. Areas for future development

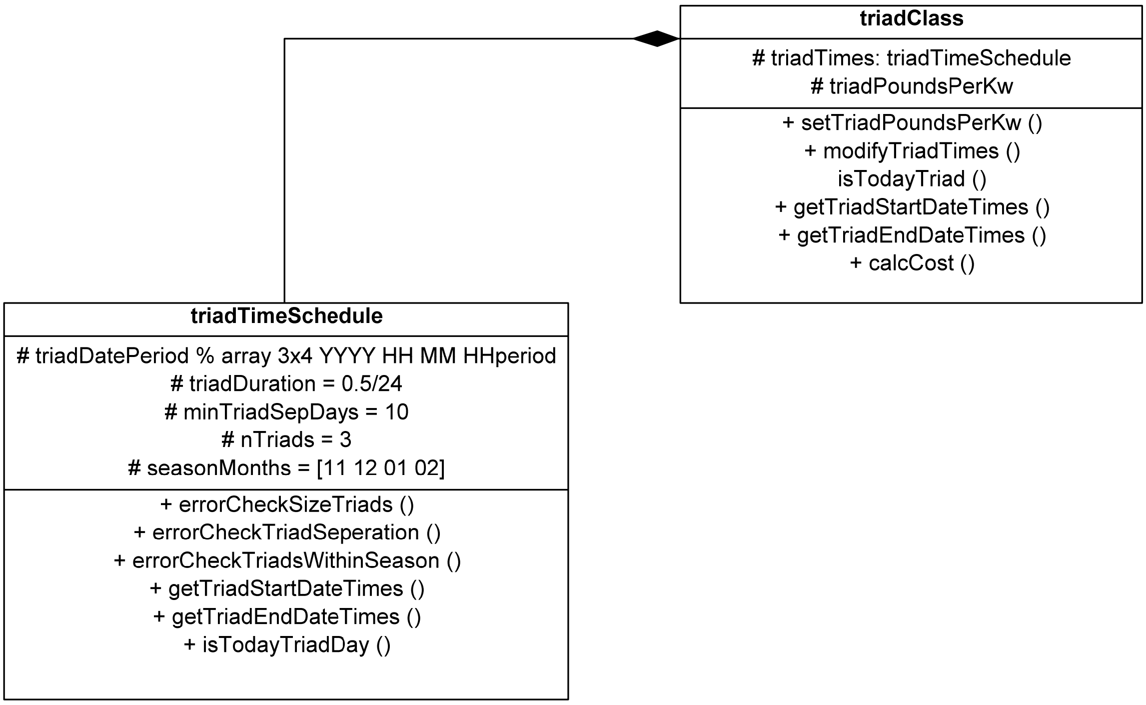
Charges associated with fixed costs are not yet implemented:

```
%fixedDailyTotalCost = nDays * fixedDailyCharge/100;
%capacityCost = nDays * capacityCharge;
%reactivePowerCost = nDays * reactivePower;
%getexcessCapacityCost(excessCapacityCharge);
```

Whereas some other classes calculate cost based on date and time, the inputs to costProfile method must be whole days otherwise an error is returned. The inputs are `startDay` and `endDayInclusive`. In other words for a single day `endDayInclusive = startDay`. This also means that `endDayInclusive = startDay + 1` would mean 2 whole days. There is only a single test in unit testing (cost over 3 days)

13.4.3. Triad

The Triad class is a data class that stores Triad dates and times as well as Triad charge. It can be interrogated to determine if the input date is a Triad day and to calculate the bill cost for the Triads given a powerAgent, start date/time, and end date/time as inputs. The returned cost is only calculated for the Triad times that fall within start and end times. The Triad dates and times are stored in a separate object which can be saved in order to facilitate the creation of *triadClass* objects.



triadClass	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
triadTimes	--	triadClass
triadPoundsPerKw	--	triadClass
METHOD	**INPUTS**	**OUTPUTS**
calcCost	powerAgent	triadCostPounds
	startTime	nTriadsInPeriod
	endTime	
getTriadEndDateTimes	--	triadEndTimes
getTriadStartDateTimes	--	triadStartTimes
isTodayTriad	testDate	todayIsTriad
modifyTriadTimes	newTriadTimes	
setTriadPoundsPerKw	triadPoundsPerKw	
triadClass	triadTimes	<constructor>
	triadPoundsPerKw	

triadTimeSchedule	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
triadsDatePeriod	--	
triadDuration	0.0208	
minTriadSepDays	10	
Triads	3	
seasonMonths	11 12 1 2	
METHOD	**INPUTS**	**OUTPUTS**
isTodayTriadDay	today	triadBool
getTriadEndDateTimes	--	triadEndTimes
getTriadStartDateTimes	--	triadStartTimes
errorCheckTriadsWithinSeason	triadsDatePeriod nTriads seasonMonths	
errorCheckTriadSeperation	nTriads minSepDays triadStartDateTimes	
errorCheckSizeTriads	triadsDatePeriod	
triadTimeSchedule	triadsDatePeriod	<constructor>

13.4.3.1. Notes

The construction of a *triadClass* requires an instance of triadTimeSchedule. Triad dates and periods can be stored in the form shown in Table 51 which is for dates 25-Nov-13, 06-Dec-13, 30-Jan-14 all at period 35.

2013	11	25	35
2013	12	6	35
2014	1	30	35

Table 51 Representation of Triad dates nd periods

13.4.3.2. Unit testing

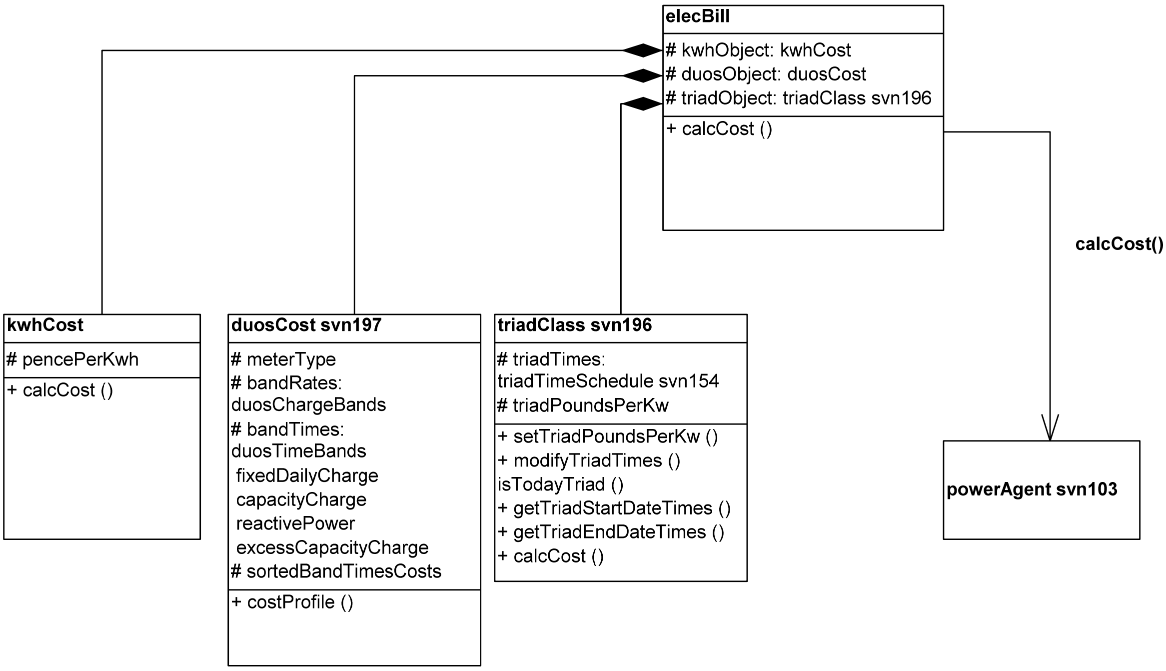
The calcCost method is tested for different periods from one day to a whole year.

