Coordination of quadrature booster transformers

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This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.

Signed: *Emmanouil Belivanis* Date: *July 2022*

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List of Abbreviations

BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
CA	Contingency Analysis
CCGT	Combined Cycle Gas Turbine
C-SCOPF	Corrective Security Constraint Optimal Power Flow
CWE	Central West Europe
DC	Direct Current
DNO	Distribution Network Owner
ELSI	Electricity Scenario Illustrator (model)
EMS	Energy Management System
ESO	Electricity System Operator (the independent SO of Great Britain)
ETYS	Electricity Ten Year Statement
EU	European Union
FACT	Flexible Alternating Current Transmission (device/system)
FES	Future Energy Scenarios
GB	Great Britain
HV	High Voltage
HVDC	High Voltage Direct Current
LCC	Line Commutated Converter
LP	Linear Programming
LTC	Load Tap Changer
MILP	Mixed Integer Linear Programming
MINLP	Mixed Integer Non-Linear Programming
MIQP	Mixed Integer Quadratic Programming
MPC	Model Predictive Control
NETA	New Electricity Trading Arrangements
NGET	National Grid Electricity Transmission (a Great Britain Transmission Owner)
NOA	Network Options Assessment
NWE	North West Europe
OFTO	Offshore Transmission Owner
OHL	Overhead Line (ac)

OPF	Optimal Power Flow
PF	Power Flow
P-SCOPF	Preventive Security Constrained Optimal Power Flow
PST	Phase-shifting transformer
PTDF	Power Transfer Distribution Factor
QB	Quadrature Booster (transformer)
QBDF	Quadrature Booster Distribution Factor
QP	Quadratic Programming
RT	Required Transfer
SCADA	Supervisory Control and Data Acquisition
SC-OPF	Security Constrained Optimal Power Flow
SHET	Scottish Hydro Electric Transmission (a Great Britain Transmission Owner)
SO	System Operator
SPT	Scottish Power Transmission (a Great Britain Transmission Owner)
SQSS	Security and Quality of Supply Standard (the security standard of Great Britain)
SRF	System Requirements Form
TO	Transmission Owner
TSO	Transmission System Operator
TTC	Transmission Transfer Capacity
VSC	Voltage Source Converter
W-HVDC	West Coast HVDC link

Abstract

Quadrature booster (QB) transformers and other power flow control devices can help make better use of existing (or planned) electricity transmission network capacity. They are able to increase the transmission transfer capacity of an area – the power that can be securely transferred out of it or into it before there is a need for renewable or other high merit/low cost generation to be constrained off somewhere on the system – and thus enable a more economic operation of the system. The QBs are more effective when used in a coordinated way and the tap settings of multiple devices are optimised towards a common objective.

This work develops comprehensive and practical framework for the coordination of tap settings of multiple QBs based on mathematical programming methods. It takes into account many of the factors that system operator (SO) engineers must consider when preparing a plan of actions to operate the system in such a way that the cost of operating the system is minimised and the security and reliability is ensured.

The framework is used to examine alternative strategies (operational objectives) regarding the coordinated use of QBs. The two key parameters considered are the extent of use of QBs for preventive and corrective actions – both in isolation and when combined. Each strategy achieves a different level of economy and ‘complexity’ of operation while maintaining the same, pre-defined, level of security. A study is setup to calculate the preventive generation re-dispatch cost (constraint cost) that results from using the QBs according to each strategy and to help draw conclusions.

It is found that the active and coordinated use of QBs in multiple locations for preventive actions is the single most important parameter (amongst the two previously mentioned) in order to reduce constraint cost. It is recommended that strategies that favour the active preventive use of QBs are preferred against ones that limit the preventive use in order to maximise their post-fault utilisation. The reason for that is the different mechanisms through which the extent of preventive and corrective use of QBs contribute to the reduction of constraint cost.

It is also recommended that, if able, QBs are used for both preventive and corrective actions and to a high ‘extent’[1]. The analysis shows that, use of QBs in that way can result in a 36% reduction in the preventive generation re-dispatch cost, in the course of a simulated year of

1 The definition of the term 'extent' in the context of preventive and corrective QB use and the strategies of this thesis is given in Chapter 5. The figures mentioned are relevant to the study setup and assumptions used for the results of Chapter 5.

operation, over a strategy where QBs are not used at all for either preventive or corrective actions or 8.6% over a strategy where QBs are used for preventive and corrective actions but not to a high ‘extent’.

So, the novelty and contribution of this work is twofold. First, the developed framework is a comprehensive, practical and complete method for coordinating the QB tap settings and it also addresses many of the considerations of SO engineers in a way that it could be readily used to enhance existing processes. Second, it draws a clear conclusion regarding what is the best way to utilise the QB devices that is supported by bespoke analysis and data.

1 Introduction

The Great Britain (GB) transmission system has experienced an increase in power flows through most areas of the network in recent years as new renewable generation capacity was connected, for the most part, in areas further away from the demand centres. It is expected that the trend of increasing flows will be accelerated in the near future as more renewable and low carbon generation will connect to the networks to mitigate the impact of the ongoing climate change [1].

Quadrature booster (QB) transformers and other power flow control devices can help make better use of the existing (or planned) network capacity. They are able to increase the transmission transfer capacity of an area – the power that can be securely transferred before there is a need for renewable or other generation to be constrained off – and thus enable a more economic operation of the system [2]. The QBs are more effective when used in a coordinated way and the tap settings of multiple devices are optimised towards a common objective [3].

The optimal power flow (OPF) method and other mathematical programming based tools have found many proposed uses in power system operations over the years. It is however acknowledged that the adoption of the OPF methods at operational planning and operation timescales is not widespread amongst utilities and not fully integrated within their existing processes.

This work aims to develop a comprehensive and practical framework for the coordination of tap settings of multiple QBs based on mathematical programming methods. It tries to take into account many of the factors that system operator (SO) engineers must consider when preparing a plan of actions to operate the system in such a way that the preventive generation re-dispatch cost is minimised and the security and reliability is ensured.

In the following the scope of this work is defined in more detail. The QB coordination framework, as developed and presented in the following (section 4.3), corresponds to and can be directly used for the part of SO operations called operational planning or short-term planning that usually covers the period from a year into the future to the day(s) ahead of actual system operation[2]. As we come closer to the real-time operation various uncertainties can be better defined so ‘dispatch snapshots’ that overlay the expected demand and generation outrun[3]

2 Exact time periods are SO/organisation specific.
3 Coming from historic data, weather forecast or market clearance data for instance

onto a transmission network model can be formed and analysed. The QB coordination framework is made to be applied directly to such a snapshot.

Transmission expansion planning (or long-term planning) can also be thought as a targeted analysis of a number of these dispatch snapshots. The reason is that the criteria that apply during operation/short-term planning (i.e. how the dispatch snapshots are analysed) must correspond to (or be compatible with) the ones used for long-term planning [4] in order for the future network configuration (the output of the long-term planning process) to be compliant with present day operating standards. So, it is often that the 'macro-scenarios' developed for long-term planning (that take into account a range of possible future generation and demand outcomes and cover different eventualities at a high level) are brought down to a number of specific 'micro-scenarios'/dispatch snapshots that are analysed to help draw conclusions.

There is more than one way to derive micro-scenarios for use in long-term planning from the high level generation and demand projections/forecast. These could be through a 'worst-case' dispatch approach, through regulatory agreed dispatch assumptions [4][5], by solving an economic dispatch problem (as in the study setup of Chapter 5), through probabilistic sampling of certain variables [5] and more. To the extent that the above methods all produce one or more dispatch snapshots, the QB coordination framework can be applied to them and be used in the context of long-term planning as well. Section 5.1.4 provides more information on how the detailed output of the framework can be utilised if the dispatch snapshot it is applied to is derived in the context of short-term or long-term planning.

The primary output of the QB coordination framework, for every dispatch snapshot it is applied to, is a set of preventive actions – that use the QBs and other active power controls – to be applied at the beginning of the dispatch period and several sets of corrective actions that each would be applied in the event of a specific contingency. The preventive and corrective actions allow SOs to operate the system in a way that, if specific events happen, certain consequences are avoided or mitigated [6]. The security standards define these events and consequences in detail [4]. The type of event the QB coordination framework can be used for is forced branch outage contingencies and the type of consequence is branch overload above the continuous rating[6].

Operating within the requirements of the security standards allows for a set, predefined level of security to be adhered to i.e. the one envisioned when setting the events and consequences

4 This is explained in more detail in section 2.2.1
5 This is the dispatch criteria behind the Required Transfer of reference [4] explained in more detailed in section 2.2.2
6 Note there are other aspects of power system security and further metrics of security and reliability that are outside the scope of this work. For the former you can refer to [4] and for the latter to reference [27].

in the standards. While operating within these requirements, the economy of operation (the cost of payments SO’s makes to market participants to change their output to balance the system and manage constraints) can still vary depending on how QBs and other active power controls are used [7].

The framework makes use of corrective actions to mitigate the consequences of a contingency and only uses preventive actions where corrective actions do not apply and to the extent necessary so that corrective actions become possible. It uses QBs in a coordinated way with one another and with the other active power controls to provide a minimum cost set of preventive actions[7]. Through both these features it aims to minimise the preventive generation re-dispatch cost (the portion of operational cost that the consumer is always exposed to) that is the metric of how successful an operating strategy is in the results presented on Chapter 5.

Further, it should be noted that the scope of this work is most relevant to applications where the following three conditions apply: the network connectivity is (relatively) highly meshed; multiple circuits cross an area where power flows through – not all having the same capacity or being equally loaded; QB devices are installed in several locations. The coordination of QB tap settings is more of a concern [8] under these conditions but there is also greater opportunity to improve transmission transfer capacity [3]. The first two can generally be found in transmission networks and one example where all three apply is the north/middle England region of the GB transmission system [9]. Indeed, in the following the GB system network and operations is used as an example for the study setup and result of Chapter 5 but it should be noted that the framework could be used in other applications/power system examples as required.

1.1 Text organisation

The following chapters are organised as follows. Chapter 2 provides background information and research regarding power system operation, planning, economics and optimisation. It enables the reader to make better use of the topics covered in the subsequent chapters. First, an overview of the Great Britain electricity market arrangements is provided including the roles and responsibilities of the key stakeholders. Using the concept of the transmission boundary, the functions of power system operation and planning and the role of power flow control devices are introduced. It is explained how the quadrature booster transformers

7 Note that some of the above are controlled by user defined parameters in the framework.

installed on the Great Britain transmission system are currently utilised. Further, a review of the OPF method with its strengths and shortcomings is provided.

In Chapter 3, a number of OPF models are developed, each covering a different aspect of how the OPF method can be used to re-dispatch active power controls. First, a basic OPF model is developed step-by-step and the modelling choices made in each step are explained. The model is then expanded to include the various objectives that the SO engineers must consider in day to day operation and operational planning, such as using up to a predefined number of controls for corrective actions or the use of the most effective controls only. Engineering practice and research in these topics is presented. Following that, the security constrained optimal power flow (SC-OPF) method, that expands the OPF to include the network configurations that result from a number of unplanned transmission outages, is introduced. The 'preventive' and 'corrective' SC-OPF variation are explained and a discussion about the "direct" modelling approach, that requires that the constraints of the 'base' network configuration and those of the contingency configurations are included in the same OPF model, is provided.

Chapter 4 brings together some of the OPF models developed in Chapter 3 into a comprehensive and practical framework for the QB tap settings coordination. The chapter starts by reviewing a number of approaches for limiting the size of the "direct" SC-OPF problem including decomposition or iterative methods. Following that, it sets out the requirements for the QB coordination framework. What is it that "coordination" is trying to achieve, what should the objective be in the different states that the power system can find itself in and what are the outputs that SO engineers require are some of the questions considered. In the second part of the chapter, the QB coordination framework is developed. It is an iterative procedure for minimising the preventive generation re-dispatch cost that consists of the following three steps: a preventive SC-OPF step, a step that tests if the criteria for operating with corrective security apply and a contingency and rating selection step.

Chapter 5 begins by describing the study setup used for testing the use of QBs through the coordination framework. A representative test model that preserves the main features of the GB transmission network and a year round economic dispatch tool that provides a series of generation and demand dispatch snapshots are used. Next, a number of strategies regarding the use of QBs and other active power controls are outlined. A strategy is a combination of settings or SO preferences regarding the preventive and corrective use of QBs and other active power controls. The rationale behind the choice of each strategy and how it finds uses in SO operations is explained. Overall, the test model, the dispatch snapshots and the strategies provide a consistent background to apply the coordination framework on and help to draw conclusions.

The output of this study is also presented in Chapter 5. The preventive generation re-dispatch cost of each strategy is compared and the reasons behind the observed differences are analysed. The mechanisms of how increasing the preventive or corrective use of QBs, through the use of the coordination framework, helps reduce the preventive generation re-dispatch cost are explained and the impact of each of these two factors is quantified.

Finally, Chapter 6 brings together the main conclusions of this work and outlines what further work may be required.

1.2 List of publications

The research leading to this thesis resulted to the following research papers. The first two papers provide an overview of the issue of coordination of QB tap settings, of their use in the GB system and some examples of coordinated operation. Further to the above, the third paper also includes an early version of the coordination framework of Chapter 4 of this thesis. The representative test model (used for the results of Chapter 5 of this thesis) was utilised on the last two papers where modelling and power system input was provided. The first three papers have been cited in total 47 times[8].

- M. Belivanis and K. R. W. Bell, "Use of phase-shifting transformers on the transmission network in Great Britain" in 45th International Universities Power Engineering Conference, 2010.
- M. Belivanis and K. R. W. Bell, "Coordination of phase-shifting transformers to improve transmission network utilisation", in 2010 IEEE PES Innovative Smart Grid Technologies Conference Europe, 2010.
- M. Belivanis and K.R.W. Bell, "Coordination of the settings of phase-shifting transformers to minimize the cost of generation re-dispatch", in CIGRE Session 2014, 2014.
- L. Shen, M. Barnes, R. Preece, J.V. Milanovic, K.R.W. Bell, M. Belivanis, "Potential Interaction between VSC HVDC and STATCOM", in Power System Computation Conference, 2014.

8 At the time of writing according to the Google Scholar citation reporting service.

- L. Shen, M. Barnes, R. Preece, J.V. Milanovic, K.R.W. Bell, M. Belivanis, “The effect of VSC HVDC control and operating conditions on dynamic behavior of integrated AC/DC System”, in IEEE Trans. Power Delivery, 2015.

2 Power system operation, planning, economics and optimisation

In this chapter, background information about power system operation, planning, economics and optimisation is provided. The aim is to enable the reader to make better use of the material of the next chapters.

2.1 The Great Britain energy landscape

2.1.1 The electricity market arrangements

Great Britain operates under a liberalised framework as described in the New Electricity Trading Arrangements (NETA) Act. NETA is supplemented by the Electricity Market Reform that includes a new subsidy scheme for new renewable and low carbon generation as well as additional provisions for the security of supply[9]. A detailed description of the evolution of the GB market arrangements over the last decades can be found in [10]. The progress so far has set the basis for the introduction of competition in the development and ownership of solutions for the reinforcement of the transmission network at a future time [11].

As in other countries, the previously vertically organised function of power generation, transmission, distribution and supply, is performed by separate, regulated utilities each with its own roles and responsibilities. The role of networks ownership on land is separated to companies acting as Transmission Owners (TOs) and Distribution Network Owners/Operators (DNOs). In Great Britain there are three TO and fourteen DNO license areas[10] each responsible for a different geographic area. Ownership of the offshore networks – required to radially connect offshore wind farms – is covered by the Offshore Transmission Owner (OFTO) regime and the interconnectors to European Union (EU) countries are also privately owned. The National Grid Electricity System Operator (ESO) is the independent[11] System Operator (SO) of Great Britain.

Suppliers buy electricity directly from generators in order to meet the demand of their retail customers. The bulk of the transactions take place through bilateral agreements or forward and

9 These are the “Contract for Difference” (CfD) and “Capacity Market” schemes respectively. Under the CfD scheme, a “strike price” is agreed for the sale of electricity of eligible, low carbon generators. When a generator achieves a lower price in the wholesale market than the strike price, payments are made to the generator to cover the difference. When the generator achieves a higher price, they must return the excess profit to the payments counter party, the “Low Carbon Contracts Company” – that is government owned.
10 Note there are less than fourteen distribution network owners as one company can own and operate the network in more than one license area.
11 National Grid ESO is a legally separate entity although still part of the National Grid group.

future markets where volumes and prices are agreed long before the delivery time. The market participants can use trades in power exchanges to fine-tune their position. The exchanges run up to 1 hour before ("gate closure") the respective "trading period" – that itself is half an hour long. Following gate closure, participants can no longer change their market position. Any deviation from the agreed volume – due to resource availability, demand forecast error or any other reason – is considered in the "imbalance settlement" process that follows (Figure 2-1) [12][13].

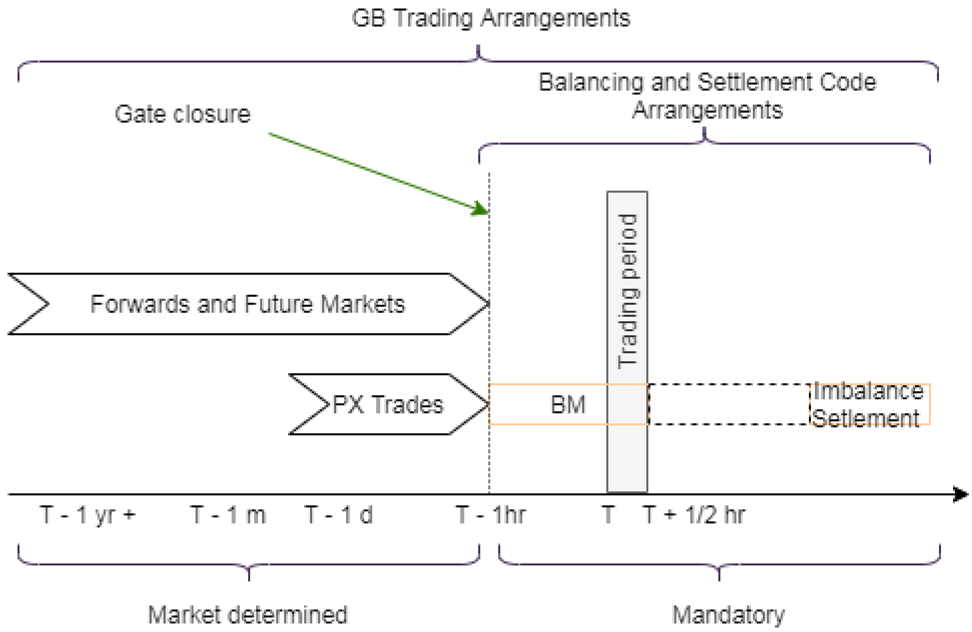

Figure 2-1: Summary of the GB electricity market arrangements. Source: [13]

The ESO must balance the system, manage restrictions in transmission transfer capacity[12] and make sure ancillary services are in place on a minute by minute basis. Balancing the system in practice means that generation in GB (and imports from interconnectors) must match the demand, export from interconnectors and expected power losses at the beginning of every trading period and that sufficient frequency containment services are in place to handle the intra trading period imbalances (and any generator contingencies) that may occur. For every trading period the Balancing Mechanism (BM) starts at gate closure and runs through to the end of the period. Generators and other BM participants (BMUs)[13] submit 'Bids' and 'Offers' to the ESO. A generator Bid is a proposal to reduce generation and an Offer a proposal to increase it[14]. The ESO 'accepts' Bids and Offers as required, essentially instructing BMUs to

12 Transmission transfer capacity is defined in section 2.2.2
13 Technically a BMU is the group of plant or apparatus that can be independently controlled. A BMU can be a single generating unit of a power station or a collection of consumption meters for instance.
14 For a demand BMU, a Bid is a proposal to increase demand and an Offer to reduce it.

re-dispatch to a specific output at a given time. It is mandatory for certain types of generators to participate in BM but no restriction exists for the Bid and Offer prices they propose.

The Balancing Mechanism is not the only means that the ESO can use to change the market position of a participant. Trading energy (not for profiting) or bilateral long(er) term constraint management contracts are also considered where appropriate [14]. Competitive markets and procurement processes are in place for ancillary services.

The point to note is that in the liberalised market environment in GB, generators, interconnectors and suppliers, all have the ability to decide the power they intend to generate, transfer or consume as well as the price they are willing to accept for it to be changed. The ESO is incentivised to manage the system in as an economic way as possible and the cost of the BM actions is recovered from transmission network users (generators, directly connected transmission demand and suppliers) through charges[15] and eventually from the consumers.

Although there is no regulation for the Bids and Offers generators submit to the BM, it can be said that, in a competitive market, they will reflect any loss or savings the generators are exposed to from the ESO instructions. As the ESO's Bids and Offers acceptances do not change a BM participant's "settled" position (payments for the energy transactions already agreed) any additional expenditures or savings will be the result of subsidies, charges or fuel cost being paid or not.

Renewable energy and low carbon generators receive additional income in the form of subsidies[16] for the energy they produce. The Bids they propose should reflect the loss of income from not receiving these subsidies. Thermal generators are exposed to carbon charges and fuel cost when they are producing energy. Their Bids reflect the savings of not having to pay these expenditures. Thermal generators' Bids are "positive" (revenue for the ESO) so they can help offset the overall balancing cost. Thermal generator Offers reflect the additional expenditure from increasing their output – the cost of fuel, carbon charges as well as the opportunity cost from energy not being sold.

Reference [12] provides more information about the electricity trading arrangements. The "BM reports" service [15] records the actual Bids and Offers submitted and other market related data. The ESO "Monthly Balancing Services Summary" breaks down the overall cost of operating the network to that of managing constraints and of other services in each month

15 In GB these are the Balancing Services Use of System charges [197].
16 Subsidies take the form of Renewable Obligation Certificates (introduced in NETTA) or Contracts for Difference (introduced in the Electricity Market Reform). Although the subsidy for the generator is calculated differently the principle of how they affect Bid prices is the same.

[16]. Reference [17] explains how the BM generation re-dispatch cost is used as a proxy for the cost of operating the network in investment planning studies.

2.1.2 Generation connections and access to the transmission system

In the liberalised environment the investment in transmission capacity and in generation capacity are carried out by different entities and coordination between the two must be achieved through the network development process, market measures (such as zonal connection charges), through regulation or government intervention in certain occasions. In GB, certain large power stations, offshore wind farms or interconnectors must undergo a connection process that examines multiple connection locations as part of their connection application[17]. Further, zones for offshore renewable development are centrally allocated to prospective developers by the government [18]. Other than the above, developers of generation projects are, for the most part, able to choose when and where they wish to apply to connect to the networks or when to decommission existing generation stations.

The 'Connect and Manage' scheme was introduced in 2009 in order to accelerate renewable energy connections [19]. Previously, the 'Invest and Connect' scheme stated that reinforcement works on the wider transmission system that – at the time of the application – were associated with a new generator connection[18] in order for the network to be compliant with the generation connection criteria and the main interconnected system design criteria outlined in the security standard[19] had to be completed in their entirety before the generator was allowed to connect. It was recognised that renewable energy generators over a broader region do not all always operate at a high capacity factor simultaneously and that the existing network capacity, designed with deterministic criteria for meeting[20] winter peak demand, could be sufficient in other periods of the year. Further, any delay to the delivery of the transmission reinforcements would result in a delay in the generator connection. 'Connect and Manage' would allow a new generator to connect on a 'non-firm' basis as soon as a reduced set of the associated work were completed and so effectively "share" the existing main interconnected system's capacity with the already connected ones [20].

There are some differences in how a generator with firm and one with non-firm connection can be used by the ESO for constraint management that are beyond the scope of this work. Further, since the exact commercial arrangements of non-firm generators are case specific and

17 At the time of writing this is the "Connections and Infrastructure Options Note (CION) Process" [198] that is due to be superseded by provisions currently under consultation as part of the "Offshore Transmission Network Review (OTNR)" [199].
18 Broadly categorised as user-specific infrastructure works or wider infrastructure works
19 SQSS [4] section 2 – "Generation connection criteria applicable to the onshore transmission system" and section 4 – "Design of the main interconnected transmission system.
20 Meeting with a predefined level of economy and reliability – see section 2.2.1

depend on the delivery of certain network reinforcements (that are different for each generator) and are subject to change when the expected reinforcements are delivered, these commercial arrangements will not be part of the analysis presented in Chapter 5.

While the Connect and Manage scheme made it possible for more renewable generation to connect than it would have been the case otherwise, it was understood that generation connections could outpace the delivery of new transmission reinforcement works. That in turn could lead to increased cost for operating the network, at least in the short term, albeit with expected socioeconomic benefits in terms of the cost of energy and carbon emissions [21].

2.1.3 The net zero ambition

To mitigate the worst impacts of the ongoing climate change, a combined effort to reduce greenhouse gas emissions and to extract some of the carbon already released in the atmosphere is necessary. In GB, the power sector is leading the way in meeting the targets set in the Climate Change Act by reducing the emissions associated with the production of electricity and by enabling other sectors of the economy – such as heating and transport – to transition to more carbon efficient technologies [22].

As of 2021, the UK government is committed to a fully decarbonised electricity system by 2035. That will require an additional 40GW[21] offshore wind by 2030 as well as, according to the independent assessment of the UK's net zero strategy published by the Climate Change Committee in the same year [22], various amounts of other low carbon generation technologies such as nuclear and hydrogen.

There is more than one pathway to meet the net zero ambition as there are many uses of energy and where it is coming from can change. The ESO publishes four "scenarios" that represent credible future outcomes for the energy sector as a whole every year in the "Future Energy Scenarios" (FES) publication. They are a result of modelling, research and stakeholder engagement and find many uses across the industry. To that respect, the FES team organises industry consultation sessions throughout the year where industry stakeholders can provide insight, evidence and feedback. Further, prospective generation capacity providers can use FES as a guide for the amount and location of the different types of generation the ESO anticipates to connect on the network under the different scenarios/possible future outcomes [23]. One of ESO internal uses of FES is to inform the network development process and to help manage uncertainty (see section 2.2.6). Further info regarding FES is provided where necessary in this document.

21 The offshore wind target was increased to 50 GW in the UK Government's energy security strategy published in April 2022.

2.2 Power system operation and planning

2.2.1 The link between day-to-day operation, long term planning and the reliability standards

Operating the power system at present time and planning for operation at future times can be thought at a series of sub-problems or stages that take place on different time horizons Figure 2-2 – adapted from [24] – breaks down the overall problem into three stages: investment planning, operational planning and asset management, and system operation[22]. Although the inputs, the methods or the standards that apply to each stage appear to be different, they are closely linked as the output of each stage is an input to the next one and they are all underpinned by a common, overarching objective. Uncertainties or disturbances related to market forces and regulation are not explicitly displayed in Figure 2-2 for brevity but can be found in [25].

It can be seen how each stage acts as a facilitator for the ones that follows. Infrastructure decided on in investment planning will be put into use during system operation at future times. If the infrastructure is not in place, future system operation with the same levels of economy and reliability as those of present time will probably not be possible. On the other hand, for the long term planning process to be able to enhance or maintain economy and reliability to the present levels, the planning standards and methods that apply must be consistent with those of system operation. So it is a two-way relationship. The electricity system is planned with the same principles that apply during operation. How the system was planned determines how it can be operated.

22 Investment planning is often called transmission expansion planning, network development or simply long term planning. By extension, operational planning is often called short term planning. Operational planning for the most part covers the timeframe from one day to a year ahead of present time. In certain cases, there could be some overlap in terms of timescales or deliverables. Specific asset management activities need to be planned further than a year ahead into the future. Operational planning and (preparing for) operation eventually merge at the day-ahead and intraday [200].

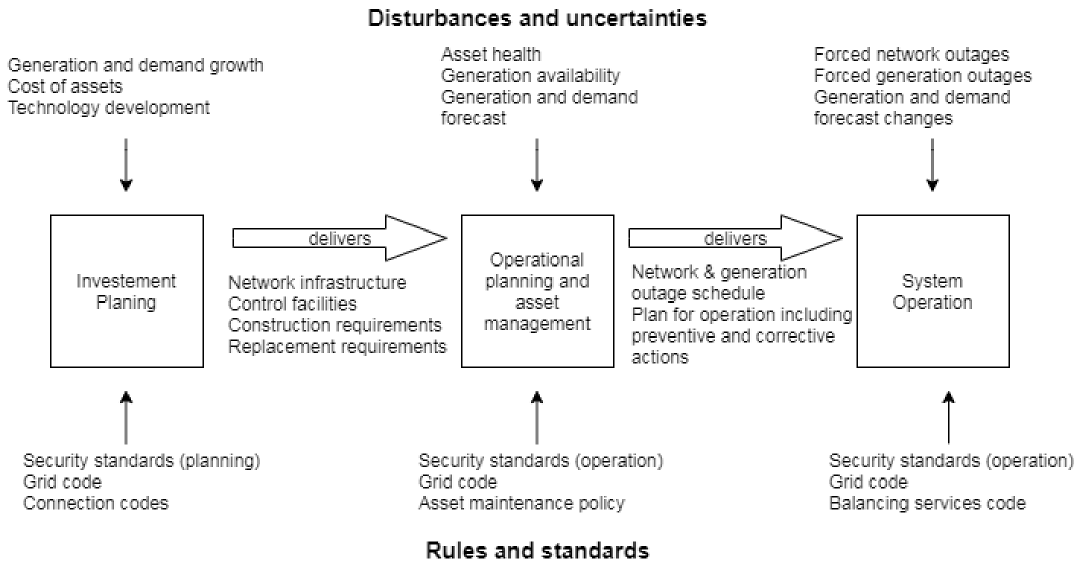

Figure 2-2: The link between system operation and long term planning. Source: [24]

This separation to the stages of Figure 2-2 is necessary as the lead time for the implementation of the outputs or decisions of each stage is different. Transmission reinforcement works can take up to several years to design, plan, consent with the public and planning bodies and deliver and they require substantial monetary investment [1]. At shorter timescales, certain operational measures have to be agreed or contracted ahead of time to be available on the day of operation. Another reason is the uncertainties experienced in each time horizon [26].

The common objective is to plan and operate the system in an economically efficient manner, while maintaining, at least, an ‘adequate’ (or agreed upon) level of reliability [27]. The overall cost can be generally broken down to the cost of infrastructure (I) and that of operation (O) [24]. The cost of infrastructure includes the investment required for new reinforcement works as well as the cost of maintaining the existing assets. By delivering reinforcement and increasing the network transmission transfer capacity (see section 2.2.2) it is expected that the cost of operating the network – section 4.2.2 – reduces. As both activities correspond to expenditure and, transmission reinforcement works can only be delivered in “large” discrete steps [28][23], increasing transmission capacity above a certain level may not result to the least overall cost. Instead, a balance between the two aspects of cost that minimises the combined cost must be found.

23 See Chapter 8 of reference [28] – “Investment in transmission”

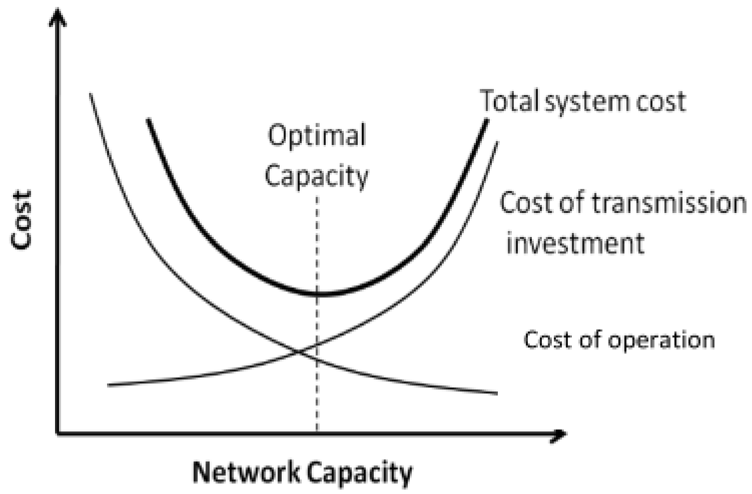

Figure 2-3: Maximising consumer benefit by minimising total system cost. Source: [29]

Figure 2-3[24] [29] graphically demonstrates that. It can be seen there is a point in the graph where the overall system cost is minimised. That is the level of investment in transmission capacity that provides the most benefit for the consumers (economics driven capability [27]). Investing in transmission capacity beyond that point is not a cost-effective way to reduce the cost of operation. The additional cost of investment will exceed additional reduction in operation cost and the overall system cost will increase.

Reliability is the ability of the power system to supply consumers: to be able to meet their aggregated demand ('adequacy') and to withstand disturbances ('operating reliability' or 'security') that will occur [30]. Although there are many aspects of reliability (not all of them related to transmission network capacity) and more than one way to quantify it [27], it is expected that the 'high enough' reliability results in 'sufficiently' low expectation of service interruption [31].

The security (reliability) standards [4],[32] underpin all stages and provide a consistent set of provisions and criteria for the SOs and TOs to develop and operate the power system. In GB the "Security and Quality of Supply Standard" (SQSS) [4] is the security standard that applies.

Two criteria defined in SQSS are the deterministic 'N-1' and 'N-D' security criteria. SQSS states that an unplanned, forced outage because of a short-circuit fault (i.e. a "contingency") should not cause any piece of equipment to exceed pre-specified current or voltage limits or

24 Note in a real power system the lines of the Figure 2-3 take a piece-wise linear form. As transmission reinforcement works can only be delivered in "large" discrete steps so is the investment cost the incur and the reduction in operating cost they offer.

cause other unwanted phenomena such as ‘unacceptable’ loss of supply and frequency deviation or system instability. The ‘N-1’ and ‘N-D’ criteria are used to define which unplanned outage events should be considered as contingencies[25].

The ‘N-1’ criterion is defined in different ways in different countries [6]. It could be about a forced outage of a single circuit or of a single generator for instance or, in other cases, a single event such as the forced outage of a pylon carrying a double circuit or that of a busbar section. In GB, it refers to a forced outage of a single circuit (“singe-circuit” fault) or generator (including generation sharing a common connection to the network or protection equipment) or that of a section of a busbar. In GB, the ‘N-D’ criterion refers to the simultaneously forced outage of both transmission circuits that are suspended on either side of a transmission tower (i.e. a “double circuit” fault)[26].

Having both the ‘N-1’ and ‘N-D’ criteria in the standard, the GB network must be secured against both single-circuit and double-circuit faults (for the TO areas and type of consequences that the latter applies) at all times.

The SQSS also provides the criteria for assessing the present time transmission transfer capacity of an area of the network (transmission boundary – see section 2.2.2) and to determine what the required (stipulated) level of capacity is (‘Required Transfer’ – section 2.2.2). In GB investment in transmission works should be planned to meet at least that level of transmission capacity (reliability driven capability [27]).

With all their provisions, the standards effectively provide a pathway for operating and planning the power system with an adequate, pre-defined level of reliability. Although the set of rules and criteria of the standards are now set, the process for defining them included risk modelling, analysis of historic operational data or, at times, quantification of the expected cost of (un)reliability as required [33]. Further, the standards can be adaptive in response to the prevailing conditions that the system is experiencing. In the case of ‘adverse’ conditions, SQSS allows some deviation from the criteria defined for ‘normal’ conditions.

Whilst the SQSS stipulates the level of transmission transfer capacity that the different areas of the GB transmissions system must meet, economic justification of the planned reinforcement works is still required for a number of reasons (Appendix G of [4] and section 2.2.6). One of reasons is that there is more than one set of reinforcement works that can meet

25 There is further detail about how the criteria must be applied for the different type of consequences and TO areas in [4] that is beyond the scope of this document.
26 There are specifications for when two circuits suspended on the same set of towers can be considered a double circuit such as tower spans or circuit length shared.

the Required Transfer of an area at a given future time. Each comes with a different investment cost, lead-time and impact on the cost of operating the network. SO planning processes should be able to select the set of works amongst them that provides the highest consumer benefit. At times, it may be more economically efficient to plan for a level of transmission transfer capacity higher than the Required Transfer for specific areas as the additional investment results in a decrease of the overall cost. Finally, the SQSS criteria were defined for a given set of prevailing conditions[27]. Planning processes should account for a wider range of prevailing conditions like the ones expected to occur over the course of a year.

2.2.2 Transmission transfer capacity and network boundaries

A transmission boundary is an imaginary line that crosses certain transmission circuits and splits the network into two distinct areas. In Great Britain it finds uses both in short term (Figure 2-5) and long term (Figure 2-7) planning.

Boundaries are used to determine the ‘transmission transfer capacity’ (TTC) – also called capability – between two adjacent regions of the network. That is, the amount of power that network can transfer from one region to the next while meeting the criteria of the security standard (SQSS). The boundary capability is in effect a measure of the performance of the transmission network in that area.

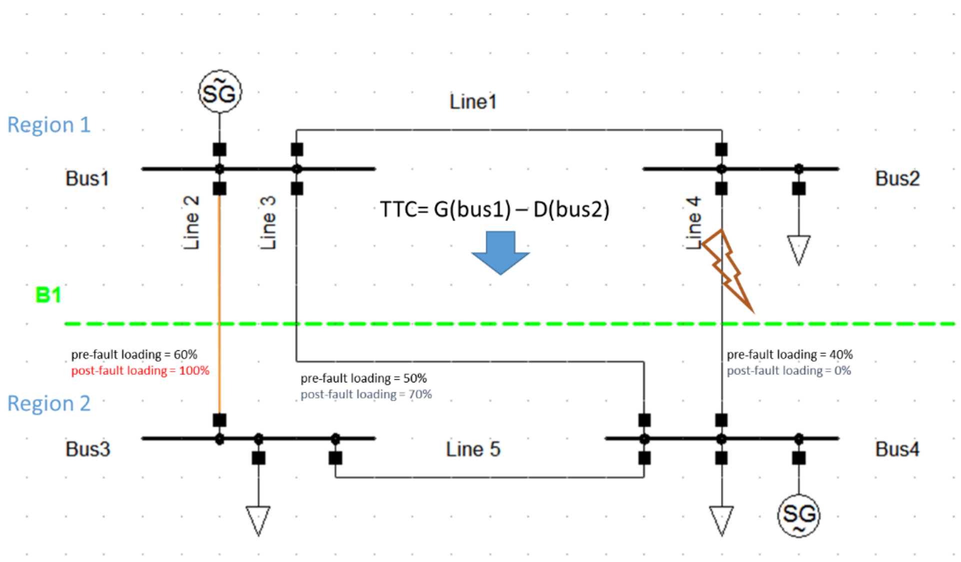

Figure 2-4: Example of a transmission boundary and of boundary capability

The transmission transfer capacity is lower than the sum of the capacities of the individual circuits that cross a boundary (Figure 2-4) as SQSS stipulates that the network must be able to

27 Specifically, for the level of transmission transfer capacity to meet reliably the winter peak demand.

withstand a set of pre-defined events while avoiding certain consequences. In the example of Figure 2-4, the event would be the unplanned short-circuit fault[28] (contingency) of one of the circuits crossing the boundary and the consequence would be that one or more of the remaining circuits reaches its capacity. It can be seen that, for a given transfer level and sharing of flows between the three circuits crossing the boundary, the contingency of Line 4 causes Line 2 to load up to 100% of its capacity[29]. The combination of limiting component and contingency restricts the amount of power that can be "securely" transferred across the boundary and sets its capability: the net of the generation and demand of buses 1 and 2[30]. The limiting component could be the circuit of lowest capacity but that also depends on the operating conditions and the resulting sharing of flows on all three circuits – both before and after the fault.

If the amount of power that can be securely transferred across a network boundary and the contingency that limits it are known, a plan of actions can be prepared that will be applied if the amount of power is exceeded and/or if the contingency happens. This one of the ways the ESO can use to plan for the network operation in the short term [34].

Figure 2-5 [34] presents the example of the boundaries that needed to be considered for preventive or corrective actions during short-term planning in a specific day of the year. For each of these boundaries a TTC was calculated and a plan of preventive and/or corrective actions was prepared for the event that the flow through any of these boundaries would exceed the calculated TTC or a contingency of one of the circuits crossing the boundary would happen. In that particular day, only the drawn boundaries would require actions. It was established that the TTC of other boundaries would be sufficient or that preventive actions on the existing boundaries would suffice to secure other ones (by also reducing flows through downstream boundaries for instance). So the boundaries drawn are the ones that would capture the 'binding' constraints on that particular day and operating conditions. As the operating conditions change over the course of a year – due to generation availability and planned outages for instance – so do the boundaries that need to be considered for preventive or corrective actions in short term planning. An assessment of all network areas and contingencies takes place in order to establish the boundaries that must be considered for a particular day/operating conditions.

28 We consider permanent fault outages only i.e. when the transmission line cannot return to service immediately after the fault is cleared.

29 In the example we assume that region 1 is the "exporting" region, where generation exceeds demand. Further, for calculating the capability we assume a contingency in Line 2 or Line 3 does not cause the flow in any of the remaining circuits to reach or exceed their respective capacity.

30 Adjusted for losses if applicable.

The image of Figure 2-5 has been removed by the author for copyright reasons. It can be found in page 13 of referecne [34].

Figure 2-5: Part of the transmission network of England and Wales with some boundaries used in operational planning. Source: [34]

Boundaries are also used to set the requirement for the long term reinforcement of the transmission system. The ESO publishes the System Requirements Form (SRF) – Figure 2-6 – annually as part of the Electricity Ten Year Statement (ETYS) process. Figure 2-6 is an example of an SRF graph for one of the GB transmission boundaries as published in 2020. A separate graph is published for each tranmsission boundary used in long-term planning (Figure 2-7) and Future Energy Scenario (FES) [35][31].

31 Reference [35] explains how to interpret the SRF graphs and includes the graphs for other scenarios and boundaries.

The graph brings together the following information: the current boundary capability (i.e. boundary capability in 2020[32] in the case of Figure 2-6 – black line); a forecast of the expected flows through the boundary in the next 20 years (that are produced by a year-round economic dispatch calculation – light green and dark green shaded areas); and the Required Transfer (RT) in each of the next 20 years (the capability that the boundary must meet according to the SQSS design criteria – solid green and dashed green lines).