13.4.3.3. Areas for future development

Unit testing uses flat/constant demand profile.

13.4.4. elecBill

The *elecBill* class aggregates the cost calculations from other classes in order to provide an easy interface for calulating the whole bill for a *powerAgent*.



elecBill	**superclass name:** handle	
Attribute Name	Default Value	Defining Class
kwhObject	--	elecBill
duosObject	--	elecBill
triadObject	--	elecBill
METHOD	**INPUTS**	**OUTPUTS**
calcCost	powerAgent startDay endDayInclusive	costPounds
elecBill	kwhObject duosObject triadObject	<constructor>

The inputs to calcCost must be whole days to fit with duosCost class The input to calcCost for the end of the time range is called endDayInclusive. To calculate the cost for a single day set startDay = endDayInclusive. If, for example the dates 1st November 2013 and 2nd November 2013 were used this would calculate the bill cost over two days.

In order to use the kwhCost and *triadCost* objects a variable is created (endDayIncTimeOfDay) which adds the time so that the end time is equal to endDayInclusive + 23h 59m 59.99s which is midnight of the end day.

13.4.4.1. Unit testing

The cost for three different time ranges is evaluated: a non-Triad day, a Triad day and a range of days which start on a Triad day and end on the next Triad day

13.4.4.2. Areas for future development

The *calcCost* method only works for input dates which are an integer number of days. If the date s not integer an error is returned stating that it must be a whole number of days. This is because of duosCost class.

13.4.5. powerAgent

As previously stated the *powerAgent* classes manage and modify demand data including DSR. Objects of type *powerAgent* can be located on a network model using the *networklocation* attribute in conjunction with a *powerNetwork* object. Demand reductions are negative values. Flexibity to reduce demand is also a negative value (inputs to method checkFlex and property exptFlex). The class *powerAgent* is a generic class with some abstract methods. Only the child class *genericPowerAgent* should be instantiated.

Attributes for managing DSR

The *powerAgent* class was designed such that it contains expected and actual values for various parameters. The expected values are written into an object of this class but the actual values start off empty. When certain methods are evoked in the class the expected values are copied to the actual values for the given time period (that time period is then conceptually in the past). The motivation for this was that the model might be used to apply an operational decision ahead of time based on an expected flexibility but then that flexibility may change before the operation due to a second operation. Note that a negative flexibility means that demand can be reduced. Demands in *powerAgent* are in kW.

The attributes for demand and flexibility etc. are linked to a column vector date/time information. The time step/resolution of *dateTimes* for different objects does not have to be equal. This allows for *powerAgents* with different data resolutions to be used in the same model.

There are three methods associated with accessing the expected and actual values are:

- *checkFlex*
- *anticipateDsr*
- *activateDsr*

These methods are abstract, meaning that they are defined in child classes. The implementation of the methods is described in section 13.4.6 for the class *genericPowerAgent*.

In Matpower each bus is defined by a number but the *powerNetwork* class uses a custom data-type called *networkLocation* to define each bus and a pair of *networkLocation* to define a branch. This data-type includes the Matpower bus number and a text name and (optional) description. A list of network locations is kept in property busLocationList which is a row vector (1xn) of networklocations.

13.4.5.1. Unit testing

The class *powerAgent* cannot be instantiated. Unit testing is carried out on the child class *genericPowerAgent*.

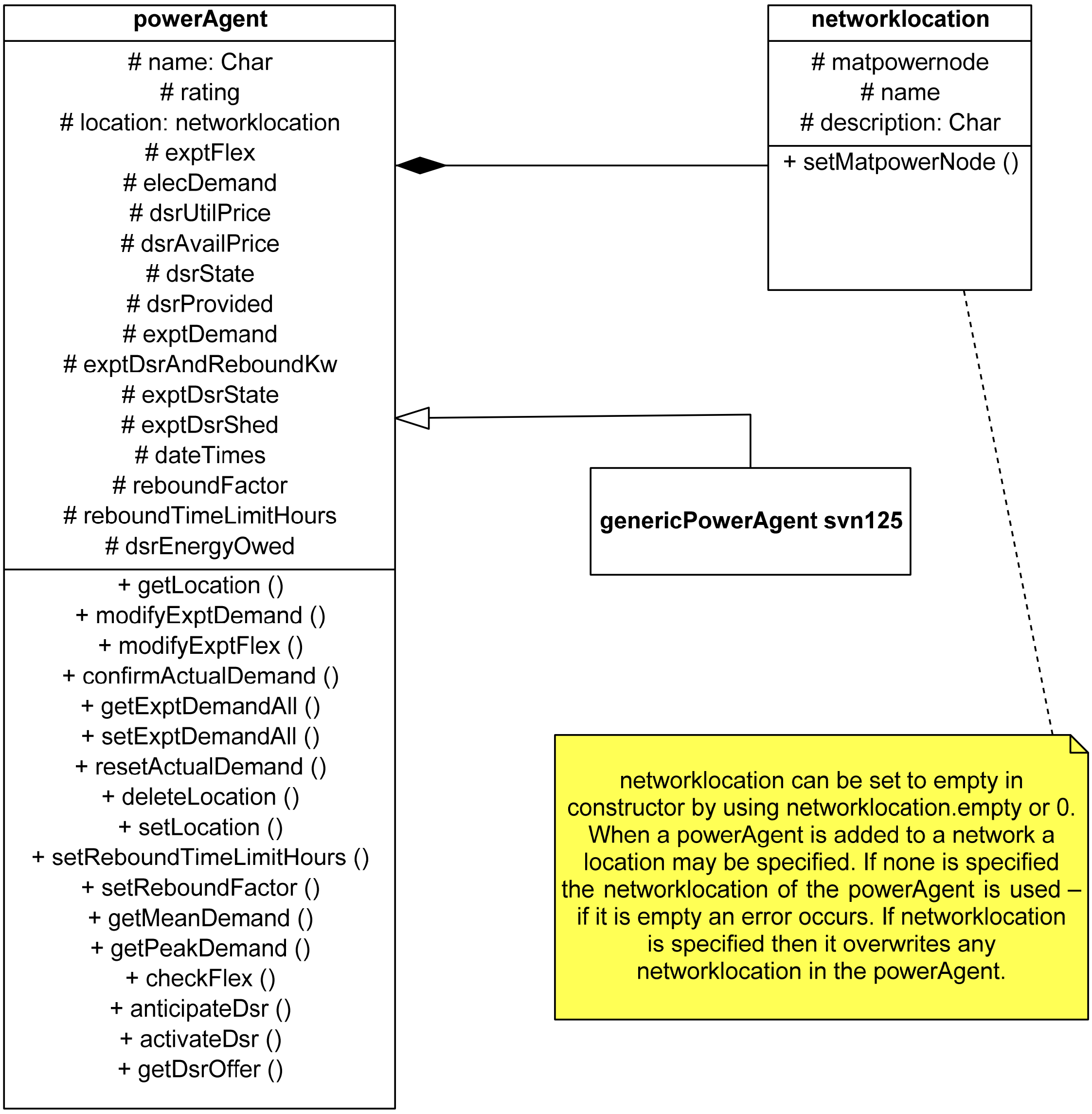
13.4.5.2. Areas for future development

Future development should include positive and negative flexibility as different elements so that it is possible for a powerAgent to model both concurrently.

powerAgent	superclass name:	
Attributes		
	handle	
Attribute Name	Default Value	Defining Class
dateTimeFormat	dd/mm/yyyy HH:MM:SS	powerAgent
name	empty	powerAgent
rating	--	powerAgent
location	--	powerAgent
dsrUtilPrice	--	powerAgent
dsrAvailPrice	--	powerAgent
elecDemand	--	powerAgent
dsrState	--	powerAgent
dsrProvided	--	powerAgent
exptDemand	--	powerAgent
exptDsrAndReboundKw	--	powerAgent
exptFlex	--	powerAgent
exptDsrState	--	powerAgent
exptDsrShed	--	powerAgent
dateTimes	--	powerAgent
reboundFactor	--	powerAgent
reboundTimeLimitHours	--	powerAgent
dsrEnergyOwed	--	powerAgent

powerAgent *Methods (part 1)*	superclass name: handle	
METHOD	**INPUTS**	**OUTPUTS**
modifyExptFlex	kw startTime endTime	deltaFlex
modifyExptDemand	kw startTime endTime	deltaDemand
getExptDemandAll	--	currentExptDemand
setExptDemandAll	newExptDemand	
resetActualDemand	--	
deleteLocation	--	
setLocation	newLocation	
getLocation	--	loc
setReboundTimeLimitHours	newReboundTimeLimitHours	
setReboundFactor	newReboundFactor	
powerAgent	name rating location exptDemand	<constructor>

	exptFlex dateTimes reboundFactor reboundTimeLimitHours defaultDsrUtilPrice defaultDsrAvailPrice	
getDsrOffer	endTime minKw	dsroffer
activateDsr	--	answer kwResponse startTime endTime
anticipateDsr	--	answerAcceptDeny kwPlanned startTime endTime
checkFlex	--	flexible answerTxt kwGranted startTime endTime
getPeakDemand	--	peakD
getMeanDemand	--	meanD
confirmActualDemand	--	meanD



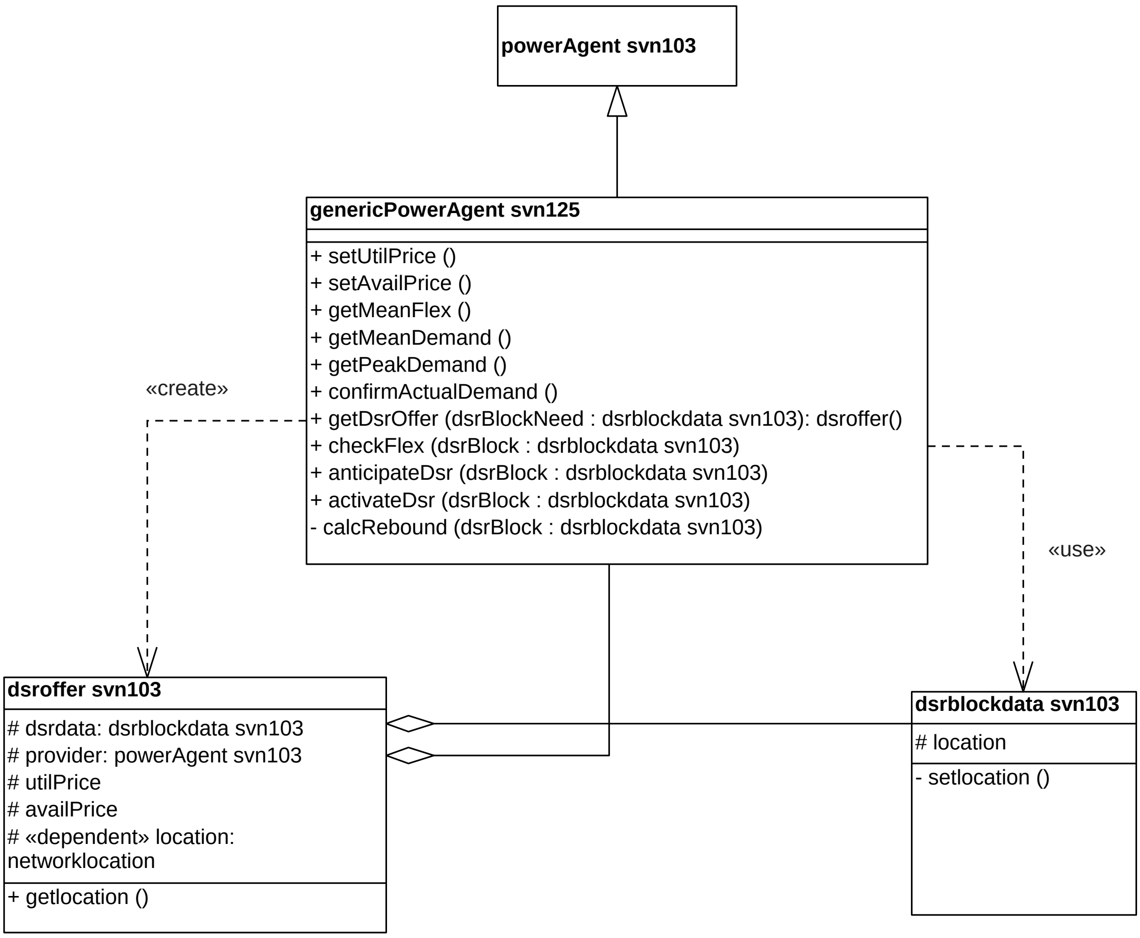
13.4.6. genericPowerAgent

When the genericPowerAgent is created it has an expected demand profile and an empty actual demand profile which are time series of values. In the absence of any changes the values in actual demand profile are set to the expected demand profile values (for a given time period) by the method activateDsr. The expected demand profile values represent default values (which can be changed/updated as new information becomes available). The actual demand profile values represent what actually happened with the power agent.

The normal procedure for modelling DSR would be as follows:

- if there is a request for DSR the method *checkFlex* checks the expected demand profile to see if the DSR request could be accommodated. But it does not take any actions (since the requester may have a better/cheaper offer of DSR from a different agent) and does not write to/alter any attributes.

- If a DSR request is made and contracted the method *anticipateDsr* will modify the expected demand values for that period including rebound (demand recovery) so that it knows what to expect in the future. It checks for demand limiting and if necessary saturates/limits at the power rating or zero. The method *anticipateDsr* can be thought of as reserving the flexibility (and demand) for that DSR activation.
- The *activateDsr* function will update the *elecDemand* but does not change the expected demand (because usually this will have been modified for the DSR in the *anticipateDs*r method. The *activateDsr*



	modifies	
method	expected demand	actual demand
checkFlex	-	-
anticipateDsr	✓	-
activateDsr	-	✓

Table 52 Methods in *powerAgent* and the attributes which they modify

The method *getMeanDemand* returns the mean expected or actual demand between a given start and end time. If the actual demand exists for the whole time between start and end the actual demand is returned. It also returns a message to say whether the actual or expected has been returned

The method *getPeakDemand* returns the expected or actual peak demand between a given start and end time. If the actual peak demand exists for the whole time between start and end the actual peak demand is returned. Also returns a message to say whether the actual or expected has been returned

The method *confirmActualDemand* takes values from exptDemand and writes them to elecDemand between a given start and end time. Any values which have already been confirmed (i.e. which exist in elecDemand) are ignored – they are not overwritten. The mean value of elecDemand between the start and end time is returned.