The image of Figure 2-6 has been removed by the author for copyright reasons. It can be found in sheet "B8" of referecne [35].

Figure 2-6: System requirement form for boundary B8 in the Leading the Way Future Energy Scenario in 2020. Source: [35]

The Required Transfer can be defined using either the "Security Planned Transfer" and "Interconnection Allowance" or the "Economy Planned Transfer" and "Boundary Allowance" methodologies of SQSS (hence "Security RT" and "Economy RT" in Figure 2-6). The Security and Economy methodologies describe two alternative ways to dispatch the installed generation to meet winter peak demand in each FES scenario and considered year using a fixed set of assumptions and scaling factors. The main difference between the two is the treatment of renewable/variable and thermal generation. The objective of the Security Planned Transfer methodology is to provide the expected flow through each boundary in a scenario where thermal generation is primarily used to cover the peak demand[33] and that of the Economy one

32 Note that only the present year (i.e. the calendar year of the SRF graph publication, in this case, 2020) boundary capability is shown in the black, straight line. Future capability in GB will be higher because of reinforcements already scheduled to be delivered that will increase the capability of the boundary in the future. However, this is not shown here as the purpose of the graph is to inform of the difference between present day capability and future requirement (as explained in the remainder of this section) and is used as part of the network development process that selects, schedules and re-confirms the eligibility of the aforementioned reinforcements (introduced in section 2.2.6).

33 In the Security Planned Transfer methodology renewable generation does not contribute to meeting peak demand. Planning the network so that the boundaries have sufficient capability to meet the Security Required Transfer (that is derived from the Security Planned Transfer) means that, in the event of peak demand and low renewable energy output, network boundaries will have sufficient capability to accommodate the resulting power flows and the security of supply will not be compromised by network limitations – hence the term "security" in the name of this criterion.

in a scenario that resembles more the operation of the market. An additional margin is added to the Security and Economy Planned Transfers to come up with the reported Required Transfers value of Figure 2-6. The margin is calculated using the “Interconnection” and “Boundary” allowance method respectively.

In practice, the three measures of system performance included in the SRF graph (the economic dispatch forecasted flow, the Security Required Transfer and the Economy Required Transfer) are all used to set the ‘requirement’ for boundary reinforcement – i.e. the difference between present time capability and future flows. Where the Security or the Economy Required Transfer predicts more onerous flows than the other, it is the one used, as reinforcing the boundary to meet the more onerous case is sufficient for it to meet the least onerous one. Where the economic dispatch forecasted flows indicated a volume of flows higher than that of the Required Transfer, they are used as an indication of the future boundary capability that must be met instead of the Required Transfer (that is confirmed through the network development process described in section 2.2.6).

In GB, the TOs are obliged by their license to provide a network where boundaries meet at least the Required Transfer conditions [34]. That means that the TOs must propose to the ESO future transmission reinforcement options that increase the present time capability (section 2.2.3) to at least the Required Transfer level. The ESO then is able to select the preferred combination of options as part of the network development process (section 2.2.6).

So, in long-term planning, boundaries are used to compare network reinforcement options on a common technical basis: the additional TTC/capability they provide (section 2.2.3). Since every option provides a different amount of TTC with a given lead time and investment cost, the boundaries are also used to compare their economic performance: how the reduction of operating cost an option makes possible over its lifetime compares with the investment cost required to deliver it.

Boundaries are useful if they “capture” the limiting component and contingency of each area of the network. In practice, that requires that both the component and the contingency cross the boundary or are within its vicinity. Boundaries must be redefined as operating conditions or the underlying network structure changes – because of new generation connections, generation closures, demand changes or network upgrades in the long term. So an assessment is required at the beginning of each annual long term planning circle to establish the specific boundaries that need to be considered and the future study years that each will be used in.

34 Derogations and exceptions to this obligation are outside the scope of this document.

The image of Figure 2-7 has been removed by the author for copyright reasons. It can be found in Appendix A (Figure A3) of reference [9].

Figure 2-7: An overview of the GB transmission system with the boundaries used in long term planning. Source: [9]

2.2.3 Increasing transmission transfer capacity

This section will briefly introduce some of the available options for increasing transmission transfer capacity. Using the boundary example of Figure 2-4, it was observed that one of the branches crossing the boundary is the first to reach its capacity limit following a contingency of one of the other branches. It follows that there are four ways, in principle, to increase the transfer capacity of the boundary:

1. Power flow control or other measures that change the sharing of flow across the branches crossing the boundary and/or are able to divert power away from the limiting component – before or after the contingency.
2. Topological actions that change the network structure in a way that reduces the power flow through the limiting component. Actions may change the running arrangements of substations (i.e. the way the busbar sections that transmission branches are connected to are linked to each other) or even remove the limiting component from service (before or after a contingency) altogether – provided that the remaining branches provide sufficient capacity and no loss of supply is caused by it.
3. Transmission reinforcement works that increase the capacity of the limiting component.
4. Transmission reinforcement works that provide new transmission routes out of the exporting region.

Active power control

Control of active power can be achieved by altering the voltage angle of the network nodes on either end of a branch or by altering the impedance of the branch (Ap. 1). Changing the power injected or withdrawn by generators or demands by accepting Bids and Offers in the Balancing Mechanism (that will in turn affect the voltage angles at the power flow solution) is one way the ESO can use control the power flows through network branches. Alternatively, power flow control devices – that fall under the broader category of "Flexible AC Transmission" (FACT) controllers [36] – can be used. There many types of power control devices each based on a different technology and having different control capabilities but, in principle, relying on the methods mentioned above. Chapter 3 of reference [37] categorises the various power flow control devices based on their principle of operation, their connection to the network and other criteria and provides a detailed overview of how each works.

A phase-shifting transformer (PST) is a power control device used by various TSOs in Europe and around the world. Details on earlier experience of PST use in central Europe can be found in references [38] (German-Dutch border), [39] (German – Polish – Czech border) where they have been used to control unscheduled loop flows (see also section 3.5). References [40], [41] (Italy), [42] (France) and [43] (Ireland) provide background on the experience of use of PSTs in these systems. PSTs can also prove useful in the case of less developed power systems or when the interconnection between countries has to be accomplished through circuits of varying capacity or of different voltage levels. Examples of these applications can be found in references [44] (Zambia - Zimbabwe interconnection) and [45] (Iraq with neighbouring countries). Further, an application not only related with power flow control, can be found in reference [46] where PSTs installed in series with reactors in Canada (to limit fault current and extent the range of control capability) can also be used to assist substation uprating, sharing of reserves and even transmission line de-icing.

In the following we will focus on the use of PSTs in the context of a meshed transmission network where multiple circuits are crossing the wider transmission boundaries as in the GB network. A Quadrature Booster transformer (QB) is a special type of PST used in GB. Appendix A: QB technology of this document provides detailed technical information about them.

Going back to the boundary example, Figure 2-8 draws the boundary of Figure 2-4 with the addition of one QB in series with Line 2, the boundary limiting component. The QB can be used to change the sharing of flow across the three lines of the boundary. In this instance, the QB is used to "block" power through Line 2[35] which will result in more power flowing through Lines 3 and 4. For the same transfer level as before (effectively a given set of injections from generator and loads in the network nodes), the contingency of Line 4 no longer results in the Line 2 reaching 100% of its capacity. More power can now be securely transferred through the boundary.

35 The impact of a QB action is most noticeable in the branch the QB is installed in series with. However, QBs can have an impact on the power flows of a broader area of the network especially when multiple devices are used in coordination as we will soon see.

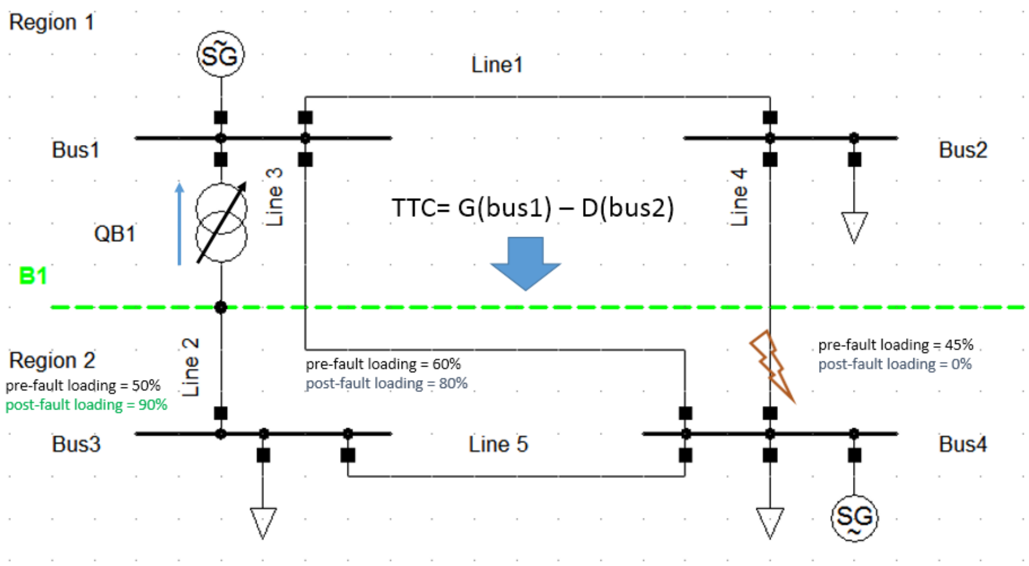

Figure 2-8: Increasing transmission transfer capacity with the use of QBs

In this example the QB was used to change the power flows before the contingency so that no adverse conditions are to be expected if the contingency takes place. The QB was used for a preventive action. The same outcome can be had if the QB is used after the contingency to divert power away from Line 2 and avoid an enduring overload – provided that the QB actions can be completed reasonably quickly. In that case the QB would be used for a corrective action ([7] and section 4.3.2).

Transmission reinforcements works

Transmission reinforcement works can upgrade or replace certain components of the boundary limiting branch in order to increase its capacity. If more TTC is required a new AC transmission route out of region 1 and through the boundary can be considered.

The new route (Line 6 – Figure 2-9) will change the network structure and will re-distribute the power flows across all four circuits now crossing the boundary before the contingency. It will also add a new route for the power to flow following the contingency of Line 4. This will result in the portion of the flow attributed to the limiting component, Line 2, before the contingency, following the contingency or, in both occasions, to be less than it would have been otherwise. In the case of a new AC overhead line (OHL) the design of the new line (capacity and connection points) must ensure that the above is achieved.

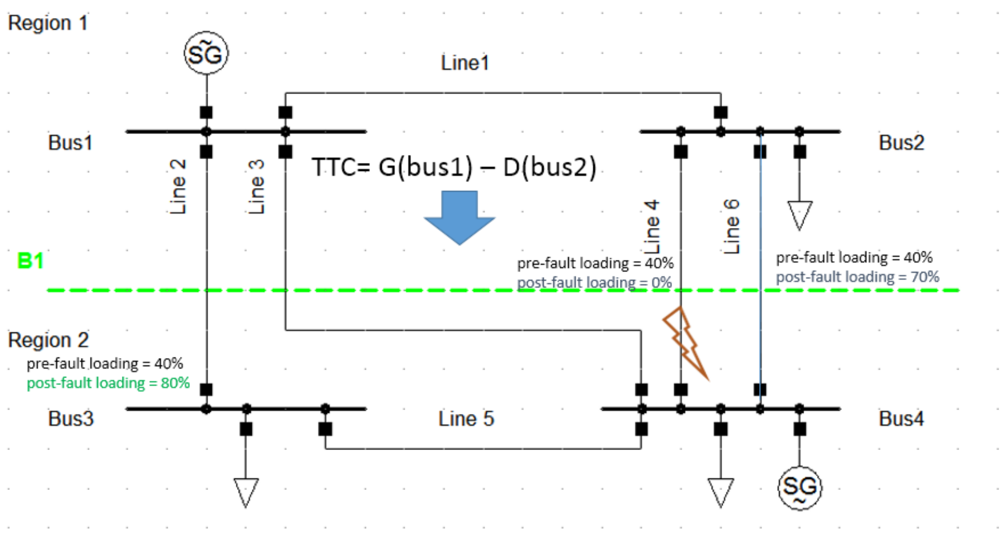

Figure 2-9: Increasing transmission transfer capacity with a new transmission circuit

Reference [47] notes the "investment paradox"[36] where if a new OHL line is not properly designed, it can actually increase the flow through a set of circuits. That could reduce how effective the line is in increasing the transmission transfer capacity and it may require that power flow control devices are installed as well.

The various types of transmission reinforcement works and further options for increasing the boundary transfer capacity that are considered in GB can be found in Chapter 2 of reference [48].

2.2.4 Use of phase shifting transformers in GB

There are currently 13 QB devices installed in the 400 kV transmission system of England and Wales. Ten of the devices can be found in pairs i.e. on both branches of a double circuit. The paired QBs must generally operate with the same or similar tap setting to avoid creating loop flows or uneven loading on the two branches of the circuit. The QBs can be separated into four groups, each influencing the flows through the circuits of the respective area: "east", "west", "central" and "south coast" [9].

When QBs are used in coordination they are able to exercise control over a broader area of the network. The "east", "west" and "central" QBs, when used together, can influence the sharing of flows across the circuits that bring power from the northern areas of the country towards

36 The reference notes this with respect to the increase of loop flows (unwanted flows) through an area. An easy way to understand this is that a second, parallel line between Bus 1 and Bus 2 would reduce the impedance of the combined bus 1 to bus 2 route thus driving more power through the west side of the boundary. Although the west side of the boundary is where the limiting component is located it could be that the best design for an OHL is to be on the east side.

the southern (Figure 2-10 – adapted from [3]). The devices in the "south coast" group can be used to balance the flows on 400 kV and 275 kV parallel circuits in the London area [3] [8].

During preventive (pre-fault) operation the QBs are generally operated close to their neutral tap setting in order to maximise their dynamic range. When the SO engineers calculate corrective (post-fault) actions for the control room during operational planning, the use of QBs located at a single site only (one QB or one pair) is assumed [8].

In GB at the time of the writing, QB actions are manually executed and there is no automated, event based or close loop control. Two reasons identified in [8] and in [49] are the difficulty of the QB device controller to reliably know that a fault has happened and what is the correct short-term thermal rating that applies as well as the interactions between sites. The topic is discussed further in section 4.2.1.

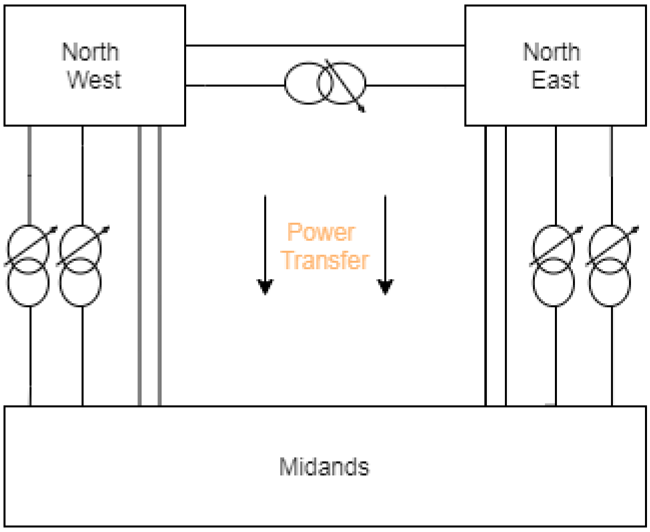

Figure 2-10: Use of QBs to control utilisation of North to Midlands citcuits. Source: adapted from [3]

The installation of additional QB devices is considered as an option for increasing the TTC of a boundary (on its own or together with other reinforcements) during transmission expansion planning (section 2.2.6) and can be selected on not based on the balance between investment cost and the increase in TTC they provide [48].

Further discussion

Power flow control devices effectively allow better use to be made of the existing network capacity. In Figure 2-8, through the QB action the capacity of all three circuits is more evenly utilised. This allows more power to be securely transferred through the area than would have been possible otherwise at no additional cost. Procurement of power flow control devices (as well as the associated substation works and the communication and control hardware necessary) come with a certain investment cost but that is lower than a number of other transmission reinforcement works. (Appendix E of reference [50] provides an indicative cost figure for various types of transmission reinforcement works).

Further, once installed, QBs and other power flow control devices can be actively controlled and used to influence power flows on branches further away from the branches they are installed in series with. Such flexibility can be used under multiple operating conditions and for a number of different areas/boundaries (contingencies).

When operating a power system with many power flow control devices or devices that can influence the flows on distant areas of the network issue of coordination of their settings arises. In the previous discussion, we presented the example of a QB that was used to increase the transfer capacity of a single boundary (Figure 2-8) and explained how multiple QBs can be used for the same purpose (Figure 2-10). As the network compromises of many areas/boundaries, it can be said that finding a set of preventive tap settings that are "optimal" (i.e. maximise transmission transfer capacity) for a specific boundary (set of contingencies) is not guaranteed to be optimal for any of the other boundaries or to be the ones that provide the minimum cost operation of the network [2], [51]. The topic of coordination of tap setting is discussed more in the following chapters.

2.2.5 Thermal, voltage and stability transfer capacity restrictions

In the previous discussion we used the example of branch capacity as the factor that limits the boundary transfer capacity. In practice further restrictions must be considered in operation and planning [52]. The boundary transfer capacity concept can be straightforwardly used to model the following three restrictions:

- Thermal: when the ability of a branch element (overhead line, cable, transformer) to carry current is exceeded. The amount of power that a branch element can transfer at any given moment depends on its ability to sustain or dissipate heat, hence "thermal" [53]. In the case of overhead lines, environmental factors (ambient temperature and wind) affect how much heat can be naturally dissipated so the actual thermal limit has a seasonal variation ('seasonal' thermal rating) and an intraday variation ('dynamic' rating). The capacity of an overhead line is eventually limited by the clearance between the conductors and the ground or other obstacles. As the loading of a line increases the conductors expand and the clearance below the line decreases. The expansion is a slow phenomenon which allows the "default" or 'continuous' rating to be exceeded for a short period of time if necessary (‘short-term’ thermal ratings). Transformers and cables are less exposed to environmental factors and their heat dissipation can be aided by mechanical means. They too exhibit seasonal variation of their thermal ratings and have some ability to be loaded above their ‘continuous’ rating. In certain occasions, the overall rating of a transmission branch can be limited by equipment not listed above, such as the circuit breakers or other substation equipment connected in series with them. If that is the case, the overall branch short-term rating cannot exceed the limit set by that non-conductor element. More information about how short-term thermal ratings are used in the GB transmission system can be found in references [34] and [8] (also in section 4.3.2). References [54] [55] and in [56] provide further information about how dynamic thermal ratings can be defined and their applications.

- Voltage: when a substation busbar (or one of certain other substation components) exceeds its defined upper or lower voltage limit before or after a contingency. The voltage limits that apply are specified in the security standards.
- Stability: when a contingency would result in the system entering an unstable condition. One example is that of generators not maintaining synchronisation with the grid (rotor angle stability) after the disturbance caused by a branch contingency but a stability limit on the boundary flow can be set due to other instability phenomena. Unlike the previous two, finding the stability limit requires time domain simulations. Stability is usually an issue with specific areas and operating conditions.

The above phenomena are not separable as current and voltage limits of equipment must be enforced at the same time and a new overhead line could improve the voltage or stability performance of the network in addition to providing “thermal” capability, for instance. However, the separation of network restrictions to thermal, voltage and stability helps to establish the notion that during operation, for thermal or voltage constraints, active or reactive power control actions should be sought after respectively.

2.2.6 Network development in Great Britain

One of the main processes the ESO uses to guide the **transmission expansion planning** in GB is the annual **Network Options Assessment** (NOA) [1] [57]. Through NOA, the ESO provides recommendations to TOs regarding where and when to invest in options that increase transmission transfer capacity in the next decade. It considers, for the most part, transmission reinforcement works (NOA options) that cover the long term thermal requirement of the transmission network that is a result of the bulk power flows through the wider transmission boundaries (Figure 2-7).

Following the publication of the System Requirement Form (Figure 2-6) for the boundaries used in long term planning (Figure 2-7) each year, the TOs submit options that meet the boundary requirement (i.e. that bridge the gap between the present time TTC and future boundary flows). TOs submit several options for each boundary that can be alternatives or complement each other in terms of how they provide TTC. NOA selects the preferred options and provides a recommendation for the ones that require investment in the next financial year as explained in the following. This process is repeated annually so options selected in the previous years are reconfirmed and their recommendation or the preferred delivery year is re-adjusted based on the latest information. Repeating the process also allows improved or alternative options to be selected, if they are found to provide more consumer benefit, when they become available.

The NOA process selects the subset of transmission reinforcement works that, when considered together, provide the highest consumer benefit (Figure 2-3). This selection is called the 'optimal path' and it separates the 'optimal' works from the wider set of candidate works that the TOs submit for evaluation. The selection takes place using technical studies (boundary TTC assessment) and cost benefit analysis where the reduction in constraint cost due to the additional TTC an option provides to a boundary, is compared to the investment required to deliver it. The assessment considers all the established transmission boundaries of the network (Figure 2-7) at the same time. That way, interactions between the TTC of each boundary, the cost of reinforcing it and the incurred constrained cost are all taken into account. Further, as certain options may be alternatives or may be used together to increase the TTC of a boundary even further, the boundary TTC assessment studies capture the interactions between the options by considering them as alternatives or studying them in combinations as required. As part of the selection process of this stage, the 'required' delivery year of each 'optimal' option is also decided [58].