The method *checkFlex* determines whether DSR can be accommodated between a given start and end time. DSR kw is a fixed number and data structure is type dsrblock. The method takes into account flexibility, expected rebound, flexibility during rebound, rating and demand (i.e. is there enough demand to be reduced). Returns a logical (true = there is enough flexibility) and a message to say whether there is enough flexibility or not and if not a reason for this.

The method *anticipateDsr* updates the exptFlex for possible DSR calls (e.g. if a contract for DSR is made). exptDemand is not updated because the DSR might not be called. Normally checkFlex would be called before this method. This method returns a logical to say whether the DSR would be limited or not, a message about any limiting or rebound and the new exptFlex (for the period of DSR).

The method *activateDsr* will update elecDemand without checking exptFlex, but it will not let demand be < 0 or > rating. Normally anticipateDsr would be called prior to this function to 'reserve' the flexibility and report on any potential limiting

The method *calcRebound* calculates the start time, end time and kW of the demand recovery.

13.4.6.1. Unit testing

The following methods are tested:

- *checkFlex*
- *exptDemand*
- *anticipateDsr*

13.4.6.2. Areas for future development

The method *anticipateDsr* should return a boolean to indicate whether the DSR has been anticipated/whether there is enough flexibility. The method `anticipateDsr` is not included in the unit testing.

genericPowerAgent	superclass name: powerAgent	
Attribute Name	**Default Value**	**Defining Class**
dateTimeFormat	dd/mm/yyyy HH:MM:SS	powerAgent
name	empty	powerAgent
rating		powerAgent
location		powerAgent
dsrUtilPrice		powerAgent
dsrAvailPrice		powerAgent
elecDemand		powerAgent
dsrState		powerAgent
dsrProvided		powerAgent
exptDemand		powerAgent
exptDsrAndReboundKw		powerAgent
exptFlex		powerAgent

exptDsrState		powerAgent
exptDsrShed		powerAgent
dateTimes		powerAgent
reboundFactor		powerAgent
reboundTimeLimitHours		powerAgent
dsrEnergyOwed		powerAgent
METHOD	**INPUTS**	**OUTPUTS**
getDsrOffer	dsrBlockNeed	resultBool
		dsrOffer
activateDsr	dsrblock	powerLimitBool
		answerTxt
		dsrProvided
anticipateDsr	dsrblock	powerLimitBool
		answerTxt
		exptFlex
checkFlex	dsrblock	flexibleBool
		answerTxt
confirmActualDemand	startTime	powerLimitBool
	endTime	answerTxt
getPeakDemand	startTime	peakD
	endTime	msg
getMeanDemand	startTime	meanDCmplxKva
	endTime	msg

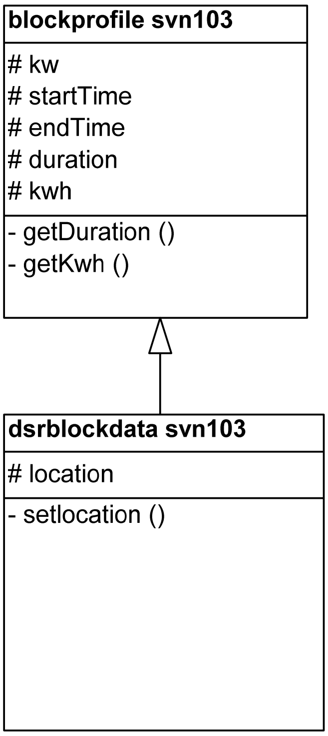
setAvailPrice	price	result
setUtilPrice	price	result
genericPowerAgent	name	<constructor>
	rating	
	location	
	exptDemand	
	exptFlex	
	dateTimes	
	reboundFactor	
	reboundTimeLimitHours	
	defaultDsrUtilPrice	
	defaultDsrAvailPrice	
calcRebound	dsrblock	startReboundTime
		endReboundTime
		kwRebound
empty	--	E
modifyExptFlex	kw	deltaFlex
	startTime	
	endTime	
modifyExptDemand	kw	deltaDemand
	startTime	

	endTime	
getExptDemandAll	--	currentExptDemand
setExptDemandAll	newExptDemand	
resetActualDemand	--	
deleteLocation	--	
setLocation	newLocation	
getLocation	--	loc
setReboundTimeLimitHours	newReboundTimeLimitHours	
setReboundFactor	newReboundFactor	

13.4.7. Blockprofile and dsrBlockData

The class *blockprofile* defines a demand profile of constant power for a fixed duration. It can be used to represent reduced power due to a demand side response (in which case the value for kw is negative). The attributes *duration* and *kwh* are dependent variables meaning that they are calculated at the time they are accessed. This is because they depend on one or more of *kw*, *startTime* and *endTime*. In the UML diagram this is represented by private methods *getDuration* and *getKwh*.

The class *dsrblockdata* is very similar to blockprofile but it also has a location so that it can be interfaced with Matpower.



blockprofile	**superclass name:** handle	
Attribute Name	Default Value	Defining Class
kw	--	blockprofile
startTime	--	blockprofile
endTime	--	blockprofile
[DEP] duration	--	blockprofile
[DEP] kwh	--	blockprofile
METHOD	INPUTS	OUTPUTS
blockprofile	kw startDateTime endDateTime	<constructor>

dsrblockdata	superclass name: blockprofile	
Attribute Name	Default Value	Defining Class
location	--	dsrblockdata
kw	--	blockprofile
startTime	--	blockprofile
endTime	--	blockprofile
[DEP] duration	--	blockprofile
[DEP] kwh	--	blockprofile
METHOD	**INPUTS**	**OUTPUTS**
dsrblockdata	kw	<constructor>
	startDateTime	
	endDateTime	
	locationIn	

13.4.7.1. Unit testing

(none so far)

13.4.7.2. Areas for future development

(none at present)

13.4.8. powerNetwork

The *powerNetwork* class acts as an interface between Matpower and other classes. It stores data on the Matpower network including location data (bus names etc.) The class has no knowledge of time or demand profiles but will run a power flow on a single set of demands.

The methods which act on the network use location data (type:networklocation) to describe buses. The networklocations are generated during construction of this object. They are either default values or with bus names specified. **Note that networklocations can only be set in the constructor and cannot be altered later. This is because the**

attributes of networklocation are protected. Default values have a description which is the Matpower bus number as a string type. To specify the bus names an additional input to the constructor is required. This is a cell array with bus numbers in the first column and names in the second column.

A list of network locations is kept in property busLocationList which is a row vector (1xn) of networklocations. In general bus locations are stored as 1xn unlike Matpower which stores them as column vectors. The class has private (‘protected’) methods which access the Matpower network by Matpower bus number but the public methods use network locations

Branches are accessed by specifying two network locations (the from and to buses).

After running a power flow the results are stored in the attribute *pfResults*. Methods which interact with Matpower directly are can only be accessed by child classes. The attribute *powerFlowUpToDate* is used to keep track of whether the power flow needs to be run. Any method which changes the Matpower mpc struct will set *powerFlowUpToDate* to be false. Any methods that access the power flow results, *pfResults*, will first interrogate *powerFlowUpToDate* and run a power flow if it is false.

In general set methods are applied to a single bus or branch whilst get methods return values for all buses/branches and a separate list of buses/branches. A list of branches has 2 columns, the from-bus and the to-bus.

Values for power inputs/outputs are be complex numbers representing real and reactive power.

Constraints are determined with the method *checkForConstraints*. This returns a Boolean value which indicates whether the network is constrained or not. If there is a thermal constraint the branch or branches on which this occurs is returned as two bus locations per constraint. If the voltage on any buses is above the statutory limit the bus or buses where this occurs are returned. The same is true for any buses with a voltage below the statutory limit.

The method getVoltsAllBusNodes returns all the voltages on all the buses as complex per unit (p.u.) values and voltage magnitude (p.u.) and angle (degrees).

powerNetwork	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
busLocationList	--	powerNetwork
thermalOverloadBus	--	powerNetwork
thermalOverload	0	powerNetwork
vOutOfBoundsHigh	0	powerNetwork
vOutOfBoundsLow	0	powerNetwork
overVoltBus	--	powerNetwork
underVoltBus	--	powerNetwork
vOutOfBounds	--	powerNetwork
constrained	--	powerNetwork
resultsUpToDate	0	powerNetwork
[DEP] nBranches	--	powerNetwork
[DEP] nBusNodes	--	powerNetwork
mpc	--	powerNetwork
pfResults	--	powerNetwork
PQ	--	powerNetwork
PV	--	powerNetwork
REF	--	powerNetwork
NONE	--	powerNetwork
BUS_I	--	powerNetwork
BUS_TYPE	--	powerNetwork
PD	--	powerNetwork
QD	--	powerNetwork
GS	--	powerNetwork
BS	--	powerNetwork
BUS_AREA	--	powerNetwork
VM	--	powerNetwork
VA	--	powerNetwork
BASE_KV	--	powerNetwork

ZONE	--	powerNetwork
VMAX	--	powerNetwork
VMIN	--	powerNetwork
LAM_P	--	powerNetwork
LAM_Q	--	powerNetwork
MU_VMAX	--	powerNetwork
MU_VMIN	--	powerNetwork
F_BUS	--	powerNetwork
T_BUS	--	powerNetwork
BR_R	--	powerNetwork
BR_X	--	powerNetwork
BR_B	--	powerNetwork
RATE_A	--	powerNetwork
RATE_B	--	powerNetwork
RATE_C	--	powerNetwork
TAP	--	powerNetwork
SHIFT	--	powerNetwork
BR_STATUS	--	powerNetwork
ANGMIN	--	powerNetwork
ANGMAX	--	powerNetwork
PF	--	powerNetwork
QF	--	powerNetwork
PT	--	powerNetwork
QT	--	powerNetwork
MU_SF	--	powerNetwork
MU_ST	--	powerNetwork
MU_ANGMIN	--	powerNetwork
MU_ANGMAX	--	powerNetwork
GEN_BUS	--	powerNetwork
PG	--	powerNetwork
QG	--	powerNetwork
QMAX	--	powerNetwork
QMIN	--	powerNetwork
VG	--	powerNetwork
MBASE	--	powerNetwork

GEN_STATUS	--	powerNetwork
PMAX	--	powerNetwork
PMIN	--	powerNetwork
PC1	--	powerNetwork
PC2	--	powerNetwork
QC1MIN	--	powerNetwork
QC1MAX	--	powerNetwork
QC2MIN	--	powerNetwork
QC2MAX	--	powerNetwork
RAMP_AGC	--	powerNetwork
RAMP_10	--	powerNetwork
RAMP_30	--	powerNetwork
RAMP_Q	--	powerNetwork
APF	--	powerNetwork
MU_PMAX	--	powerNetwork
MU_PMIN	--	powerNetwork
MU_QMAX	--	powerNetwork
MU_QMIN	--	powerNetwork
PW_LINEAR	--	powerNetwork
POLYNOMIAL	--	powerNetwork
MODEL	--	powerNetwork
STARTUP	--	powerNetwork
SHUTDOWN	--	powerNetwork
NCOST	--	powerNetwork
COST	--	powerNetwork

METHOD	**INPUTS**	**OUTPUTS**
getVPuLimits	--	busLocations puLimitsUpper puLimitsLower
setVPuLimitsAtLocation	location	

	vUpperPu vLowerPu	
getRatingsAllBranches	--	fromBusToBusLocs ratingsMva
setRatingAtBranch	fromBusToBusL ocs ratingMva	
getGenKvaAllLocations	--	busLocations genKvaAllLocations
setGenKvaAtLocation	networkLocation PQGenKva	
getDemandKvaAllLocations	--	busLocations demandKvaAllLocs
dispDemandKvaAllLocations	--	
setDemandKvaAtLocation	networkLocation PQDemandKva	
getDemandKvaAtLocation	networkLocation	PQDemandKva
getNetworkTopology	--	fromBusToBusLocs
dispNetworkTopology	--	
doNothing	--	
getLossMwAllBranchLocations	--	fromToLocs loss

getMaxMwAllBranchLocations	--	fromToLocs cmplxPowerMax
getMeanMwAllBranchLocations	--	fromToLocs cmplxPowerMean
getVoltsAllBusLocations	--	busLocationsList puVComplexAll puVMagAll vAngleAll
quickCheckForConstraints	--	wouldBeConstrained
checkForConstraints	--	constrained thermalFromToBusLocs voltHighOnBusLoc voltLowOnBusLoc
runPowerFlow	--	success
deleteDemandAllBusNodes	--	
getTotalDemandKva	--	totalDemandKva
findNetworkLocation	busNumOrDesc	locations
dispBuses	--	
getNetworkLocations	--	locationsList
powerNetwork	matpowerFileNa me busNumNameLis t	<constructor>

runPowerFlowMatpower	--	success
generateNetworkLocationData	busNumNameLis t	locations
loadNetwork	matpowerFileNa me	success
getLossMwAllBranchesMatpower	--	fromToBusNums loss
getMeanAndMaxMwAllBranchesMat power	--	fromToBusNums cmplxPowerMean cmplxPowerMax
getVoltsAllBuses	--	busNumsList puVMagAll vAngleAll
getFromBusToBusIndx_BranchData	busFromNumber busToNumber	branchIndx
getVPuLimitsMatpower	--	busList puLimitsUpper puLimitsLower
setVPuLimitsAtBus	bus vUpperPu vLowerPu	
getRatingsAllBranchesMatpower	--	busFromTo ratingsMva
setRatingAtBranchMatpower	busFrom	

	busTo ratingMva	
getGenKvaAllNodes	--	busList genKvaCmplx
setGenKvaAtBus	busNumber PQGenKva	
getDemandKvaAllBusNodes	--	busList demandCmplxKvaAllB uses
setDemandKvaAtBusNode	busNumber PQDemandKva	
getDemandKvaAtBusNode	busNumber	PQDemandKva
getBusIndx_GenData	busNumber	busIndx
getBusIndx_BusData	busNumber	busIndx
getListBusNums_GenData	--	list
getListBusNums_BusData	--	list

13.4.8.1. Unit testing

The following is a list of functions in the unit test:

```
function nBusNodes_and_nBranches(testCase)
function delete_and_set_demand(testCase)
function get_and_set_generation(testCase)
function test_get_set_Ratings(testCase)
function test_get_set_VPuLimits(testCase)
function getVoltsAllBusLocations(testCase)
function testMeanPowerFlowInLines(testCase)
function getLossMwAllBranches(testCase)
function constrainedNetwork(testCase)
```

```
function getNetworkLocations(testCase)
function findNetworkLocation(testCase)
```

13.4.8.2. Areas for future development

(none at present)

13.4.9. networkRunner

The method *runNetworkAllData* runs a powerflow on the network for the specified time period. This sets the attributes with names beginning with *output...* and *constraints...* Attributes beginning *output...* are used to record the network state with time, whilst the attributes beginning with *constraints...* are used to store network state when it is under a constraint (thermal or voltage).