The process must be robust against future changes and must not expose the consumer to undue financial risk (by overinvesting or underinvesting in transmission capacity). To achieve this, first, all four FES scenarios, that cover a range of possible future outcomes, are considered – instead of a single best view of the future generation and demand outrun. The selection process described in the previous paragraph is repeated for each FES scenario i.e. four 'optimal paths' are produced. Second, the process is repeated annually to adjust for changes or developments that took place since the previous NOA iteration. As a result, TOs are only expected to proceed with investment planned in "year 1" (the financial year following the NOA publication in January) for the options found 'optimal' before the next NOA cycle. Actions/investment required in the following years would be re-assessed in the next NOA iteration. Third, Least Worst Regret (LWR) in used to come up with a year 1 investment recommendation when the FES scenarios do not produce the same result for certain options as explained in the following.

Investment in year 1 could be necessary if the 'required' delivery year of an option is year1 or if the 'required' year is further into the future but investment in year 1 is still necessary in order for it to be delivered by then. These type of options are called 'critical'[37]. As four FES scenarios are considered (four 'optimal paths') certain options could be 'critical' in the 'optimal path' of one scenario but not in others. In order to reach a single decision whether investment in year 1 is the best course of action for each 'critical' option when there is a discrepancy in the 'required' years between the scenarios, single year regret analysis (min-max regret, also called Least Worst Regret) is employed. That ensures a 'risk-neutral' investment strategy (a recommendation whether to "proceed" with year 1 investment for each 'critical' option or not) across the scenarios.

Applying the actions (investment) of the year 1 and re-evaluating the actions for the following years in the next NOA iteration is akin to a receding horizon, Model Predictive Control (MPC) scheme where an optimisation problem is solved over a multi-year optimisation horizon but only the first time-step of the output is applied. The process is repeated in the next year with the optimisation horizon increasing by one year/time-step into the future. In effect, the process uses the most up to date information at any given time and takes advantage of the decrease in uncertainty as our knowledge improves as the years go by [59].

References [58], [59] provide a more in depth review of NOA and of alternative processes for transmission expansion planning in other parts of the world. In GB, the Network Planning Review initiative is looking for ways to enhance the described transmission expansion process in terms of providing more 'strategic' decisions and of a more integrated approach of planning for onshore network reinforcements and offshore generation connections [60].

As the NOA is designed around the wider system boundaries and the long term thermal requirement, other processes – the **NOA Pathfinders** [61] – are in place to consider solutions for shorter term timescales, for additional areas of the network or for different type of

37 'Critical' options are a subset of the 'optimal' options. The difference is that 'critical' options require investment in "year 1" so that they are delivered by when their 'required' year is. Options that are not 'critical' effectively require no investment in the next year.

requirements or system needs[38]. These follow the principles of economic justification introduced in NOA and, where possible, they allow for competitive procurement of asset or service based solutions. That means that third party providers (non TO) are also eligible to participate. Pathfinders are run on an as required basis with the expectation to give their place to recurring competitive procurement processes in the near future [52].

With regards to this thesis, the main takeout of this section is that, in a similar way that the network development process compares alternative options on the basis of the consumer benefit they provide to select the preferred ones, this work should compare alternative operational strategies regarding the coordinated preventive and corrective use of QBs on the basis of the reduction in constraint cost they achieve. This is elaborated in Chapter 5.

2.3 The optimal power flow method

The Optimal Power Flow (OPF) [62] method is one of the main computational tools available in steady state power system operations. With it and with the use of defined procedures, SOs can model and solve problems related to power system planning, operation or economics and make more informed decisions. OPF routines are implemented in some of the industry grade power system analysis software tools and Energy Management Systems (EMS) [63].

An optimisation model in its generic form can be described by the following equations[39]:

$$\min_{\mathrm{u}} \mathrm{f}(\mathbf{x}, \mathbf{u}) \tag{2. 1}$$

s.t.

$$\mathbf{g}(\mathbf{x}, \mathbf{u}) = \mathbf{0} \tag{2. 2}$$

$$\mathbf{h}(\mathbf{x}, \mathbf{u}) \leq \mathbf{0} \tag{2. 3}$$

$$\mathbf{x\_min} \leq \mathbf{x} \leq \mathbf{x\_max} \tag{2. 4}$$

$$\mathbf{u\_min} \leq \mathbf{u} \leq \mathbf{u\_max} \tag{2. 5}$$

Model 2-1: Generic OPF model

where

$\mathbf{x}$	is the vector of state (or dependent) variables; typically the voltage magnitude and angle of each node
$\mathbf{u}$	is the vector of control (or independent) variables; active power injections, node target voltages, transformer shift angles or on-load tap changer transformers ratio; they can be continuous or discrete

38 An example is the regional voltage requirement of specific areas addressed by the "High Voltage Pathfinder". That is a requirement to control voltage exceeding the upper limit of equipment instead of the voltage drop usually associated with the bulk power transfers – the main NOA driver.

39 A capital bold letter is used for matrixes, lower case bold for vectors and lower case for scalar values.

f	a scalar objective function; it indicates the user's economic or engineering preferences. It defines the 'optimal' solution, the one with the minimum value, amongst the set of feasible ones
$\mathbf{g}(\mathbf{x}, \mathbf{u})$	the set of equality constraint functions; typically the power flow equations that relate the control and state variables
$\mathbf{h}(\mathbf{x}, \mathbf{u})$	the set of inequality constraint functions; typically model the operational limit of equipment like the maximum power flow through branches
$\mathbf{x\_min}, \mathbf{x\_max}$ $\mathbf{u\_min}, \mathbf{u\_max}$	vectors of bounds on the state and control variables

The selection of state (x) and control (u) variables – together called decision variables – and the exact form the objective function (2. 1) and each of the equations (2. 2) to (2. 3) depend on the application. The OPF model captures a single network operating point and configuration[40] under steady state conditions. In its general form, it is a large scale, non-convex, nonlinear optimisation problem with both continuous and discrete variables – a Mixed-Integer Nonlinear Programing problem.

Applications that use OPF methods (or the Security Constrained OPF variant – section 3.2) include the minimisation of generation cost[41], the transmission congestion management, the minimisation of power losses, maximisation of reactive power reserves and more [64][63]. In terms of how the OPF is used in SO operations, it can be said that OPF methods (or mathematical programming based optimisation more generally) finds more uses in long term planning, with limited use in operational planning and even less so in the context of operation [49].

Challenges and deficiencies

Despite the development of modelling techniques and solution methods over several years some limitations of the OPF method persist or have not been dealt with in a consistent and systematic way. These have been highlighted in many publications, including, [49] [65] [66] and [67] and are also known to power system practitioners. A short overview is provided here with more details about specific challenges or deficiencies covered in the next chapters. The following observations apply for the most part to both the single state (Model 2-1: Generic OPF model) and the security constrained (Model 3-6: Preventive SC-OPF model) OPF versions.

40 Substation running arrangements and equipment switched in.
41 Both the "economic dispatch" and "unit commitment" problems can be modelled as a mathematical programming optimisation problem.

One of the first challenges to be identified is the handling of discrete variables in a practical and computationally efficient way (section 3.1.3). Solution methods for problems with discrete variables (integer or binary), like ‘branch and bound’ or ‘branch and cut’, essentially require the solution of the OPF problem multiple times[42]. Discrete variables have many uses in power system applications. They range from the modelling of the discrete operation of physical controls (transformer taps, shunt capacitor banks and more), to the modelling of binary “strategic” decisions that need to made in day ahead planning (such as arming a special protection scheme or bringing a generator online). Practical applications, that use approximations, heuristics or decomposition techniques, could be effective in dealing with specific types of discrete variable but they are not necessarily extendable to others.

A second challenge is limiting the controls used in the OPF solution (section 3.4). As the optimiser’s aim is to minimise the objective function value it will try to make use of all the controls available in the problem formulation. This could result in solutions where too many controls are used, where controls are only used to a limited extent or where controls that have less engineering relevance to the objective are used together with ones that have more. Selecting the ‘most important’ subset of controls is not straightforward. Each control participates in a non-separable way in improving the objective function and ensuring the constraints’ feasibility. The output of the OPF, as is, does not rank the control actions and the importance of each control action is not related to its magnitude (although it is acknowledged that this can be mitigated using info from the dual problem together with information about the electrical effectiveness of controls).

This brings us to another related deficiency, the handling of automated controls and the modelling of the SO’s engineers “operational preferences”. First, a comparison is made with the “conventional” power flow (PF) method [68] that is widely used in SOs’ processes.

The OPF and PF methods share common ground, mainly in the form of the modelling of the system (power flow equations) and the underlying computation process (they both solve a system of non-linear equations iteratively). Unlike PF, the OPF method can directly incorporate constraints – including security ones. Indeed, the main PF routine (the “internal” Newton-Raphson routine that solves the power flow equations) does not, by itself, enforce any operational limits and the PF application relies on “external” control adjustment cycles to enforce the generators reactive power limits for instance or to find the correct tap setting for

42 Branch and bound, for instance, partitions the solution space into smaller convex sets/regions and as part of the solution process it must find the a “lower” and an “upper” objective value bound for some of the regions. Finding bounds requires solving a “relaxed” optimisation problem or one where certain discrete variables are fixed [201].

on-load tap changer transformers or capacitor banks. The application iterates between the internal routine and the control adjustment cycles until all operational limits are satisfied.

However, in that way a well-designed PF application can replicate the hierarchical structure of the actual power system, where different levels of control exist, some supervisory and coordinated and others of local and autonomous. Interactions between devices of the same type due to their position (i.e. parallel transformers) or due to their different activation times (i.e. transformers at different voltage levels) can be captured or simulated using appropriate dead bands and time constants. Further, the adjustment cycles can cope with the discrete nature of controls and can provide the likely sequence of actions that will take place in the power system. PF can also easily incorporate user priorities regarding the activation of controls or the number of actions allowed and can model pre-defined automated actions like the activation of special protection schemes or the automated operation of FACT devices.

The generic OPF formulation assumes supervisory coordinated control throughout and implies that one single entity has visibility over the whole system and the ability to enforce its decisions over all components. This may be true for some applications but it may not be true overall. Also, interactions between controls such as the ones previously described, user priorities or automated actions are usually not modelled as they cannot be expressed into (convex) algebraic equations in a straightforward way.

Following on from the discussion, it should be noted that the OPF, in its general form, is a single step optimisation approach. It provides a set of control actions but not the sequence that they should be applied in. So it is not given that the system will not experience any operational limits violations in the transition from the initial operating state to the one that corresponds to the OPF solution. The same can be said for the transition from one operating state (i.e. trading period) to the next when both are the output of an OPF solution.

To overcome that, some approaches use multi-period or dynamic OPFs, where the optimisation problem is solved over a number of dispatch periods that are linked with inter-temporal constraints [69]. This ensures that the optimiser is using controls with limited inter-temporal capacity (hydro or battery storage) efficiently. Multi-period OPF together with receding horizon model predictive control (MPC) has been proposed as a way to provide a secure transition path for corrective control actions [70] or to simulate the behaviour of voltage controls [71]. Uncertainty (in the intraday or day ahead timescales) can be handled as the optimiser is adjusting for the actual system state in every optimisation step [72].

It should be noted that MPC inspired schemes tend to defer the execution of controls for as late in the optimisation horizon as possible if no heuristics or custom objective function weightings are applied. This could make them less suitable for corrective control applications where SO engineers try to limit as much of the excess flow as quickly as possible and they would want to use the most effective and/or fastest to operate controls first.

In reference [73] the QB tap settings transition problem between an initial and the 'optimal' set of tap settings is modelled as a graph where each point represents a different combination of tap settings. Each point in a graph results in a different TTC for a transmission boundary (in this case the border boundary between the Netherlands and Belgium). A greedy algorithm is used to find the "shortest path", the one that minimises the TTC variation from the final, optimal value. The greedy algorithm is used instead of a shortest path algorithm due to the requirement to find a good enough transitions path instead of the shortest one and its better computational performance. A penalty term is introduced in the objective to help limit excessive switching.

Further, as the OPF method is using the steady state power flow equations, it cannot be guaranteed that the solutions it provides are secure from a dynamic stability perspective. It has been noted that directly coupling a SC-OPF method with time domain simulation is not likely to produce a process suitable for practical applications as they are both computationally intensive calculations [67]. Reference [74] uses quasi steady state simulation as it offers a trade-off between accuracy and speed. A commonly used approach is to incorporate stability limits as linear constraints that limit the MW flow over specific network branches or boundaries – where the "right hand side" value is determined by offline stability studies.

Another challenge is the inclusion of Direct Current (DC) networks in the OPF calculation especially when the voltages and currents of the internal HVDC components must be known such as when SOs are scheduling the active and reactive power of a link for instance. Reference [75] addresses that by developing a comprehensive AC/DC OPF tool that is a parameterised so that it can be adapted to the various HVDC technologies and designs. Second order cone relaxation and linear approximations are successively applied to the "reference" AC and DC grid component equations to remove non convexity and the non-linearity of the reference equations. The relaxation and approximations can be selectively applied to the various components (AC branch, Converter station and DC branch) derive several possible OPF problem formulation.

Reference [49] highlights "models and data" as an issue for the adoption of OPF methods in SOs' operations in short term planning or operation. Data come from multiple sources and are used in various proprietary systems – Supervisory Control and Data Acquisition (SCADA), EMS, state estimator. Each holds its own data, often in different formats or update frequencies and there is no single repository with all the data that the OPF model would need. State estimator data can contain errors or be approximations. For the OPF to be applied in real-time or 'closed loop' applications (where the output is fed back directly to the system) data reliability and consistency is of high importance.

Navigating through the challenges

As discussed in section 2.2.1, the power system operations can be viewed as a sequence of interacting stages that take place over different timeframes. The objectives of each stage are different as are the data available, the outputs required, the uncertainties that apply and the ways that they can be handled. Each stage consists of multiple activities that could be for instance covering different power system phenomena or aspects of the operation[43]. Although the need to incorporate more mathematical programming based optimisation into the SOs' decision making processes is recognised [76], it can be said that, because of the necessities and practicalities of the various activities of each stage as well as the differences in the nature or granularity of the output each requires, one way forward could be to use more targeted OPF/optimisation approaches.

Approaches that do not try to tackle a multitude of the challenges described previously into a single, integrated optimisation problem or process or provide a "comprehensive" answer that covers multiple activities at once[44], but instead focus on certain activities and use OPF/optimisation methods to provide a contained, specific and usable output. In this case, OPF methods could be used to inform the SO decision making or actions, instead of to determine them, and they could be part of a broader framework/process that uses optimisation in its core. They could enhance or complement the processes that the SOs already have in place for the same activities instead of reshaping them. That way, even if they do not provide the answer to all questions and challenges the SOs are facing, they should be able at the very least to take advantage of computational strengths of OPF methods and provide improvements where they are needed.

43 An example of the former is the modelling of steady state or dynamic phenomena, previously mentioned, that require different type of power system studies and of the latter is the management of constraints and the procurement of ancillary services during operational planning. There are interactions between these activities and phenomena and the ways they are studied/handled in practice but the focus of this section is more on how OPF methods can be used with respect to them.

44 One notable exception is when the activities are very closely coupled such as day ahead and intraday planning –as in [105]

Further developments

One field of research that has received attention in recent years is that of optimisation under uncertainty. Due to the variable renewable energy output, market operations, fuel prices, weather conditions, the impact of climate change and more, ‘uncertain parameters’ must be considered in the decision making frameworks together with the optimisation variables of a deterministic OPF problem [77].

Estimating the range of possible values of the uncertain parameters (for instance by using a known probability distribution or inferring it through a dataset of historic values), how they are used in an analytical framework (for instance through sampling of the distribution to create snapshots, directly representing the distribution in the model or using a range of user defined extreme values) and the way that risk operators are defined (for instance the risk of excessive cost or the risk of constraint violation) are all factors that can give rise to alternative mathematical optimisation problem formulations and resulting solution algorithms. An extensive review of these is provided in [77]. The main approaches for optimisation under uncertainty are referred to as ‘robust’ optimisation ([78], [79]), ‘stochastic optimisation’ [80] and ‘chance-constrained optimisation’ as in [81], [82], [83] and [84] for instance.

Another area of active research is exploring ways to solve near real-time SCOPF problems fast and accurately for use in practical applications. In the later years, relaxations such as second-order cone programming [85] and semidefinite programming [86] [87] have been proposed as possible alternatives to the inability of other methods to find a global optimum solution to the non-convex AC SCOPF problem [88]. Further approaches try to establish better coupling conditions between the base case and the contingency case sub-problems in a way that considers the frequency response of the generators to contingencies [89] [90].

The authors of [91] combine the non-convex relaxation of the complementarity constraints solution method with a contingency ranking and pre-screening technique that is applied within a decomposed framework that considers automatic response of controls (frequency response and voltage regulation) using sparse resource approximation terms. The above – and the use of parallel computing – allowed the solution of very large problems (without the need for network compression or approximation of post-contingency states) at times that are compatible with intraday short-term planning requirements.

3 Optimal power flow models for QB tap settings coordination

In this chapter we will develop a number of OPF models, each covering a different aspect of how the OPF method can be used to re-dispatch active power controls. Some of the models are combined in the next chapter to form a framework for the coordination of QB tap settings. The rationale and the choices made when developing each model are explained.

3.1 A basic optimal power flow model

This section builds up, step by step, a basic OPF model for selecting the optimal settings of active power controls. The starting point for the discussion that follows is the generic OPF model presented in Chapter 2 (Model 2-1).

3.1.1 Basic features of the model

In the following we will focus on the active power sub-problem of the power system operation. There are a number of reasons for that:

- QBs are active power controls.
- Constraint cost in the long term future is expected to be incurred because of deficit of transmission transfer capacity i.e. because of thermal constraints [9].
- OPF models cannot effectively model the decentralised hierarchical way of operation of some voltage/reactive power controls[45] [65], [67].
- Power system engineers generally operate the network considering the active power and the reactive power/voltage sub problems as decoupled in short-term planning. In practice, they expect active power control instructions only for handling thermal constraints. This is justified by the weak coupling between bus active power injections and bus voltage magnitude (or between reactive power injections and bus voltage angles) in the power flow solution Jacobian matrix[46] of the meshed high voltage (transmission) networks.
- The decoupling then makes engineering sense and avoids creating badly posed[47] optimisation problems where voltage controls are used to also regulate power flows.

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45 Power flow analysis software handle voltage/reactive power controls by cycling through the “internal” Newton-Raphson routine that solves the AC power flow equations and one or more “external” control adjustment loops. Solving an OPF model’s equality constraints is akin to the internal routine.

46 At least for a system that is not close to its stability limit.

47 A badly posed problem is defined in the following as one where there is the opportunity of a solution where voltage/reactive power controls are used to also regulate active power flows or the opposite.

- From a long-term system planning perspective, it is the scheduling of the large scale options such as transmission route upgrades or new transmission circuits that poses the greatest challenges and offers the greatest opportunity for constraint cost reduction as they enable higher volume of flows out or through an area. The transmission expansion problem with regards to these options can be adequately tackled considering the active power control sub problem only. Reactive compensation options (such as mechanically switched capacitors and reactors) that are used to solve voltage issues are usually more flexible in their scheduling and have shorter lead times.

As is explained in literature, the change in bus active power injections and bus voltage angles (and consequently the change in active power flow of the branches) can be approximated by a set of linear relations. This leads to an OPF model where the form of the equations (2. 2) and (2. 3) (of Model 2-1) is linear and only independent, control variables (u) are used.

There are generally three ways we can extract that linear relation:

- From the linearisation of the AC power flow equations around a solution point[48]. Similar to other types of AC sensitivities, their accuracy is better within small disturbances around the solution point [92].
- Using the Fast Decoupled load flow approximation[93].
- Using the DC power flow approximation.

In the following we will use the well-established DC power flow approximation. Reference [94] suggests that the approximation offers better accuracy when used as a “hot start” model – based on an AC power flow solution if available and/or at incremental applications. It is also noted that the overall accuracy and fit for purpose is dependent on the actual power system/network model, operating conditions and application. Reference [95] examines the DC power flow from the perspective of power flow control devices applications. It provides indexes to quantify the validity of the assumptions[49] of the DC method for a given network and operating conditions.

Ultimately, it can be said that system operators do not necessarily need algorithmically optimal solutions from an algorithmic perspective but near optimal solutions from an operational perspective [96]. In practice, this means that a solution from an approximate DC power flow model or a DC based OPF could be good enough if it answers the question it was used for.

48 Solved using the Newton-Raphson method.
49 Indexes regarding the voltage profile deviation, the X/R ratio of the branches and the voltage angles of the nodes.

Further, there are two forms that the model can take:

- Sparse format of equality and inequality constraints
- Non-sparse format of equality and inequality constraints

Using the sparse format, the DC power flow equations become part of equations (2. 2) and are solved at the same time as the OPF model itself. It effectively becomes a power flow with an optimality measure and constraints. An example of a OPF model using the sparse formulation is provided in Appendix C: Sparse OPF model.

In the non-sparse format, the user has to supply 'sensitivities' (as for instance the Power Transfer Distribution Factors – section 3.1.2) that relate the change in the control variables to the value of the constraints. They are used in equation (2. 3) directly and equations (2. 2) do not need to be included. The non-sparse format lends itself naturally to an incremental, re-dispatch problem, a problem where the sought after solution is a deviation from an already established operating point as in (3. 1). We will use the non-sparse format in the rest of the chapter.

$$\mathbf{h}(\mathbf{x}^0, \mathbf{u}^0) + \mathbf{h}(\mathbf{x}, \mathbf{u}) \leq \mathbf{0} \tag{3. 1}$$

3.1.2 Control variables and branch flow constraints

Table 3-1 lists the assets that will be used as active power control variables

Table 3-1: Operational measures for active power control

Method	Procurement
Generator active power	Balancing Mechanism
Interconnector active power	Balancing Mechanism or Constraint Management Agreement
Embedded HVDC link set point	ESO instruction to TO
QB tap setting	ESO instruction to TO

In GB, there is no cost involved in the ESO instruction to TO for use of the QBs or the embedded HVDC link. The ESO has the ability to issue these instructions as often as required.

The OPF model inequality constraints should reflect that no network branch element (overhead line, cable section, transformer) or other related component (such as circuit breakers) should ever exceed its rating (current limit). As explained in section 2.2.5, the overall rating of a branch is usually determined by the ability of the branch elements to tolerate or dissipate heat i.e. it is a "thermal" rating [53].

Power Transfer Distribution Factors (PTDFs) are sensitivity factors that relate the power exchange between two buses (in this context, a positive power injection in bus *i* with a negative power injection of equal magnitude in the slack bus) with the change of power flow through a branch. Due to the linearity of the DC model the superposition principle applies: the overall change in flow in branch *km* due to the injection of X MW in bus *i* and Y MW in bus *j* can be calculated as the sum of the individual changes. Generator, interconnector and HVDC link control variables in Table 3-1 can be modelled as bus power injections.

PTDFs can be used to calculate the sensitivity of all controls in Table 3-1. Generators and Interconnectors are of course modelled as active power injections. Embedded HVDC links are modelled as two active power injections of equal magnitude but opposite sign, one on each of the link's landing locations [97]. PTDFs can also be used to calculate sensitivity factors that relate a QB tap change to the change of branch power flow. We will call them QB Distribution Factors (QBDFs). Details about the modelling of the above controls how to derive both PTDF and QBDF under DC power flow assumptions can be found in the Appendix B: Power system sensitivities.

Consequently, we can use PTDFs and QBDFs to form the inequality constraints of the OPF model as in (3. 2):

$$-\mathbf{l}^{\max} \leq \mathbf{l}^{\text{init}} + \mathbf{A}_{\text{PTDF}}\,\mathbf{x} + \mathbf{A}_{\text{QBDF}}\,\mathbf{x} \leq \mathbf{l}^{\max} \tag{3. 2}$$

where	$\mathbf{l}^{\max}$	a $\mathrm{n_l}$ x 1 vector of branch limits, where $\mathrm{n_l}$ is the number of branches
	$\mathbf{l}^{\text{init}}$	a $\mathrm{n_l}$ x 1 vector of initial branch flows
	$\mathbf{x}$	a $\mathrm{n_c}$ x 1 vector of control variables, where $\mathrm{n_c}$ is the number of controls
	$\mathbf{A}_{\text{PTDF}}$	an $\mathrm{n_l}$ x $\mathrm{n_c}$ matrix of PTDFs where a_{ij} is the PTDF that relates the change of control j to the change in flow of branch i
	$\mathbf{A}_{\text{QBDF}}$	a_{ij} is the QBDF that relates the change of control j to the change in flow of branch i

3.1.3 Objective function

The objective function is a scalar function of control and state variables. It a measure of optimality and allows the solution algorithm to find the optimal solution among the set of feasible ones. Having established that we will use linear constraints there are two further decisions that we need to make:

- the type of the decision variables (all continuous or some integer) and,
- the form of the objective function (linear or quadratic function)

The above will determine the overall type of the OPF problems as Linear Programming (LP), Quadratic Programming (QP) or, if integer variables are used, Mixed Integer Linear Programming (MILP) or Mixed Integer Quadratic Programming (MIQP). For linear programs and convex quadratic programs established solvers exist.

Continuous or integer control variables

Generator and link active power set points are continuous variables as their MW output can take any value within their operational limits. The QB tap settings are integer ones: taps can take only discrete values and so does the incurred phase-shift.

QB taps, similar to taps of transformers that regulate voltage, are variables with small discrete steps. If modelled as continuous variables, selecting a tap setting between the two possible integer values (rounding up or down) usually has limited effect on the overall outcome: reducing an overload or the objective function value.

This is not true for variables with large discrete steps such as network switching (of branches or of shunt reactive control assets) or in the case of binary variables that model decisions - such as starting up a generation unit, arming an intertrip or deciding on a transmission expansion stage. In that case integer or binary variables that help model these outcomes must be introduced.

Integer variables are also used when we need to introduce an engineering restrictions or operational rules in the model such as limiting the number of controls used. Integer variables help model the OPF constraint that sets the limit on the number of controls but the variables that model the volume of each control can still be continuous. A model of that type is developed in section 3.4.2.

A simple approach for handling integer variables with small discrete steps is to solve a "relaxed" OPF problem where all variables are treated as continuous first and then round-off the discrete variables to the nearest integer value. Following that, the OPF problem could be solved again (starting from the previous solution) with the discrete variables frozen to their integer variables. If there is any further constraint violation because of the rounding, the continuous variables will be adjusted to alleviate it.

Other approaches can be found in the following references. In [98], an approach that iterates between a "relaxed" OPF solution and an discretisation step that uses an 'adaptive' or 'probabilistic' threshold technique to fix a subset of the shunt controls to an discrete value is proposed. Reference [99] employs first order sensitivity information to decide on the better integer value at the "relaxed" OPF solution. The authors of [100] and [101] use penalty terms in the OPF objective and a combination of heuristic rules to drive the integer variables to discrete values. References [98] and [99] provide a more extensive review of further approaches on the subject.

At present, we will use continuous control variables to model the QB tap settings.

Linear or quadratic objective function

In a linear program, the objective function is a scalar linear function of the decision variables as in equation (3. 3)

$$\min \mathrm{f}(\mathbf{x}) = \mathbf{c}^{\mathrm{T}}\mathbf{x} \tag{3. 3}$$

where	$\mathbf{c}$	is the vector of decision variable coefficients (same dimension as x)

The generic form of a quadratic program objective function is:

$$\mathrm{q}(\mathbf{x}) = \frac{1}{2}\,\mathbf{x}^{\mathrm{T}}\mathbf{G}\,\mathbf{x} + \mathbf{c}^{\mathrm{T}}\mathbf{x} \tag{3. 4}$$

where	$\mathbf{G}$	is a symmetric nc × nc matrix describing the coefficients of the second degree and cross-product term of the polynomial
	$\mathbf{c}$	a vector describing the coefficients of the linear terms

If **G** is positive semidefinite (in a minimisation problem) the quadratic program is convex. This is the case when the polynomial does not have any cross-product terms and the coefficients of all second order terms are ≥ 0.

A quadratic objective function would tend to distribute the control actions in a more balanced way between the available controls. This can be seen as an advantage or not depending on the application: for an incremental, re-dispatch application one of the engineering objectives is to disturb the operating point established by the market as little as possible. One metric of that is to have fewer market participants needing to re-dispatch. Further, if the re-dispatch takes place after a fault (corrective actions) the number of Bids and Offers issued should be no more than necessary.

A linear objective also represents more naturally the relationship between the volume of energy procured for re-dispatch actions and the cost incurred. This relationship is (piecewise) linear as a single price per MWh is submitted in each Bid or Offer band [12]. In the following we will use a linear objective function.

Objective function coefficients

We need to consider the following about the objective function:

1. The OPF model should not re-dispatch a control when there is no constraint violation. In a minimisation problem, the lowest possible objective value should be zero – i.e. no control movement.
2. The model should accept different objective coefficients for the same control variable depending on the direction of re-dispatch (a generator would submit different prices to be Bid off or Offered on)
3. The objective should include both controls that are monetarised (generators and interconnectors) and controls with no direct monetary cost (QB taps and embedded HVDC link set point)[50] in a way that the solution make engineering and economic sense.

Having decision variables that are not bounded by zero (i.e. controls that can be re-dispatched to negative values) and still achieve point 1 above is akin to the following model/objective

	$\min \sum_{j=1}^{n} c_j \lvert u \rvert$	where $c_j \geq 0$ for $j = 1$ to n	(3. 5)
s.t.	$\sum_{j=1}^{m} a_{ij} u_{ij}$	for $i = 1$ to m	(3. 6)

Model 3-1: First norm objective

where $\lvert\,\rvert$ is the absolute value operator. According to [102] each variable u_j can be replaced by its positive and negative parts: $u_j = u_j^+ - u_j^-$ where $u_j^+ \geq 0$ and $u_j^- \geq 0$. Of course each control must have at most only one of its two variables at non-zero values at the optimal solution. To enforce that explicitly requires the non-linear constraint $u_j^+ * u_j^- \geq 0$. Model 3-1 can then be rewritten:

50 This is strictly true if network losses are neglected. A change in the power flows will impact the cost of balancing the network through the resulting change in the network losses. The point we want to make here however is that there is no "direct" cost imposed by the market as these assets are owned by the transmission owner.

	$\min \sum_{j=1}^{n} c_j\ (u_j^+ + u_j^-)$	where $c_j \geq 0$ for $j = 1, \ldots, n$	(3. 7)
s.t.	$\sum_{j=1}^{m} a_{ij}(u_j^+ - u_j^-) = b_i$	for $i = 1$ to m	(3. 8)
	$u_j^+ \geq 0$ and $u_j^- \geq 0$		(3. 9)
	$u_j^+ * u_j^- \geq 0$		(3. 10)

Model 3-2: Positive and negative counterparts objective

Model 3-2 is no longer a linear model as the last constraint is not linear. However, in the same reference [102] the proof[51] is provided that, if a problem is defined by equations (3. 7) to (3. 9) only – i.e. dropping the non-linear constraint (3. 10) – and all $c_j \geq 0$ then there exist a finite optimal solution to equations (3. 7) to (3. 9) such that either of u_j^+ or u_j^- is zero provided there is feasible solution. From a power system perspective this can be understood because using both parts of a variable would undo the control action (the parts have the same but opposite electrical sensitivity towards the overload/constraint) and increase the objective value at the same time.

By modelling each control with two variables, u_j^+ and u_j^- as in (3. 7) to (3. 9), also allows the use of different coefficients for each part/variable i.e. c_j^+ and c_j^-. That way we can include different Bid and Offer price for each generators. The proof in [102] can be straightforwardly extended to cover this provided both c_j^+ and c_j^- remain ≥ 0.

Thermal generators tend to submit positive Bids in the Balancing Mechanism. A positive Bid is a source of revenue for the system operator and it should be used in place of a negative Bid (e.g. from a renewable generator) when available to achieve the most economical solution.

The objective function coefficients of the OPF model should be tuned to reflect the order of preference and the relative difference between the submitted Bids while still being positive. The following two step process is used:

In the following:

$\mathbf{offer}_{\mathrm{bmu}}$	A nc x 1 vector of Offers submitted in the Balancing Mechanism(£/MWh) – all positive.
$\mathbf{bid}_{\mathrm{bmu}}$	A nc x 1 vector of Bids submitted in the Balancing Mechanism (£/MWh) – either positive or negative.
$\mathbf{c}_{\mathrm{bmu}}^{+}$	A vector of objective value coefficients for offering generators on

51 Lemma 6.1 on Chapter 6 of [102]

$\mathbf{c}_{\mathrm{bmu}}^{-}$	A vector of objective value coefficients for bidding generators off
c_{offset}	A user define constant

Step 1 $$c_{\mathrm{bmu}}^{-} = -1 * \mathbf{bid}_{\mathrm{bmu}} + \max(\mathbf{bid}_{\mathrm{bmu}}) + c_{\mathrm{offset}}$$
Step 2 $$\mathbf{c}_{\mathrm{bmu}}^{+} = \mathbf{offer}_{\mathrm{bmu}} + c_{\mathrm{offset}}$$

Step 1 first multiplies all Bids by -1 and then offsets each by as much as the value of the maximum Bid submitted plus a predefined constant (c_{offset}). That way all Bids end up having positive values and the relative difference between them is preserved. Both step 1 and step 2 offsets the BM submitted values by c_{offset} units. This creates a headroom in the low end of the range of objective coefficients – between $(0, c_{\mathrm{offset}}]$ – that can be used for the coefficients of non-monetarised controls or other variables that are used to enforce operational preferences or engineering constraints. The exact value of c_{offset} is not important but it is recommended that it is an order of magnitude greater than the coefficient used for the most "expensive" non-monetarised control. It is worth noting that all control variables should have a non-zero cost in a well-defined optimisation problem.

3.1.4 Bounds on control variables and other constraints

The bounds determine the max and min value each control is allowed to take in the OPF problem. Splitting each control to its positive and negative counterpart, u_j^{+} and u_j^{-}, mean that the positive and negative counterpart upper bound will be used to set the limit of the control re-dispatch towards positive or negative values respectively, as in Figure 3-1. Both counterparts should have a zero lower bound.

The bounds of the individual controls are set either by the operational limits of the asset or by other restrictions such as the engineering preferences or commercial arrangements. Table 3-2 summarises what the latter two restrictions are for each control type. The restriction that comes first will determine the bound value – i.e. the engineering limit in the example of Figure 3-1.

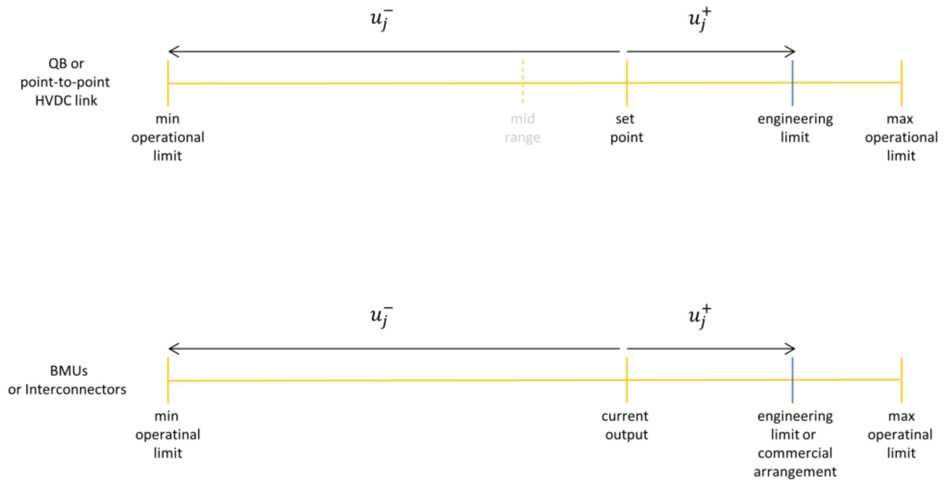

Figure 3-1:Example on setting the bounds for control variables

Table 3-2: Engineering and commercial restrictions that determine the bounds of controls

Control	**Engineering restriction**	**Commercial restriction**
Generator active power	Ramp up rate Ramp down rate Resource availability	Power made available in the BM
Interconnector active power	Converter and cable technology SO to SO agreement	Commercial arrangements
Embedded HVDC link set point	Converter and cable technology	None (in the GB system)
QB tap setting	Tap changer speed Engineering preferences or business procedures	None (in the GB system)

The time available for actions is underpinning all restrictions. It becomes more relevant if the OPF model is used to calculate corrective actions that would be applied after a forced network equipment outage (fault outage). The time that the network elements can withstand loading of equipment above its 'continuous' rating after such an event is limited (section 2.2.5). The response rate of the control will determine the volume of corrective action that can be achieved and will set the engineering restriction. This is relevant for thermal generation and QBs but not so for sources of energy behind power electronic converters that can respond very fast.

Interconnectors link electricity markets and are also owned by third party – non TO - entities. The way interconnectors participate in balancing markets or constraint management services on either end has to be agreed between the TSOs involved and the interconnector owners. Often the agreement allows the interconnectors to be ramped down to an output value close to zero (float position) but does not allow them to switch the direction of flow.

This can be understood both from a commercial and security perspective. Reversing the direction of flow to help manage constraints on SO area A could have adverse effects for the security of the SO area B. SO area B will have to be secured against the event of the interconnector reversing direction of flow which could adversely increase the cost of operating area B.

HVDC links (either interconnector or embedded links) can also be limited by the converter and cable technology. Reference [50][52] explains that – for links that use current source converters and mass impregnated cables – a wait has to be introduced after the DC polarity is reversed before the operators can restart the power flow in the opposite direction.

In the context of GB system (that is an island linked with HVDC links to mainland Europe operated by a single SO) there are no commercial or security implications from the use of embedded HVDC links or QBs to other markets/SO areas. This is not true for synchronously interconnected systems as both controls can significantly influence power flows on adjacent SO areas.

Appendix E: Study setup explains in detail how the bounds were set for each type of control in the test model in order to obtain the results presented in Chapter 5.

3.1.5 The complete OPF model

The single state OPF model described in sections 3.1.1 to 3.1.4 can be written as:

$$\min f(x) = \mathbf{c}_{bmu}^{+}\mathbf{x}_{bmu}^{+} + \mathbf{c}_{bmu}^{-}\mathbf{x}_{bmu}^{-} + \mathbf{c}_{qb}^{+}\,\mathbf{x}_{qb}^{+} + \mathbf{c}_{qb}^{-}\,\mathbf{x}_{qb}^{-} + \mathbf{c}_{ic}^{+}\,\mathbf{x}_{ic}^{+} + \mathbf{c}_{ic}^{-}\,\mathbf{x}_{ic}^{-} + \mathbf{c}_{dc}^{+}\,\mathbf{x}_{dc}^{+} + \mathbf{c}_{dc}^{-}\,\mathbf{x}_{dc}^{-} \tag{3.11}$$

s.t

$$-\mathbf{l}_{max} \le \mathbf{l}_{init} + \mathbf{A}_{G}\,\mathbf{x}_{bmu}^{+} - \mathbf{A}_{G}\,\mathbf{x}_{bmu}^{-} + \mathbf{A}_{Q}\,\mathbf{x}_{qb}^{+} - \mathbf{A}_{Q}\,\mathbf{x}_{qb}^{-} + \mathbf{A}_{I}\,\mathbf{x}_{ic}^{+} - \mathbf{A}_{I}\,\mathrm{x}_{ic}^{-} + \mathbf{A}_{D}\,\mathbf{x}_{dc}^{+} - \mathbf{A}_{D}\,\mathbf{x}_{dc}^{-} \le \mathbf{l}_{max} \tag{3.12}$$

52 Appendix E of Reference [50] – "Technology"

$$\sum_g x_{\mathrm{bmu}_g}^{+} - \sum_g x_{\mathrm{bmu}_g}^{-} + \sum_t x_{\mathrm{ic}_t}^{+} - \sum_t x_{\mathrm{ic}_t}^{-} = 0 \tag{3. 13}$$

$$\mathrm{x}_{\mathrm{dc}_{\mathrm{north}_j}}^{+} - \mathrm{x}_{\mathrm{dc}_{\mathrm{north}_j}}^{-} + \mathrm{x}_{\mathrm{dc}_{\mathrm{south}_j}}^{+} - \mathrm{x}_{\mathrm{dc}_{\mathrm{south}_j}}^{-} = 0 \ \forall j \in \{1 \dots \mathrm{n}_{\mathrm{dc}}\} \tag{3. 14}$$

$$0 \le \mathbf{x}_{\mathrm{bmu}}^{+} \le \mathbf{ub}_{\mathrm{bmu}}^{+}, 0 \le \mathbf{x}_{\mathrm{bmu}}^{-} \le \mathbf{ub}_{\mathrm{bmu}}^{-} \tag{3. 15}$$

$$0 \le \mathbf{x}_{\mathrm{qb}}^{+} \le \mathbf{ub}_{\mathrm{qb}}^{+}, 0 \le \mathbf{x}_{\mathrm{qb}}^{-} \le \mathbf{ub}_{\mathrm{qb}}^{-},$$

$$0 \le \mathbf{x}_{\mathrm{ic}}^{+} \le \mathbf{ub}_{\mathrm{ic}}^{+}, 0 \le \mathbf{x}_{\mathrm{ic}}^{-} \le \mathbf{ub}_{\mathrm{ic}}^{-},$$

$$0 \le \mathbf{x}_{\mathrm{dc}}^{+} \le \mathbf{ub}_{\mathrm{dc}}^{+}, 0 \le \mathbf{x}_{\mathrm{dc}}^{-} \le \mathbf{ub}_{\mathrm{dc}}^{-}$$