Date/time data are arranged vector in a column, whilst bus and branch location data are stored in a row vector. A branch consists of 2 bus locations (2 rows) i.e. *from-bus* and *to-bus*.

Attribute names beginning *connList_..* are set in the constructor.

13.4.9.1. Finding constraints on the network

There are two methods for determining if a network is constrained. The *runNetworkAllData* method sets the constraints attributes. The method *runNetworkCheckConstraintOnly* does not set the constraints attributes and is used as a quicker method to check whether there was a constraint or not. The latter method is useful when trying to determine the level/scale of demand increase which causes a constraint.

Note that everytime the *runNetworkAllData* method is used new entries are made to the constraint attributes even if they are identical to existing entries (e.g. if the method is run twice with the same inputs and unaltered powerAgents there will be two sets of identical data stored). The constraint data may be cleared before invoking the method – however, if testing different time periods it may be desired to keep existing constraint results.

The constraint data can be printed to the command window with method *dispConstraintsList(startDay, endDay)*. Alternatively it can be stored as variables with the function *[constraintDateTime, constraintLocation, constraintType, demandAtConstraint] = getConstraintsList()*. Note that *startDay*, *endDay* must be whole days.

13.4.9.2. Organisation of constraints data

The constraints data is set by *runNetworkAllData* and consists of:

constraintsDateTimeList
constraintsLocList
constraintsTypeList
constraintsTotalDemandKva

Constraints dateTime list is in a single column array of double (nx1). The dateTimes will not necessarily be ordered, they are just dateTimes relating to constraint data having the same array index. It should also be noted that adjacent cells may contain the same dateTime, for example if a thermal and voltage constraint occur at the same time or if there are under- and over-voltage constraints at different locations at the same time, for example:

The type of constraint is stored in a cell array of n rows. Each cell contains a string. Thermal, over voltage and under-voltage constraints are stored separately. Each row corresponds to the same row of *constraintsDateTimeList* for example:

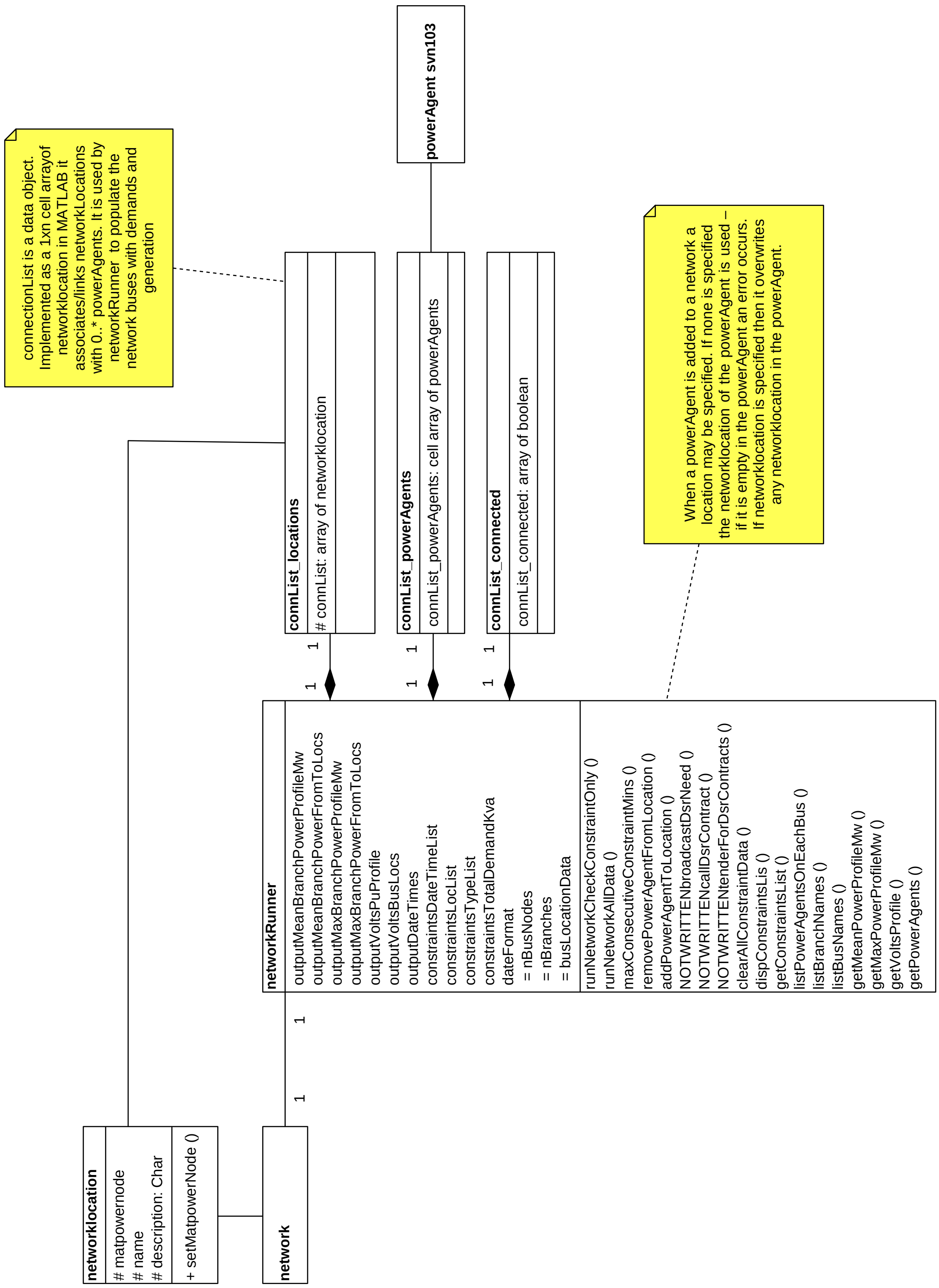
The location of a constraint depends on whether the constraint is thermal or due to voltage i.e. the constraint could be in a branch or on a bus. As stated previously a branch consists of 2 bus locations (from- and to-bus) and these are stored in a cell which contains two rows, whilst for a voltage constraint a cell with only 1 row is needed. For each type of constraint there may be more than one branch/bus which is constrained and these are all stored. Therefore for a thermal constraint the size of the cell content is 2xn where n is the number of constrained branches, but for voltage constraints the size of the cell contents is 1xm where m is the number of buses which are over- or under-voltage. In *constraintsLocList* the entries are stored as cells which contain an array of type *networklocation*. An example is shown in Table 53. Details for the *networklocation* class are described elsewhere in this document.

constraintsLocList cell {nx1}
{2x6 networklocation}
{1x1 networklocation}
{1x3 networklocation}
{2x6 networklocation}
{1x1 networklocation}
{1x3 networklocation}

Table 53 An example of how the constraint locations are stored

In Table 53 which describes the *constraintsLocList* the cell in the first row has 2 rows of network locations which indicates that these are branches. So it contains branch information for 6 branches. (This means that 6 branches were thermally overloaded - non-overloaded are not reported. The second row cell has only one row of location data meaning it is a bus and only has one element. (This means only one bus had a voltage issue. Referring to the constraintsTypeList 2^{nd} row element it can be seen that this was an over-voltage.