Model 3-3: Single state OPF model

where

$\mathbf{x}_{\mathrm{bmu}}^{+}, \mathbf{x}_{\mathrm{bmu}}^{-}$	$\mathrm{n_g}$ x 1 vectors of decision variables for generation re-dispatch, positive and negative counterparts – where $\mathrm{n_g}$ is the number of generators that can be re-dispatched; unit is p.u. MW
$\mathbf{x}_{\mathrm{qb}}^{+}, \mathbf{x}_{\mathrm{qb}}^{-}$	$\mathrm{n_{qb}}$ x 1 vectors of decision variables for QBs tap setting reschedule, positive and negative counterparts – where $\mathrm{n_{qb}}$ is the number of QBs; unit is tap
$\mathbf{x}_{\mathrm{ic}}^{+}, \mathbf{x}_{\mathrm{ic}}^{-}$	$\mathrm{n_{ic}}$x 1 vectors of decision variables for interconnector output re-dispatch, positive and negative counterparts - where $\mathrm{n_{ic}}$ is the number of interconnectors; unit is p.u. MW
$\mathbf{x}_{\mathrm{dc}}^{+}, \mathbf{x}_{\mathrm{dc}}^{-}$	(2 * $\mathrm{n_{dc}}$) x 1 vectors of decision variables for embedded HVDC link set point reschedule, positive and negative counterparts – where $\mathrm{n_{dc}}$ is the number of links[53]; unit is p.u. MW
$\mathbf{c}_{\mathrm{bmu}}^{+}, \mathbf{c}_{\mathrm{bmu}}^{-}$	1 x $\mathrm{n_g}$ vectors of objective function coefficients for the generation re-dispatch decision variables
$\mathbf{c}_{\mathrm{qb}}^{+}, \mathbf{c}_{\mathrm{qb}}^{-}$	1 x $\mathrm{n_{qb}}$ vectors of objective function coefficients for the QBs tap setting reschedule decision variables
$\mathbf{c}_{\mathrm{ic}}^{+}, \mathbf{c}_{\mathrm{ic}}^{-}$	1 x $\mathrm{n_{ic}}$ vectors of objective function coefficients for the interconnector re-dispatch decision variables
$\mathbf{c}_{\mathrm{dc}}^{+}, \mathbf{c}_{\mathrm{dc}}^{-}$	1 x $(2 * \mathrm{n_{dc}})$ vectors of objective function coefficients for the embedded HVDC link reschedule decision variables
$\mathbf{l}^{\max}, \mathbf{l}^{\mathrm{init}}$	$\mathrm{n_l}$ x 1 vectors with the thermal ratings of braches and the initial branch flow ('From' side) respectively; unit is p.u. MW
$\mathbf{A}_{\mathrm{G}}$	$\mathrm{n_l}$ x $\mathrm{n_c}$ matrix of PTDFs for the generator decision variables
$\mathbf{A}_{\mathrm{Q}}$	$\mathrm{n_l}$ x $\mathrm{n_q}$ matrix of QBDFs for the QB decision variables
$\mathbf{A}_{\mathrm{I}}$	$\mathrm{n_l}$ x $\mathrm{n_{ic}}$ matrix of PTDFs for the interconnector decision variables
$\mathbf{A}_{\mathrm{D}}$	$\mathrm{n_l}$ x $(2 * \mathrm{n_{dc}})$ matrix of PTDFs for the decision variables modelling the embedded HVDC links
$\mathbf{ub}_{\mathrm{bmu}}^{+}, \mathbf{ub}_{\mathrm{bmu}}^{-}$	$\mathrm{n_g}$ x 1 vectors of upper bounds for the generator decision variables; unit is p.u. MW
$\mathbf{ub}_{\mathrm{qb}}^{+}, \mathbf{ub}_{\mathrm{qb}}^{-}$	$\mathrm{n_{qb}}$ x 1 vectors of upper bounds for the QB decision variables; unit is tap
$\mathbf{ub}_{\mathrm{ic}}^{+}, \mathbf{ub}_{\mathrm{ic}}^{-}$	$\mathrm{n_{ic}}$ x 1 vectors of upper bounds for the interconnector decision variables; unit is p.u. MW
$\mathbf{ub}_{\mathrm{dc}}^{+}, \mathbf{ub}_{\mathrm{dc}}^{-}$	$(2 * \mathrm{n_{dc}})$ x 1 vectors of upper bounds for the embedded HVDC link decision variables; unit is p.u. MW

53 Remember two variables are required to model each link.

In the objective function (3. 11), the coefficients for the BMU and interconnector controls reflect monetary cost. The coefficients for QBs and the HVDC link (where there is no monetary cost) should be seen as penalty terms. They are used to ensure that the OPF will not instruct more QB tap or HVDC set point changes than required.

Constraint (3. 13) is there to ensure the balance of generation and demand. Assuming the balance was already established before the OPF calculation takes place, the constraint ensures that the amount of power taken off the system, by accepting generator or interconnector Bids, is replaced by accepting equal volume of Offers. The set of constraints described by (3. 14) ensures that the decision variables for the two generators modelling each HVDC link are dispatched towards equal but opposite values. In Model 3-3 the PTDF and QBDF are calculated for the 'From' side of each branch.

The starting point for Model 3-3 can be any network situation where there is a branch flow constraint violation or a violation of the generation and demand balance constraint. The first can be the result of a contingency of another branch and the second that of the market providing a generation and demand dispatch where balance has not been established. The model can be used in either of these situations to provide the minimum cost solution where the balance is re-established and the flow of all the branches falls back within the specified limits. In Chapter 5, a model based on Model 3-3 is used to find the minimum cost corrective actions to alleviate branch flow constraint violations after branch contingencies[54].

3.2 The security constrained OPF method

In this section, we expand the OPF model of section 3.1 – that considers a single network state only – to become a Security Constrained OPF model (SC-OPF), one that considers network configurations that result after any one of a set of unplanned contingency events. The need for such a model arises of course from the SOs' requirement to optimise a performance objective (usually the minimum cost operation of the system[55]) while maintaining a pre-defined level of security. The solution of the SC-OPF model must ensure that, following any of those events, the system does not depart from the 'Normal' operating state (Figure 4-1) – where no network element exceeds its operational limits after a contingency for an extended period of time. This is achieved by considering in the OPF model constraints and decision variables of the "default" (pre-fault) network configuration together with additional constraints (security constraints) and decision variables for contingent (post-fault) configurations. The default configuration,

54 The name given to that model in Chapter 5 is Post-Contingency OPF

55 In the context of the deregulated environment, usually the cost of preventive generation re-dispatch after the market has set the operating point.

often called "base" case, is when all network elements are in service except those that are on scheduled, planned outage.

As it will be explained in more detail in Chapter 4, to achieve the target level of security, SOs can consider the post-contingency corrective rescheduling of controls (for at least some of the contingency cases) or try to secure the system with preventive control rescheduling only[56] [7]. This is reflected in the SC-OPF modelling approaches that can be classified as "corrective" (C-SCOPF) or "preventive" (P-SCOPF) respectively. The SC-OPF problem, in its general form, is a large scale, non-linear, non-convex model with both discrete and continuous variables.

Reference [63] provides models for "benchmark" (problem statement) preventive and corrective SC-OPF formulations that are reproduced here in Model 3-4 and Model 3-5**.**

$$\min_{\mathrm{u}_0} \mathrm{f}(\mathbf{x}_0, \mathbf{u}_0) \tag{3.16}$$

s.t.

$$\mathbf{g}_k(\mathbf{x}_k, \mathbf{u}_0) = \mathbf{0} \tag{3.17}$$

$$\mathbf{h}_k(\mathbf{x}_k, \mathbf{u}_0) \leq \mathbf{0} \tag{3.18}$$

Model 3-4: Benchmark P-SCOPF

$$\min_{\mathrm{u}_0} \mathrm{f}(\mathbf{x}_0, \mathbf{u}_0) \tag{3.19}$$

s.t.

$$\mathbf{g}_k(\mathbf{x}_k, \mathbf{u}_k) = \mathbf{0} \tag{3.20}$$

$$\mathbf{h}_k(\mathbf{x}_k, \mathbf{u}_k) \leq \mathbf{0} \tag{3.21}$$

$$|\mathbf{u}_k - \mathbf{u}_0| \leq \Delta\mathbf{u}_k^{\max} \tag{3.22}$$

Model 3-5: Benchmark C-SCOPF

In Model 3-5 and Model 3-6 the subscript $\mathrm{k} = 0,...,\mathrm{n_k}$ imply that the variables, equality or inequality constraint are for the k^{th} network configuration (where $\mathrm{k} = 0$ corresponds to the base case).

It can be seen that:

- They follow a "direct" modelling approach [103]: the variables and constraints of the base and contingency cases are considered together in the same mathematical model that is submitted to the optimiser once. This is achieved by systematically repeating the variables and constraints of the base case as many times as the contingency cases[57].

56 Except for the controls that automatically respond to the contingency. They are typically voltage/reactive power controls who act locally.
57 Excluding of course network elements that are will be on outage in each of the contingency cases.

- In the P-SCOPF model, the control variables of the base case are used to ensure feasibility of the contingency cases, as expected. In the C-SCOPF model, the network equipment has to be modelled by separate variables for each contingency case.
- The OPF variables for the k^{th} control of the base and each of the contingency case are linked by "coupling" constraints. These limit the allowed movement of the control from the pre-fault (base) operating point and reflect the control movement that can be achieved in the time available for corrective actions.
- In the objective function only state and control variables participate in the base case. This acknowledges the fact that it is the preventive cost/performance objective that really affects the day-to-day operations as it is definitely incurred.
- Constraints (3. 22) determine the level of coupling between the of the base and the post-contingency cases. When $\Delta\mathbf{u}_k^{\max}$ is zero, the C-SCOPF model is equivalent to the P-SCOPF (Model 3-4). When $\Delta\mathbf{u}_k^{\max}$ is infinite the solution of the C-SCOPF model would be equivalent to the single state OPF – one that considers only the base case, as in Model 2-1. It thus sets an upper and lower bound to the objective function value that can be achieved [7].

Model 3-4 and Model 3-5 are provided as problem statement models. More elaborate direct models or approaches based on them have been developed for research or practical applications – examples can be found on reference [104]. However, we can use them as a starting point for the discussion that follows.

SOs would seek to secure as many contingencies as possible with corrective actions only (to not incur any preventive operating cost) but for those that it is not possible, a combination of preventive and corrective actions or, in certain cases, preventive actions only would have to be considered. The criteria for when a case can be considered for corrective actions (for thermal constraints) and the branch flow limits that must apply, vary with the pre-fault operating point (section 4.3.2). This is something a static, direct OPF model does not consider. OPF models must be used together with other modules that perform security analysis or contingency screening.

OPF methods could be used across the spectrum of SO functions and timescales such as in transmission expansion planning, operational planning and (real time) operation [24]. In longer timeframes, it is sufficient for SO engineers to know if a post-contingency configuration can be secured or not and how this affects the preventive operational cost. Decisions made in these timeframes, like the need of "strategic" actions [105] or for investment in transmission capacity do not require the engineers to know the details of the corrective actions – the main driver for them is the preventive operational cost[58]. Furthermore, the inherent uncertainty at these timescales often requires that OPFs are used in a scenario based, probabilistic or parametric framework [59] - where OPF calculations have to be repeated multiple times.

In "real time" timescales[59], SO engineers need to have an "action plan" (a detailed list of preventive and corrective actions) for each of the operational periods (market clearance) and for each of the events the system must be secured against. In the "direct" modelling method of C-SCOPF constraints of the contingency cases are included in the OPF model (together with the coupling constraints) to ensure feasibility of the post-contingency configurations. In the case where the individual controls of each contingency case (variables $\mathbf{u}_k$) are not modelled as penalised deviations from the pre-fault position or they are not priced in the objective function in general, then solutions where the post-contingency controls assume an arbitrary position or a position not in line with any performance measure at the OPF solution may occur.

There is no straightforward way to include controls of the base case (which the SO will definitely need to act on) and of the post-contingency cases (where there are different priorities/requirements and will only be applied in the event of the contingency[60]) in the same objective function. The OPF model is agnostic to that and optimises the preventive and corrective controls together, on the basis of the objective function coefficients. Practical approaches that use direct modelling may consider pricing in the objective function the deviation of controls from their pre-fault positions, the violation of coupling constraints (3. 22) or the violation of branch flow constraints (3. 21). This could improve the post-contingency part of the OPF solutions although it will not necessarily make it fit for purpose. For better results, one may consider solving the contingency case as a separate single state OPF problem.

Another issue that must be considered when using a direct model is the size of the OPF problem. In their simplest form, direct models repeat all the base case problem variables ("columns") and constraints ("rows") as many times as the contingency cases. In real world synchronously interconnected power systems (or even large national systems) the size of the problem will soon become intractable. Reference [63] states that including the constraints of many post-contingency cases in the OPF model increases the complexity of the computations due to the shrinkage of the feasible region and can lead to algorithmic/numerical issues when

58 This can be easily understood as the probability of a transmission forced outage (that will necessitate corrective actions) is low and hence the expected cost of the corrective actions is very small relative to that of the preventive ones. Further discussion is provided in section 4.2.2
59 And by extension, in "close" to real time timescales: at the operational planning phases that successively feed into the real time operation.
60 Section 3.4 provides further insight about the requirements and priorities.

the interior point method is used, even if most of these constraints do not limit the optimal solution.

3.2.1 The complete preventive SC-OPF model

Model 3-6 extends the model developed previously for the re-dispatch of active power controls (Model 3-3) to include constraints of the contingency cases. Model 3-6 is a security constrained OPF model for the preventive re-dispatch of active power controls. As written, the model can be used only for contingencies of network branches.

$$\min \mathrm{f(x)} \;=\; \tag{3.23}$$

$$\mathbf{c}_{\mathrm{bmu}}^{+}\mathbf{x}_{\mathrm{bmu}}^{+} + \mathbf{c}_{\mathrm{bmu}}^{-}\mathbf{x}_{\mathrm{bmu}}^{-} + \mathbf{c}_{\mathrm{qb}}^{+}\,\mathbf{x}_{\mathrm{qb}}^{+} + \mathbf{c}_{\mathrm{qb}}^{-}\,\mathbf{x}_{\mathrm{qb}}^{-} +$$

$$\mathbf{c}_{\mathrm{ic}}^{+}\,\mathbf{x}_{\mathrm{ic}}^{+} + \mathbf{c}_{\mathrm{ic}}^{-}\,\mathbf{x}_{\mathrm{ic}}^{-} + \mathbf{c}_{\mathrm{dc}}^{+}\,\mathbf{x}_{\mathrm{dc}}^{+} + \mathbf{c}_{\mathrm{dc}}^{-}\,\mathbf{x}_{\mathrm{dc}}^{-}$$

s.t

$$-\mathbf{l}_{\mathrm{max}} \le \mathbf{l}_{\mathrm{init}} + \tag{3.24}$$

$$\mathbf{A}_{\mathrm{G}}\,\mathbf{x}_{\mathrm{bmu}}^{+} - \mathbf{A}_{\mathrm{G}}\,\mathbf{x}_{\mathrm{bmu}}^{-} + \mathbf{A}_{\mathrm{Q}}\,\mathbf{x}_{\mathrm{qb}}^{+} - \mathbf{A}_{\mathrm{Q}}\,\mathbf{x}_{\mathrm{qb}}^{-} +$$

$$\mathbf{A}_{\mathrm{I}}\,\mathbf{x}_{\mathrm{ic}}^{+} - \mathbf{A}_{\mathrm{I}}\,\mathrm{x}_{\mathrm{ic}}^{-} + \mathbf{A}_{\mathrm{D}}\,\mathbf{x}_{\mathrm{dc}}^{+} - \mathbf{A}_{\mathrm{D}}\,\mathbf{x}_{\mathrm{dc}}^{-}$$

$$\le \; \mathbf{l}_{\mathrm{max}}$$

$$-\mathbf{l}_{\mathrm{max}}^{k} \le \mathbf{l}_{\mathrm{init}}^{k} + \tag{3.25}$$

$$\mathbf{A}_{\mathrm{G}}^{k}\,\mathbf{x}_{\mathrm{bmu}}^{+} - \mathbf{A}_{\mathrm{G}}^{k}\,\mathbf{x}_{\mathrm{bmu}}^{-} + \mathbf{A}_{\mathrm{Q}}^{k}\,\mathbf{x}_{\mathrm{qb}}^{+} - \mathbf{A}_{\mathrm{Q}}^{k}\,\mathbf{x}_{\mathrm{qb}}^{-} +$$

$$\mathbf{A}_{\mathrm{I}}^{k}\,\mathbf{x}_{\mathrm{ic}}^{+} - \mathbf{A}_{\mathrm{I}}^{k}\,\mathrm{x}_{\mathrm{ic}}^{-} + \mathbf{A}_{\mathrm{D}}^{k}\,\mathbf{x}_{\mathrm{dc}}^{+} - \mathbf{A}_{\mathrm{D}}^{k}\,\mathbf{x}_{\mathrm{dc}}^{-}$$

$$\le \; \mathbf{l}_{\mathrm{max}}^{k}$$

$$\forall\, k \in \{1,\ldots,\mathrm{n}_k\}$$

$$\sum_{g} x_{\mathrm{bmu}_g}^{+} - \sum_{g} x_{\mathrm{bmu}_g}^{-} + \sum_{t} x_{\mathrm{ic}_k}^{+} - \sum_{t} x_{\mathrm{ic}_t}^{-} = 0 \tag{3.26}$$

$$\mathrm{x}_{\mathrm{dc}_{\mathrm{north}_j}}^{+} - \mathrm{x}_{\mathrm{dc}_{\mathrm{north}_j}}^{-} + \mathrm{x}_{\mathrm{dc}_{\mathrm{south}_j}}^{+} - \mathrm{x}_{\mathrm{dc}_{\mathrm{south}_j}}^{-} = 0 \;\forall\, j \in \{1 \ldots \mathrm{n}_{\mathrm{dc}}\} \tag{3.27}$$

$$0 \le \mathbf{x}_{\mathrm{bmu}}^{+} \le \mathbf{ub}_{\mathrm{bmu}}^{+}\,, 0 \le \mathbf{x}_{\mathrm{bmu}}^{-} \le \mathbf{ub}_{\mathrm{bmu}}^{-} \tag{3.28}$$

$$0 \le \mathbf{x}_{\mathrm{qb}}^{+} \le \mathbf{ub}_{\mathrm{qb}}^{+}, 0 \le \mathbf{x}_{\mathrm{qb}}^{-} \le \mathbf{ub}_{\mathrm{qb}}^{-},$$

$$0 \le \mathbf{x}_{\mathrm{ic}}^{+} \le \mathbf{ub}_{\mathrm{ic}}^{+}\,, 0 \le \mathbf{x}_{\mathrm{ic}}^{-} \le \mathbf{ub}_{\mathrm{ic}}^{-},$$

$$0 \le \mathbf{x}_{\mathrm{dc}}^{+} \le \mathbf{ub}_{\mathrm{dc}}^{+}, 0 \le \mathbf{x}_{\mathrm{dc}}^{-} \le \mathbf{ub}_{\mathrm{dc}}^{-}$$

Model 3-6: Preventive SC-OPF model

where

$\mathbf{l}_{\mathrm{max}}^{k}, \mathbf{l}_{\mathrm{init}}^{k}$	$\mathrm{n_l}$ x 1 vectors with the thermal ratings of braches and the initial branch flow (‘From’ side) respectively for the *k*th contingency

case. Thermal ratings could be continuous or short-term limits as applicable.

$\mathbf{A}_{\mathrm{G}}^{k}$	$\mathrm{n_l}$ x $\mathrm{n_c}$ matrix of PTDFs for the generator decision variables for the kth contingency case
$\mathbf{A}_{\mathrm{Q}}^{k}$	$\mathrm{n_l}$ x $\mathrm{n_q}$ matrix of QBDFs for the QB decision variables for the kth contingency case
$\mathbf{A}_{\mathrm{I}}^{k}$	$\mathrm{n_l}$ x $\mathrm{n_{ic}}$ matrix of PTDFs for the interconnector decision variables for the kth contingency case
$\mathbf{A}_{\mathrm{D}}^{k}$	$\mathrm{n_l}$ x $(2 * \mathrm{n_{dc}})$ matrix of PTDFs for the decision variables modelling the embedded HVDC links for the kth contingency case

and all other notations as per Model 3-3.

In Chapter 5[61], Model 3-6 is used to find the minimum cost preventive actions that ensure branch flows stay within the specified limits for all considered branch contingencies.

3.3 Limiting the volume of post-fault generation re-dispatch

If the OPF model is used to calculate corrective actions that will be applied after an unplanned transmission fault outage, a limit should be set to the total volume of power constrained through generation and interconnector Bid acceptances for the reasons explained in this section.

Renewable energy generators – such as larger windfarms – are connected to the network through power electronic converters. They can reduce their output quickly using a combination of electrical and mechanical means. Thermal generators – such as Combined Cycle Gas Turbine (CCGT) power stations – are, for the most part, located in areas of the GB network where there is sufficient transmission capacity. They can change their output at a slower rate due to thermodynamic or control system restrictions. The exact rate varies by the power station age and technology [106].

Following a transmission fault, the first priority of the SO power system engineers is to issue Bid acceptances in order to reduce the flow of the overloaded branches. That way they minimise the time the branches are exposed to increased loading (even if it is still within the short-term rating that applies). The acceptance of the Offers needed to replace the lost generation follows right after.