The total network demand when the constraint occurred is stored in *constraintsTotalDemandKva* which is an array of type double.


connectionList is a data object. Implemented as a 1xn cell arrayof networklocation in MATLAB it associates/links networkLocations with 0..* powerAgents. It is used by networkRunner to populate the network buses with demands and generation
powerAgent svn103
connList_locations
connList: array of networklocation
connList_powerAgents
connList_powerAgents: cell array of powerAgents
connList_connected
connList_connected: array of boolean
When a powerAgent is added to a network a location may be specified. If none is specified the networklocation of the powerAgent is used – if it is empty in the powerAgent an error occurs. If networklocation is specified then it overwrites any networklocation in the powerAgent.
1
1
1
1
1
1
networkRunner
outputMeanBranchPowerProfileMw
outputMeanBranchPowerFromToLocs
outputMaxBranchPowerProfileMw
outputMaxBranchPowerFromToLocs
outputVoltsPuProfile
outputVoltsBusLocs
outputDateTimes
constraintsDateTimeList
constraintsLocList
constraintsTypeList
constraintsTotalDemandKva
dateFormat
= nBusNodes
= nBranches
= busLocationData
runNetworkCheckConstraintOnly ()
runNetworkAllData ()
maxConsecutiveConstraintMins ()
removePowerAgentFromLocation ()
addPowerAgentToLocation ()
NOTWRITTENbroadcastDsrNeed ()
NOTWRITTENcallDsrContract ()
NOTWRITTENtenderForDsrContracts ()
clearAllConstraintData ()
dispConstraintsLis ()
getConstraintsList ()
listPowerAgentsOnEachBus ()
listBranchNames ()
listBusNames ()
getMeanPowerProfileMw ()
getMaxPowerProfileMw ()
getVoltsProfile ()
getPowerAgents ()
1
1
networklocation
matpowernode
name
description: Char
+ setMatpowerNode ()
network

networkRunner	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
connList_locations	--	networkRunner
connList_powerAgents	--	networkRunner
connList_connected	--	networkRunner
network	--	networkRunner
outputVoltsPuProfile	--	networkRunner
outputVoltsBusLocs	--	networkRunner
outputDemandAtBusesKva	--	networkRunner
outputDemandAtBusesKvaBusLocs	--	networkRunner
outputMeanBranchPowerProfileMw	--	networkRunner
outputMeanBranchPowerFromToLocs	(empty)	networkRunner
outputMaxBranchPowerProfileMw	--	networkRunner
outputMaxBranchPowerFromToLocs	(empty)	networkRunner
outputBranchLossesKva	--	networkRunner
outputBranchLossesKvaFromToLocs	(empty)	networkRunner
outputDateTimes	--	networkRunner
constraintsDateTimeList	(empty)	networkRunner
constraintsLocList	(empty)	networkRunner
constraintsTypeList	(empty)	networkRunner
constraintsTotalDemandKva	(empty)	networkRunner
dateFormat	ddd dd-mmm-yyyy HH:MM:SS	networkRunner
[DEP] nBusNodes	--	networkRunner
[DEP] nBranches	--	networkRunner

[DEP] busLocationData	--	networkRunner
METHOD	**INPUTS**	**OUTPUTS**
runNetworkCheckConstraintOnly	sDay eDay timeStepMins	constrained
runNetworkAllData	sDay eDay timeStepMins	constrained
removePowerAgentFromLocation	netLocation	
addPowerAgentToLocation	powerAgent netLocation	
NOTWRITTENbroadcastDsrNeed	--	
NOTWRITTENcallDsrContract	--	
NOTWRITTENtenderForDsrContracts	--	
clearAllConstraintData	--	
dispConstraintsList	startDateTime endDateTime	
getConstraintsList	--	dateTimeList locList

		consTypeList totalDemandKva
listPowerAgentsOnEachBus	--	busNamePowerAgentNameConnected
listBranchNames	--	branchNames
listBusNames	--	busNames
getDemandAtBusesKva	--	dateTimes DemandAtBusesKvaBusLocs DemandAtBusesKva
getBranchLossesKva	--	dateTimes fromToBusLocs Losses BranchLossesKva
getMeanPowerProfileMw	--	dateTimes fromToBusLocs MeanP meanPowerProfileMw
getMaxPowerProfileMw	--	dateTimes fromToBusLocs MaxP maxPowerProfileMw

getVoltsProfile	--	dateTimes vProfileBusLocs voltsPuProfile
clearAllOutputData	--	
getPowerAgents	--	pAgents
networkRunner	powerNetwork	<constructor>
setDemandsOnBusesByInterrogatingPowerAgents	sTime eTime	powerLimitBool
deleteAllGeneration_Matpower	--	
deleteAllDemand_Matpower	--	
connIndx_GetIndxForLocation	netLocation	connIndx
connList_GetIndxForPowerAgent	powerAgent	indx
connList_CheckPowerAgentDuplicate	powerAgent	

13.4.10. storScheduler

The STOR scheduler set of classes produces representative STOR calls based on statistical data on the STOR calls and the expected number of calls in a year.

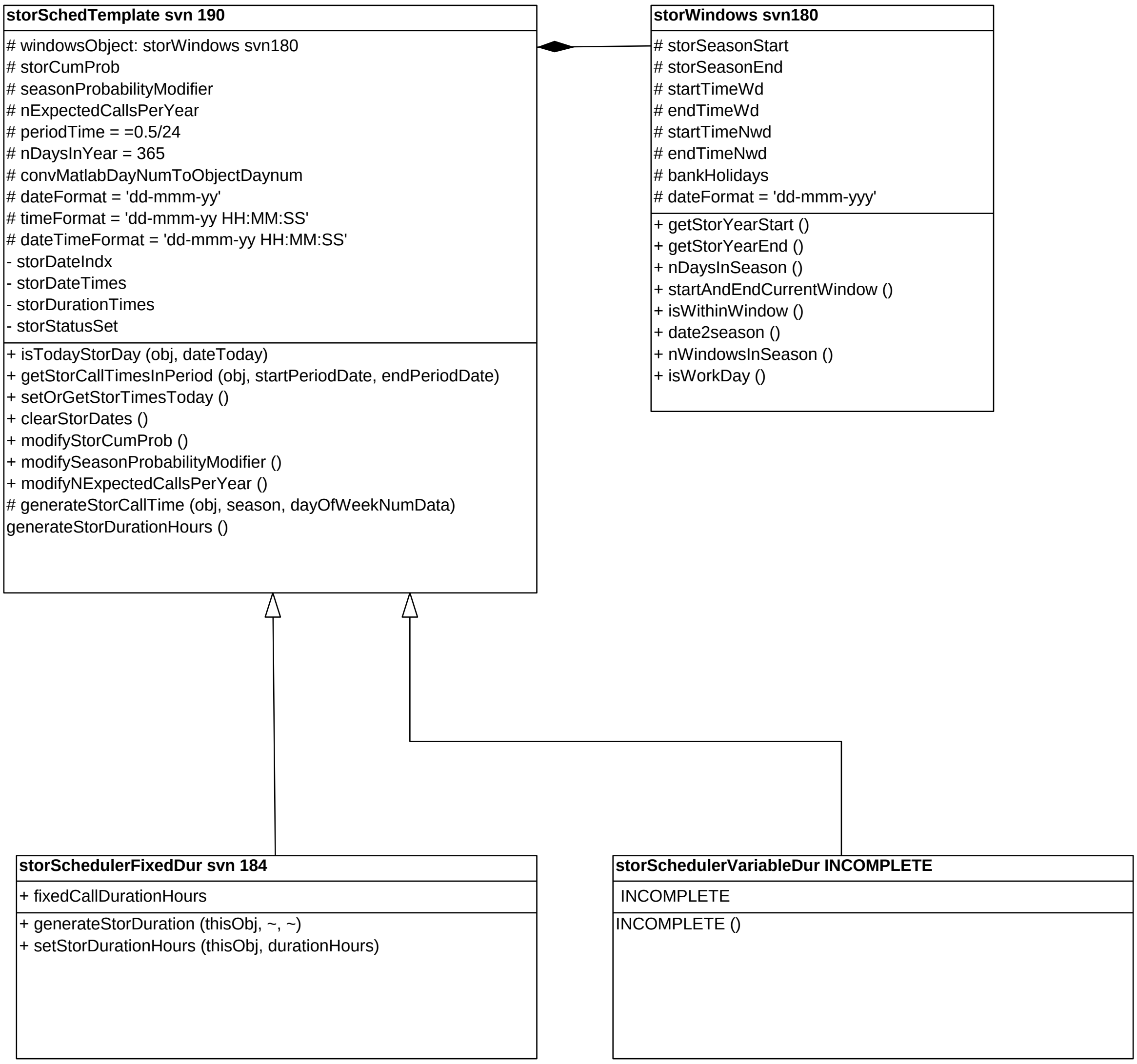
Note that STOR calls which would finish after the end of a window (due to the fixed duration) are curtailed to end at the end of the window. This means that there is a higher incidence of STOR calls ending at those times as shown in the histogram but the start times are unaffected.

13.4.10.1. Unit testing

```
function test_nExpectedCalls(testCase)
function nCalls(testCase)
function clearStorDates_and_getStorCallTimesInPeriod2(testCase)
function setOrGetStorTimesToday(testCase)
function modifyNExpectedCallsPerYear(testCase)
function generateStorDurationHours(testCase)
function setStorDurationHours(testCase)
```

13.4.10.2. Areas for future development

Add methods getStorYearStart and getStorYearEnd to storSchedTemplate. The unit test does not test the probability of STOR calls for different seasons, times etc. A unit test for setOrGetStorTimesToday() not written.



storSchedTemplate	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
windowsObject	--	storSchedTemplate
storCumProb	--	storSchedTemplate
utilPerSeason	--	storSchedTemplate
totalUtil	--	storSchedTemplate
nExpectedCallsPerYear	--	storSchedTemplate
periodTime	0.0208	storSchedTemplate
nDaysInYear	365	storSchedTemplate
dateFormat	dd-mmm-yy	storSchedTemplate
timeFormat	HH:MM:SS	storSchedTemplate
dateTimeFormat	dd-mmm-yy HH:MM:SS	storSchedTemplate
storDateIndx	--	storSchedTemplate
storStartDateTimes	--	storSchedTemplate
storDurationTimes	--	storSchedTemplate
storStatusSet	--	storSchedTemplate
METHOD	INPUTS	OUTPUTS
generateStorDurationHours	season dayOfWeek	storDurationHours
modifyNExpectedCallsPerYear	nExpectedCallsPerYear	
clearStorDates	--	
setOrGetStorTimesToday	dateToday	storStart storEnd result resultTxt

getStorCallTimesInPeriod	startPeriodDate endPeriodDate	storCallsStartEndTimesInPeriod nCalls
isTodayStorDay	dateToday	isStorDayBool resultTxt
storSchedTemplate	windowsObject storCumProb utilPerSeason totalUtil nExpectedCallsPerYear	<constructor>
generateStorCallStartAndEndTime	season dateToday	timeStorStart timeStorEnd

storSchedulerFixedDur	**superclass name:** storSchedTemplate	
Attribute Name	**Default Value**	**Defining Class**
fixedCallDurationHours	--	storSchedulerFixedDur
windowsObject	--	storSchedTemplate
storCumProb	--	storSchedTemplate
utilPerSeason	--	storSchedTemplate
totalUtil	--	storSchedTemplate
nExpectedCallsPerYear	--	storSchedTemplate
periodTime	0.0208	storSchedTemplate
nDaysInYear	365	storSchedTemplate
dateFormat	dd-mmm-yy	storSchedTemplate
timeFormat	HH:MM:SS	storSchedTemplate
dateTimeFormat	dd-mmm-yy HH:MM:SS	storSchedTemplate
storDateIndx	--	storSchedTemplate
storStartDateTimes	--	storSchedTemplate
storDurationTimes	--	storSchedTemplate
storStatusSet	--	storSchedTemplate
METHOD	INPUTS	OUTPUTS
setStorDurationHours	durationHours	
generateStorDurationHours	~ ~	storDurationHours
storSchedulerFixedDur	windowsObject storCumProb utilGwhPerSeason	<constructor>

	totalGwhUtil nExpectedCallsPerYear fixedCallDurationHours	
modifyNExpectedCallsPerYear	nExpectedCallsPerYear	
clearStorDates	--	
setOrGetStorTimesToday	dateToday	storStart storEnd result resultTxt
getStorCallTimesInPeriod	startPeriodDate endPeriodDate	storCallsStartEndTimesInPeriod nCalls
isTodayStorDay	dateToday	isStorDayBool resultTxt
generateStorCallStartAndEndTime	season dateToday	timeStorStart timeStorEnd

13.4.11. storWindows

storWindows	**superclass name:** handle	
Attribute Name	**Default Value**	**Defining Class**
storSeasonStart	--	storWindows
storSeasonEnd	--	storWindows
startTimeWd	--	storWindows
endTimeWd	--	storWindows
startTimeNwd	--	storWindows
endTimeNwd	--	storWindows
bankHolidays	--	storWindows
dateFormat	dd-mmm-yyyy	storWindows
METHOD	INPUTS	OUTPUTS
isWorkDay	date	workDay
nWindowsInSeason	season	nWindowsWd nWindowsNwd
date2season	date	season
isWithinWindow	dayDatenum	isInWindowBool sWindowTime eWindowTime
startAndEndCurrentWindow	dayDatenum	sWindow eWindow
nDaysInSeason	season	nDays
getStorYearEnd	--	storYearEnd

getStorYearStart	--	storYearStart
storWindows	storSeasonStart storSeasonEnd startTimeWd endTimeWd startTimeNwd endTimeNwd bankHolidays	<constructor>