Due to the difference in instruction times and in the ramp down rates of renewable generation, when compared the ramp up rates of thermal generators, the system must rely on reserve energy to maintain the balance of generation and demand for some of the time between the

61 The name given for that model in Chapter 5 is Preventive SCOPF (P-SCOPF)

start and the completion of the re-dispatch actions. The contracted reserve[62] will be used to avoid unacceptable frequency conditions.

The SQSS [4] defines that the volume of reserve procured at any given period must be sufficient to ensure that if the max possible loss of infeed take place – after a set of events also described in the same document – no unacceptable frequency conditions would follow. It also goes on to define what the Normal Infeed Loss Risk and Infrequent Infeed Loss Risk (in MW) should be. These two values set the upper limits that should always be adhered to: during the transmission expansion stage, when designing new generation connections or when planning for equipment outages for network access during operational planning. In practice, the volume of generation lost after a transmission fault at a given period could be less that the Normal or Infrequent loss as it depends on the output of the largest (group of) generators running.

An additional linear constraint can be added to the OPF model to limit the volume of generation and interconnections re-dispatch. Depending on the use of the model, this could be the reserve limit set for a particular day or one of the statutory limits.

$$\sum_{g} x_{\mathrm{bmu}_g}^{-} + \sum_{t} x_{\mathrm{ic}_t}^{-} \leq \mathrm{MW}_{\mathrm{reserve}} \tag{3.29}$$

3.4 Using a limited number of controls in the OPF solution

3.4.1 Background

One of the long documented shortcomings of the OPF method [66] is that it uses a larger number of controls in the optimal solution than that deemed necessary for practical applications. This is inherent to the mathematical optimisation principle: the optimiser will always try to find the solution that provides the minimum possible objective value for the given set of constraints. The optimiser will use (almost) all the available controls even if the incremental improvement in the objective function – when compared to a solution that uses a smaller number of controls – is negligible.

This shortcoming has further implications for the adoption of OPF methods by SOs [49][107]. Power system engineers often see the solution suggested by the OPF methods as coming out of a "black box". Control actions are not ranked by importance and the impact each action has on removing the constraint violation is not obvious. The impact is not related to the magnitude of the control movement. Each control participates towards improving the objective function

62 Reserve in the GB system includes 'fast reserve' which is equivalent to the 'secondary frequency response' in other SO areas.

and enforcing the constraints at the same time in a non-separable way. All control actions have to be applied together for the solution to be valid. Even actions of smaller magnitude or of controls with little electrical sensitivity are needed as omitting them could result to an infeasible outcome or one with a more expensive objective value/performance metric [65].

SO engineers always seek a defined or small number of control actions [107]. When the system is at a post-contingency state – i.e. the OPF is used to calculate corrective actions – there is limited time for control actions. In most systems, OPF methods are not used in closed loop implementations and the calculated actions must be applied manually[63]. Certain criteria must be met so that the actions are 'fit for purpose': engineers must be able to implement them using the existing communication, control and supervision systems within a given amount of time. When the OPF is used to calculate preventive actions – SOs are also incentivised to seek a smaller number of control actions if possible. In an active power re-dispatch OPF problem, control actions typically involve action on third-party (non-SO) equipment.

The above are relevant not only when OPF methods are used in real time applications but when used in the operational planning and transmission expansion planning phases. The output of these two phases eventually feeds to the day-to-day operation. The number of controls that are used in a post-contingency OPF calculation could determine whether certain contingency cases are 'correctable' or not affecting decisions about transmission outages planning or transmission investment.

Reference [107] uses the graph in Figure 3-2 to demonstrate the trade-off relationship between the number of controls allowed to moved and the objective value. It can be seen that there is a minimum number of controls that are required to satisfy constraints and ensure feasibility (Nmin in Figure 3-2) and a maximum number that the optimiser would use if all the controls were available (n). There is also a number beyond which there is no practical improvement in the objective value (Nc).

63 Manual instruction is true for all active power control actions (preventive or corrective) except a limited number of automatic controls such as special protections schemes (intertrips).

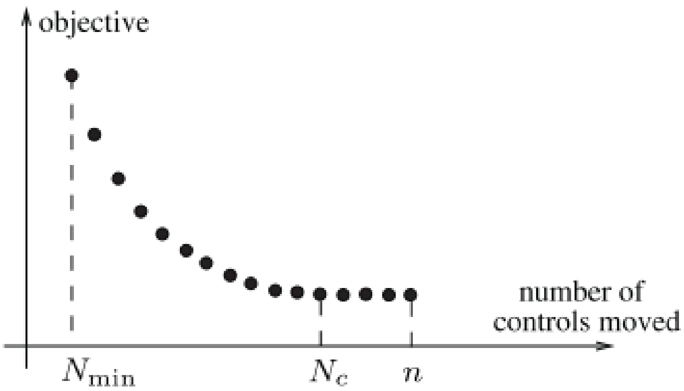

Figure 3-2: Objective function versus the number of controls allowed to move. Source: [107]

SOs require OPF solutions where no more than Nc controls are used. Depending on the application, some further derogation of the objective value – i.e. a solution with less than Nc controls – could be acceptable [108]. Controls that are only required in solutions where the number of controls used is greater than Nc should be considered ineffective and suppressed. As a planning tool, the trade-off curve can provide useful insight about the importance of each control action by comparing the individual controls used in each solution point vs the objective value achieved.

Each point in the curve requires the solution of a separate OPF problem that is (in its general form) a problem with integral constraints. References [107]–[109] explore different aspects of this issue: mathematical formulations that turn the integral constraints into equivalent problems or ways to approximate Nc without the need to solve/draw many point in the curve.

Other approaches rely on specifying beforehand the controls allowed to participate in the optimisation. This can be done either by the user's knowledge of the system or by employing heuristics to remove controls whose effectiveness towards the overloaded branches is below a threshold. Another technique is to solve an OPF problem using the full set of controls first and then select a subset of the controls, based on heuristics and the information available at the solution.

In the following sections we will explore different aspects of the issue and propose a method for selecting a limited set of controls.

3.4.2 Using the minimum number of controls

This objective becomes more relevant when calculating actions for post-contingency applications. Using the minimum set of actions can contribute towards reducing risk to the extent that equipment is exposed to abnormal loading for the shortest possible amount of time. It can also contribute towards reducing the 'complexity' of operation to the extent that fewer pieces of equipment will be used for actions and potentially fewer transmission elements will be affected by the control actions[64].

The following OPF model can be used to generate the minimum number of actions:

$$\min \quad \mathrm{f(x)} + \sum_{1}^{\mathrm{n_c}} \mathrm{s}_i \tag{3. 30}$$

s.t.

$$\mathbf{g}(\mathbf{x}, \mathbf{u}) = \mathbf{0} \tag{3. 31}$$

$$\mathbf{h}(\mathbf{x}, \mathbf{u}) \leq \mathbf{0} \tag{3. 32}$$

$$\mathbf{x\_min} \leq \mathbf{x} \leq \mathbf{x\_max} \tag{3. 33}$$

$$\mathrm{s}_i * \mathrm{u_{min}}_i \leq \mathrm{u}_i \leq \mathrm{s}_i * \mathrm{u\_max}_i \quad \forall\, i = 1, \ldots, \mathrm{n_c} \tag{3. 34}$$

$$\mathrm{s}_i \in \{0,1\} \;\; \forall\, i = 1, \ldots, \mathrm{n_c} \tag{3. 35}$$

Model 3-7: OPF using the minimum number of control actions

where $\mathrm{n_c}$ is the total number of controls.

Model 3-7 is only provided for the discussion of this section and is not used for the results presented in Chapter 5. The objective uses a term that helps to minimise the number of controllers moved. It should be noted that, in most cases, the objective of a model like Model 3-7 would combine the term that quantifies the number of controllers moved – second term of (3. 30) – with one that quantifies the cost of generation re-dispatch – f(x) as in (3. 11) of Model 3-3.

In Model 3-7, s_i is a set of binary activation variables - one for each of the $\mathrm{n_c}$ control variables. When s_i is zero the upper and lower bounds of the control variable become zero and the control is not used. The performance measure (objective) in this case is the sum over the activation variables that acts as a count of the controls used. In its general form, Model 3-7 is a mixed integer non-linear programming (MINLP) model which is computationally expensive to solve for a large number of operational snapshots. Reference [108] provides an approximate method where the variable s_i and corresponding function (3. 34) for each variable u_i is replaced by a smooth nonlinear continuous function. Alternatively, if the OPF model is using the DC approximation, as in Model 3-3, it becomes a MILP model.

64 In this context, the 'complexity' of implementing a set of actions can be thought of as the number of assets that need to be acted upon (i.e. number of QBs and generators) but also as the overall effect that control actions have on redistributing the network flows – including on parts of the network further away from the constraint.

Having a performance measure based solely on the minimum number of controls is not without its own problems. The OPF Model 3-7 is agnostic towards the properties of the individual controls selected. As control actions do not all take the same time to execute, it is not guaranteed that the minimum set of actions is also the quickest to implement.

3.4.3 Using a pre-defined number of controls

Another commonly used objective is to limit the maximum number allowed controls to a user defined value [110]. While this may seem like an oversimplification, this objective can be important for practical applications. SOs operate using a set of guidelines that cascade from the high level planning and operation standards to the more detailed "business procedures" or methodologies and cover the different phases of SO's activities. Standards can be thought as [111], [112] a set of events of the SO must consider and be prepared for and a set of consequences that must be avoided. In defining the standards and supporting guidelines, an assessment was made on what is an acceptable level of risk in terms of: the probability of an event happening; the consequences that can be accepted or not; and the mitigation measures that can be considered.

When a OPF model is used to calculate actions for post-fault generation re-dispatch, using the control re-dispatch limits defined in these guidelines ensures that the operations always stay within a pre-defined region of acceptable risk. It also makes sure that the calculated corrective actions are fit for purpose and can indeed be applied if necessary. That way, cases that are marked as 'correctably secure' in a security assessment that uses the OPF model are indeed so (section 4.3.2).

The activation variables technique can be used to adapt Model 3-3 as follows. The equations (3. 15) of Model 3-3 that set the bounds of each control, must be replaced by:

$$\begin{gathered} 0 \leq \mathrm{x}^{+}_{\mathrm{bmu}} \leq \mathrm{s}^{+}_{\mathrm{bmu}_g} * \mathrm{ub}^{+}_{\mathrm{bmu}}\,,\ 0 \leq \mathrm{x}^{-}_{\mathrm{bmu}} \leq \mathrm{s}^{-}_{\mathrm{bmu}_g} * \mathrm{ub}^{-}_{\mathrm{bmu}} \\ 0 \leq \mathrm{x}^{+}_{\mathrm{qb}} \leq \mathrm{s}^{+}_{\mathrm{qb}_q} * \mathrm{ub}^{+}_{\mathrm{qb}}\,,\ 0 \leq \mathrm{x}^{-}_{\mathrm{qb}} \leq \mathrm{s}^{-}_{\mathrm{qb}_q} * \mathrm{ub}^{-}_{\mathrm{qb}} \end{gathered} \tag{3. 36}$$

$$\begin{gathered} \sum_{1}^{\mathrm{n_g}} \mathrm{s}^{+}_{\mathrm{bmu}_g} \leq \mathrm{max}^{\mathrm{offer}}_{\mathrm{bmu}} \\ \sum_{1}^{\mathrm{n_g}} \mathrm{s}^{-}_{\mathrm{bmu}_g} \leq \mathrm{max}^{\mathrm{bid}}_{\mathrm{bmu}} \\ \sum_{1}^{\mathrm{n_{qb}}} \mathrm{s}^{+}_{\mathrm{qb}_q} + \sum_{1}^{\mathrm{n_{qb}}} \mathrm{s}^{-}_{\mathrm{qb}_q} \leq \mathrm{max}_{\mathrm{QB}} \end{gathered} \tag{3. 37}$$

$$s_{\mathrm{bmu}_g}^{+}, s_{\mathrm{bmu}_g}^{-}, s_{\mathrm{qb}_q}^{+}, s_{\mathrm{qb}_q}^{-}, s_{\mathrm{ic}_t}^{+}, s_{\mathrm{ic}_t}^{-}, s_{\mathrm{dc}_d}^{+}, s_{\mathrm{dc}_d}^{-} \in \{0,1\} \tag{3. 38}$$

$$\begin{gathered} \forall\, g = 1, \dots, \mathrm{n_g} \\ \forall\, q = 1, \dots, \mathrm{n_{qb}} \end{gathered} \tag{3. 39}$$

Note that the activation variables are no longer used in the objective function so the objective is that of minimising the cost of generation re-dispatch – as in equation (3. 11) of Model 3-3. They are used in linear constraints that limit the number of controls (activation variables) that can be used to a user defined value – $\max_{\mathrm{bmu}}^{\mathrm{offer}}$, $\max_{\mathrm{bmu}}^{\mathrm{bid}}$ or $\max_{\mathrm{QB}}$, (3. 37). A separate constraint must be used for each type of control and/or direction of travel (positive or negative counterpart decision variable. Constraints (3. 37) limits the number of QB transformers used or BMUs used for Bids and Offer by the optimiser (number of controllers) – not the number of tap changes or the volume of MW re-dispatched.

3.4.4 Selecting the most effective controls

Background

In this section we will develop a new method for solving an OPF problem using a limited number of controls. The rationale for it is based on the following observations:

- The branches that are overloaded at the initial operating point (OPF start) are not necessarily the ones that will be the ‘active’[65] constraints at the OPF solution.
- Preventive control actions are not calculated on a contingency by contingency basis but for all of them at the same time. Often different contingencies result in the same branch overload (constraint) or, actions targeted for one of the constraint could be effective for others since they affect flows on other parts of the network (i.e. downstream in the direction of flow).
- Any method for limiting the number of controls based only on information from the initial operating point cannot fully consider the interactions described above and approaches that solve the OPF problem multiple times are not computationally attractive.

65 Active or binding constraints are the ones that restrict the optimal solution. In the following, we will use the term to refer to branch flow constraints only – not decision variable bounds.

Process steps

The objective is to define a reduced set of controls that, when used in the OPF, can approximate the "all controls" OPF solution to a degree that is sufficient for practical applications. The end to end process is depicted in Figure 3-3 and the individual steps are detailed below.

In step 1 (Figure 3-3) we solve an OPF model that uses all the available controls. This allows the identification of the constraints that are active at the optimum solution (step 2). To approximate that solution, the controls selected must be the most effective towards the active constraints. In a SC-OPF model, that includes constraints of both the "default" (pre-fault) network configuration and the contingent (post-fault) configurations in the same model, the active constraints could of course belong any of the configurations and should be selected as necessary[66].

In step 3, we rank the active constraints in the order of their contribution towards restricting the power flows. One useful metric is the "shadow prices" or Lagrange multipliers of the optimal solution. The shadow price of a particular constraint is the change in the optimal objective function value achieved by a unit increase in the "right hand side" of the constraint - the capacity of the branch– if all other problem data stay the same. It, and other OPF sensitivities, are readily available at the solution of the OPF problem. The shadow price of a constraint that is not active at the optimum solution is zero [113].

Shadow prices indicate where investment in capacity should be directed to further reduce the objective value but may not be sufficient, on their own, to provide insight on the contribution of each branch/constraint towards the current solution. For that we can use the "congestion rent delta" associated with the branch [17]:

$$\text{cong. rent delta} = \text{shadow price} * \ |\text{flow final} - \text{flow initial}| \qquad (3.40)$$

where the initial branch flow (MW) is available from the power flow solution at the initial operating point (marker dispatch) and the final branch flow can be found from a power flow solution at the "all controls" OPF solution. We rank the active constraints in order of decreasing congestion rent delta.

66 Even if two active constraints model the same network branch under different configurations (contingency cases).

We would like to keep in the reduced set (U in Figure 3-3) the controls that are the most effective towards the active constraints, with priority given to the controls that are effective towards the constraints with the highest congestion rent delta.

For that, we iterate through the active constraints, in decreasing congestion rent order (steps 4 to 9). For each constraint we cluster the controls into mutually exclusive groups (sets) based on their effectiveness[67] – their ability to influence the power flow on the constraint selected at the current iteration. In the context of SC-OPF, the sensitivities used for the grouping must of course correspond to the network configuration that the active constraint[68] arises from. There is more than one way the grouping can be done.

Either of these well-known grouping techniques can be used:

- K-means clustering: groups the controls into k clusters so that the effectiveness of all controls in a group are "close" to each other, as measured by the difference between pairs of them. K-means iteratively updates the "group representatives" and then the "group assignments" of each cluster until the "clustering objective" stops improving. The initialisation of the algorithm – the initial choice of group representatives and the value of k – are user defined and could affect the final allocation of controls [114].
- Splitting the controls into sets using percentiles: the P^{th} percentile value is the number that puts at least P % of the effectiveness values at that number or below and at least $100 - $ P % of the values at that number or above [115].

At the end of step 6, all the controls will be divided into four sets of similar effectiveness towards the constraint of the current iteration (P1 to P4 in Figure 3-3). For the results presented in Chapter 5 we used the percentiles technique and we split the controls into the four set using the 75^{th}, 50^{th} and the 25^{th} percentiles of effectiveness of the full set of controls. That means that the P1 group will contain the controls whose effectiveness is higher than the 75% percentile, P2 those whose effectiveness is between the 75% and 50% percentile, P3 those whose effectiveness is between the 50% and 25% percentile and P4 the least effective controls that have effectiveness less than the 25% percentile.

Further, we include sets P1 and P2 in the reduced set (U) for the two highest rank constraints but only P1 for the remainder. This is done because it was found that the two highest rank constraints have proportionally a higher congestion rent value than the ones that follow so

67 These are the PTDFs and QBDFs presented in 3.1.2
68 This means that if the active constraint is of a contingency case the sensitivities that correspond to that post-contingent network configuration must be used.

using controls from the first two sets of effectiveness for the two highest rank constraints is important for achieving a reduction in the objective value (in the study setup of section 5.1).

Note than none of the above clustering techniques (K-means or percentiles) pre-determines the number of controls that end up in each set. That depends on the distribution of controls' sensitivities towards the selected constraint – determined by the network connectivity and configuration only.

The grouping of controls (in step 6) must be applied separately for each type of control action (i.e. QB tapping, bidding off generators and offering on generators). This is necessary as the effectiveness values of QBs and generators cannot be directly compared and different operational considerations apply to them. Further, many generators can only be re-dispatched to one direction[69] so the available controls' effectiveness to choose from is different for bidding and offering actions.

In each iteration, we need to select the set(s) of control to include in the reduced set – U in Figure 3-3. Apart from the controls of the most effective set (P1) the user can select to add controls of other, less effective, groups into U.

If the method is used in the context of C-SCOPF method (where the OPF model calculates preventive and corrective actions), the sets P1…P4 for a given iteration could contain OPF controls that model the same physical assets but under different network states – i.e. they are modelled by separate decision variables. In that case they need to be added to set U as individual, separate controls/decision variables – one for each network contingency. In the case of a preventive only SC-OPF – as in Model 3-6 – where there is only one set of controls/decision variables, they will be of course added to U once.

Finally, once all the active constraints have been examined, and set L is empty, the process stops – step 10. The reduced set of controls, U, can be used in the final OPF calculation.

69 Because they are already at their upper or lower operational limit.

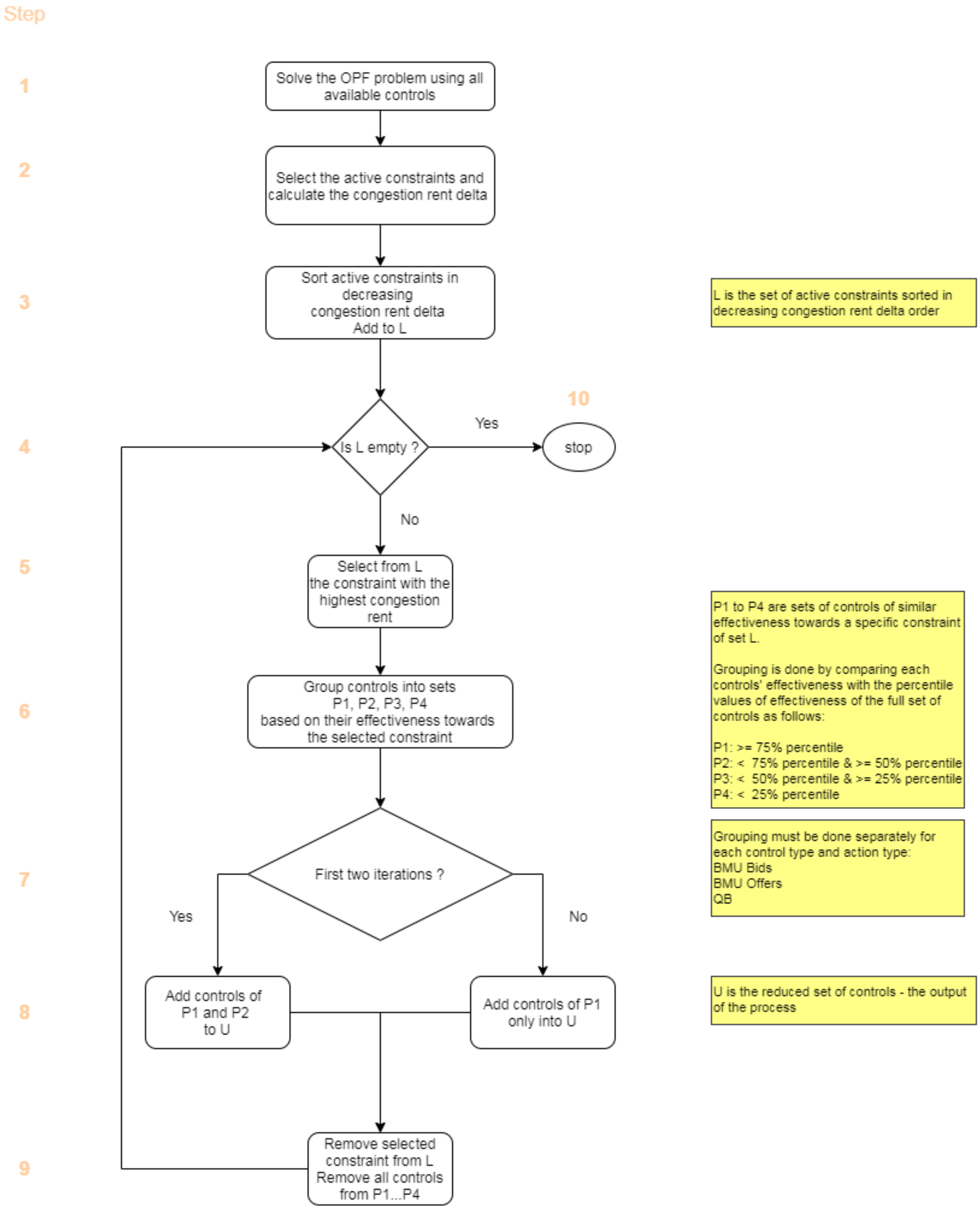

Figure 3-3: Process for selecting the most effective controls

3.5 Power flow control coordination across system borders

Coordination of power flow control devices in large interconnected systems is multi-perspective issue. The Central West Europe (CWE) system is operated by multiple TSOs, each ultimately responsible for the security of its own control area. The interconnection capacity between neighbouring countries is finite and it has been noted that the increase of wind capacity and the variability of wind output can make the ex-ante allocation of day-ahead cross-border capacity – based on the previously used Available Transfer Capacity (ATC) methodology – for use by the market challenging [47]. Further, the TSOs in neighbouring countries could at times be applying different assumptions when calculating the cross-border ATC such as the application of custom security margins or assumptions regarding what corrective actions can be applied. Preventive or corrective actions executed by TSOs in one area could have an unwanted effect in other parts of the network, including reducing the cross-border capacity between third-party counties if not carefully coordinated.

In large interconnected systems, network flows do not always follow the path anticipated by the market transactions. One well-studied example is that of the Netherlands and Belgium that in early 2000's used to receive increased north-to-south flows through their networks originating from market transactions they were not involved in. The unwanted, loop flows reduced the planned cross border TTC of these countries and even increased the loading of circuits within their borders. Eventually that limited the amount the wind power that could be accommodated in the system. Several Phase-shifting transformers were installed in the borders of the Netherlands, Belgium and Germany to regulate the flows. Initial experience from using these devices and the strategies employed for their control can be found in references [47], [38] and in Chapter 6 of [37].

Earlier research focused on algorithms for the effective use of PSTs and other active power control devices (such as embedded HVDC links) in the context described above. Part of that work includes [116], where a linear least squares optimisation problem is used to find the PST angle settings that make the relative loading of the Dutch-German border crossing circuits as equal as possible. Some consideration for using a closed loop controller based on the linear least squares scheme and offline simulation results are presented.

In [117], the authors considered the operational objectives of minimising the flow or maximising the margin across a number of "critical branches" solved using a "direct" Quadratic Programming preventive SC-OPF model. In [118], it was extended with a process that tries to reduce the PST phase angle changes between successive dispatch periods by introducing an objective function difference threshold. Reference [25] used concepts and modelling similar to the latter two references and it considered the objectives of minimising the loading of the highest loaded critical branch and that of maximising wind infeed of a specific region of CWE. It was tested against data from one month of the CWE network operation.

Regional coordination centres, such as Coreso [119], bring together the day ahead generation and demand forecasts of the TSO of a broader area into a common grid model to provide region wide security analysis, a process called Day Ahead Congestion Forecasting. They also propose coordinated preventive or remedial actions where necessary, using the available PSTs and assist TSOs with intra-day operational planning.

In 2015, a Flow Based Market Coupling (FBC) methodology for the coupling of the day-ahead markets of CWE countries was introduced [120]. In 2022, FBC was extended to cover 13 countries (16 TSO areas) in total [121]. FBC replaced the ATC methodology in the day-ahead market clearing timeframe but ATC based market coupling is still in use at the future markets or intraday timeframes [122].

The FBC method considers as critical branch/critical contingency combinations lines both at the interface of market zones (i.e. tie-branches between national systems) and a number of selected lines within the individual lines (TSO selected) so it is regarded as able to reproduce more accurately the available transfer capacity between zones than the ATC method that does not consider the internal lines and had to use higher safety margins [123].

The method requires two sets of parameters as input for the day-ahead market clearing/coupling, the Zonal PTDFs and the Remaining Available Margin (spare security constrained line capacity that can be used by day ahead market). Calculating both of these requires that an expected/forecasted market dispatch is available. A two-day ahead (D-2) congestion forecast is used for that purpose. It is noted that the exact way (both in mathematical terms but also as an applied process) these parameters are calculated [124] [125] or which critical branch/critical contingencies are selected [126] has a direct impact on the results of the market coupling.

The PSTs installed in the CWE area can be used to increase the Remaining Available Margin for certain zone to zone exchanges [127]. This is achieved by using the PSTs for remedial (corrective) actions or through the coordination of their pre-fault tap setting. Reference [120] states that PST taps are initially set to zero/neutral tap in the initial FBC parameter calculation phase (at the D-2) but preventive tap settings are selected by coordination between the CWE

TSOs at the qualification and verification of the FBC parameters phase that follows before they are used in the market clearing.

While the above enhance the market integration and coordination of TSO operations in the short term, it is noted that further integration is necessary in terms of future market coupling, cross-border investment planning, asset ownership, financing and cost allocation [128] or the use of a FBC type of methodology in investement evaluation [129]. The “investment paradox” (section 2.2.3 and [47]) becomes relevant as investment in one TSO area is sometimes required to relieve congestion in another.

4 Coordination of QB tap settings in the context of preventive and corrective operation

This chapter is made of three parts. The first part (section 4.1) reviews a number of approaches for limiting the size of the "direct" SC-OPF problem (introduced in chapter 3) including the use of alternative formulations through decomposition or iterative methods. The second part (section 4.2) sets out the requirements for the QB coordination framework. What is it that "coordination" is trying to achieve, what should the objective be in the different states that the power system can find itself in and what are the outputs that SO engineers require are some of the questions considered. The final part (section 4.3) develops the proposed QB coordination framework based on the requirements of section 4.2 and some of the learnings of section 4.1.

4.1 Iterative and decomposed OPF methods for corrective security

In Chapter 3, an SC-OPF model for coordinating active power controls' settings using the "direct" method – where the constraints of the base case (pre-fault configuration) and each of the security cases (post-fault configurations) are included in the same OPF model and simultaneously solved – was developed and some of its shortcomings were explained. "Iterative" or "decomposed" OPF methods/frameworks try to overcome them and produce a solution that is more fit for purpose and a process that is more tractable. In this section we will review these approaches.

Iterative or decomposed methods in general break down the overall operational or planning objective/application that the SC-OPF must address into steps and iterate between the solution of a "main" SC-OPF model – that could be either of the preventive or the corrective variation – and additional modules or sub-problems. The latter are based on power flow or OPF and provide information about the current/next iteration of the process. They are used to validate the existing solution or decide if additional contingency cases need to be added in the main problem for instance.

4.1.1 Limiting the size of the problem

One class of approaches uses heuristics to reduce the size of the "main" model and limit the number of optimisation variables (columns) or constraints (rows) that are included. The rationale for these methods is based in the following considerations.

Not all contingencies produce network constraints that limit the SC-OPF optimal solution

First, not all contingencies produce network constraints that are ‘active’ at the SC-OPF optimal solution and, those that do typically only contribute a limited number of constraints to the ‘active’ set[70]. To understand this, we can use the concept of the transmission boundary – that was introduced in section 2.2.2 – for an analogy. A transmission boundary separates the network into two distinct areas and is crossed by several circuits. It is expected that, for a given power transfer level, a contingency fault in any of the crossing circuits[71], could result in the overload of the same network constraint – the “weak” link of the boundary/area. This would happen due to the following combined: the difference in the sharing of power flows [72] and in the capacities between the circuits that cross the boundary. Different contingencies would of course cause the weak link branch to overload to a different extent.

When SO engineers plan for generation re-dispatch actions, one approach is to target the “worst” boundary contingency – the one that causes the highest overload – first. Securing the system against it is likely to be sufficient so that the network is secured against the other contingencies of the boundary/area as well[73]. Further, this principle is extended and used on a system wide basis, where applicable. The different areas/boundaries of the network – worst contingency and limiting component (constraint) combinations – and the ways they interact – e.g. how power flows through consecutive areas – are considered together so that the most efficient or cost effective control actions overall are decided. Knowledge of specific contingency/constraint combinations only – the ones that need to be targeted – together with their consequences and their interactions would lead to the same active power controls action plan as when considering the larger set of all credible contingencies – and the same level of security would be attained. Note for instance how thermal constraint cost is attributed to only a handful of critical contingencies (boundaries) in [130].

In a similar way, finding the contingency cases that would produce ‘active’ constraint at the SC-OPF optimal solution of the direct model – hereafter called ‘critical’ contingencies – would suffice to obtain the same solution and avoid the computational complexity of solving the direct model.

70 The active set of a SC-OPF solutions contains all constraints that limit the optimal SC-OPF solution. It refers to the optimisation problem constraints, not network constraints (branches or other elements). The same network branch could be an active optimisation constraint under more than one contingencies. Some decision variables bounds will also be ‘active’ at the optimal solution. For the remainder of the section we refer to branch flow constraints only.
71 Or of one of the circuits in the vicinity of the boundary.
72 Uneven or not favourable flow sharing can occur due to the prevailing/expected generation dispatch, due to the network structure - e.g. having parallel circuits lowering the effective impedance in one side of the boundary - or both.
73 In the case when it is not sufficient, the initial set of control actions serves as a starting point.

The above led to the development **iterative contingency selection methods**, where only a subset of the credible contingency cases is initially included in the SC-OPF problem. That initial set, populated from user experience or using a security analysis module, is extended in every iteration to include more contingencies that can potentially be critical, until all of them have been identified.

The impact of a contingency is generally limited in a certain area of the network

Second, the effect of each contingency is thought to be limited in the area of the network in the proximity of the contingency. The prerequisite conditions for this to apply, such as meshed network connectivity and high branch reactance relative to resistance are typically found in the high voltage transmission systems. It is implied that the violations (branch limit, node voltage limit or node voltage step change for instance) but also the controls likely to be used in response to the contingency are all contained in that area.

This is true in a number of occasions. Regarding thermal violations, using the boundary concept, where a contingency of a branch that crosses the boundary causes the overload in one of the remaining branches, it can be easily demonstrated. Regarding the locality of controls, due to the high reactance[74] of high voltage transmission systems that prevents reactive power from traversing large distances and requires that a regional reactive power balance is maintained, it can be said that controls on other areas the violated buses would be less effective and would not generally be used.

However, the impact area of a contingency cannot always be straightforwardly defined. Certain transmission faults can cause active power flows to loop through other areas of the network. QBs and other active power controls[75] can be effective towards a constraint even when located in a different area. The extent that active power controls of other areas can be used to manage "distant" constraints is limited by the capacity of the network in their vicinity. The area to which the impact of the contingency is limited, although finite, has to be defined in a way that captures these interactions. Approaches that use fixed rules or sensitivity thresholds could lead to not usable or less economic outcomes if interactions are ignored.

The concept of locality has been used to reduce the size and the complexity of SC-OPF models. When a linear model with sparse formulation of constraints is used, one approach is to include in the model only the rows (constraints) of the overloaded branches and the ones loaded above a threshold for each post-contingency configuration.

74 Relatively to their resistance.
75 The interactions are less of a concern when using generators (BMUs) only as active power controls.

References [131] and [132] propose a network compression method for the post-contingency states instead. For each contingency a limited impact area ("active region") is identified. Initially, only the network elements (buses and branches) that are the most effected by the contingency are included, based on the voltage or power flow deviation from their pre-contingency values. The active region is extended to include, first, the controls that could be effective toward the elements of the active region (either connected to buses currently in the active region or in other parts of the network) and, then, the network elements (buses and branches) not currently in the active region whose power flows or voltages can be impacted significantly by those controls.

The network elements in the active region are kept in their real identity while those in the other parts of the network are approximated by an equivalent network using the REI-DIMO reduction method[76] [133] . To be able to use the generators on the reduced part of the network as optimisation variables, these are also kept in their real identity – i.e. they are not lumped to a single generator on the equivalent network nodes. As the network conditions vary, the active region identification and the network reduction has to be applied "on the fly" for each considered contingency case as part of an iterative contingency selection process.

The method tries to comprehensively address all the shortcomings identified earlier in this section and its use could be necessary for very large power systems [134] where only a few contingencies can be practically included in the main SC-OPF model[77]. However, when there is an option to use the complete post-contingency model, it should be preferred.

4.1.2 Identifying the critical contingencies

Iterative methods rely on contingency filtering techniques to find candidate "critical" contingencies – those that are likely to produce active constraints at the SC-OPF optimal solution – to be included in the next iteration of the main SC-OPF problem. They generally make use of the following concepts.

'Classic' contingency analysis: solves a power flow that applies the 'N-1', 'N-2' or 'N-D' security criterion. The effect of automatic controls activation is captured in the power flow.

Contingency screening methods: screening methods aim to approximate the effect of a contingency without the computational expense of solving a complete the power flow. This is

76 Reference [188] provides an overview of alternative network reduction methods that could be used.
77 Using the AC model for equality and inequality constraints

an advantage in real time security applications (as in the control room Energy Management System for instance) especially at times when computational power is limited.

As the most computationally intensive part of a power flow calculation is the Jacobian[78] matrix factorisation, screening techniques precompute and store offline sensitivity factors, such as line outage distribution factors, or complete factorised matrices. They are used to calculate the incremental change on branch flows or in voltage angles and magnitudes that result from the contingency. Computation times are decreased at the expense of storage requirements. While the first option cannot adapt for sustained branch outages or other topological changes that took place after the calculation of the sensitivity factors, the precomputed factorised matrices can be adjusted for ad/hoc topological changes using partial re-factorisation techniques according to reference [135]

Bounding methods [136], take advantage of the fact that the impact of a contingency is generally limited in the areas of the network in its proximity, as explained in the previous section. For each contingency, they identify a subnetwork that contains only the elements that are impacted from the contingency. The solution of the subnetwork, although approximate, makes it possible to deduce if network elements outside the subnetwork are also affected, acting as a network constraint filtering. The subnetwork is expanded in the next bounding method iteration if that is the case. The method was further improved – [135], [137] – to use the pre-factored matrix technique.

Contingency analysis or screening methods can inform the user if a contingency is causing violation of the limits of any network element. On their own, they are not enough to conclude if a contingency is likely to belong to the ‘critical’ set of the SC-OPF problem. For that, one needs to quantify its impact and compare it with that of other contingencies

Severity index: Severity indexes try to define a common measure for the impact of each contingency. Contingencies that score higher on the index are the ones that need to be analysed further. In practice, different indices may need to used or for the different type of contingencies (branch outage or generator outage) and/or for each type consequence (branch MVA limit violation, bus voltage magnitude violation, voltage step change violation etc.) [138]. The consequences of a contingency can be measured or approximated with any of the power flow or screening methods described previously.

78 Or the B’, B’’ matrices of the fast decouple and DC power flow as applicable

Regarding branch flow outages and MW limits violation, the following index can be used [139]:

$$SI = \sum_{\text{over all branches } l} \left(\frac{P_l^{flow}}{P_l^{max}}\right)^{2n} \quad (4.1)$$

where n is a large number. SI will be a large number when on or more branches exceed their limit and a small number when they do not. However, ranking the constraints in terms of impact using indexes can be problematic. Using the example of (4. 1) it can be seen that contingencies that create a number of less severe, easily manageable, overloads could be ranked closely to the contingencies that cause viewer but more severe overloads.

Non-dominated or "umbrella" contingencies: a contingency is dominated if, at a given operating point, the constraint violations caused by any of the other contingencies are larger – similar to the "worst" contingency of a boundary analogy used earlier. It can be said that the solution of a SC-OPF model that includes non-dominated contingencies only would be the same or near identical to one that includes all 'credible' contingencies [140],[141]. Contingency filtering methods can then select only the non-dominated contingencies – instead of all that cause violations – to be added to the set of contingencies to be considered at the next SC-OPF iteration [142].

Reference [143] (Chapter 6) tries to follows a different approach to 'ex-ante' identify the critical contingencies using the pre-solving [144] capabilities of mathematical programming solvers. During pre-solving, certain types of infeasibility[79] can be detected and the size of the model passed on to the core optimiser module is reduced by removing redundant constraints amongst other things. Reference [143] is not able to make any practical use of this concept. One of the reasons identified is that pre-solving removes the redundant constraints from the model (leaving only the "convex hull" of the feasible region) but it does not make any attempt to find what would be the 'active' ones between them. Which of the "convex hull" constraints would become active in the model solution is dependent on the form and weighting of the objective function.

4.1.3 Decomposition methods

Decomposition methods take advantage of the structure of some optimisation problems where, fixing some of the variables temporarily makes the remaining problem more tractable, and separate them into one 'master' problem and a specific number of 'slave' sub-problems. The

79 Making use of the unboundedness property of duality theory: if the primal (dual) problem has a feasible and unbounded solution, then the dual (primal) problem is infeasible. Ref [113] – Chapter 4.

best known methods are the Dantzig-Wolfe and Benders decomposition [145]. The original Benders method was generalised for use in non-linear problems in [146]. The method iterates between the solution of the master problem – that provides the temporary solution – and that of the sub-problems – where each slave problem updates one "cutting plane" linear constraint of the master problem. That constraint is a function of the master problem's decision variables and it is a measure of the feasibility of the current – temporary – solution for the specific sub-problem. It provides a systematic way of constraining the feasibility region of the master problem

The breakthrough application of Benders method in power system security with corrective rescheduling is described in [7] – where Model 4-1 and Model 4-2 are provided in order to demonstrate the concept. The special structure[80] of the direct C-SCOPF model allows for its decomposition to: a) one master model (Model 4-1) that includes the base case (pre-contingency configuration) optimisation variables ($\mathbf{x}_0$), the base case constraints (4. 3) and cutting plane constraints that are provided/updated by the sub-problems (4. 4) and, b) one separate model for each contingency case that includes the optimisation variables and constraints only of the post-contingency configuration (Model 4-2).

As the objective of each of the sub-problems must provide a measure of its feasibility in the solution $\mathbf{x}_0^{j*}$ of the master problem at iteration j, the non-negative slack variables $\mathbf{r}_i$ and $\mathbf{s}_i$ are added to constraints (4. 6) and (4. 7). The objective of the sub-problem then becomes one of minimising the sum of slack variables (i.e. minimizing infeasibility, because if there are no constraint violations $w_i\left(\mathbf{x}_0^{j*}\right) = 0$). The Lagrange multipliers[81] are used as objective function coefficients for the corresponding slack variables and provide the link between the change of sub-problem infeasibility to the base case operating point (4. 5). The master problem retains the original SC-OPF objective (4. 2) and provides at each iteration the temporary optimal solution – $\mathbf{x}_0^{j*}$ – subject to ensuring feasibility of the base case constraints and minimising in-feasibility of the sub-problem constraints. It can be proven that, under convexity assumptions, the value of $w_i(\mathbf{x}_0)$ improves at successive iterations and the method converges at the global optimum.

80 In the C-SCOPF direct model, the parts of the model referring to the base case/pre-contingency configuration and that of the post-contingency configurations are usually coupled only with the constraints that limit the deviation of controls from their pre-contingency values. For a given set of pre-contingency control values, the post-contingency parts/models can be solved independently.
81 The shadow prices of each of the constraints (4. 6) and (4. 7).

$$\min \mathrm{c}(\mathbf{x}_0) \tag{4.2}$$

s.t.

$$\mathbf{A}_0(\mathbf{x}_0) \geq \mathbf{b}_0 \tag{4.3}$$

$$\mathrm{w}_\mathrm{i}(\mathbf{x}_0) \leq 0 \quad \text{for all i } = 1,2,\ldots, \mathrm{k} \tag{4.4}$$

Model 4-1: Master problem – [7]

$$\mathrm{w}_\mathrm{i}(\mathbf{x}_0) = \min\left(\mathbf{L}^{\mathrm{ri}} * \mathbf{r}_\mathrm{i} + \mathbf{L}^{\mathrm{si}} * \mathbf{s}_\mathrm{i}\right) \tag{4.5}$$

s.t.

$$\mathbf{A}_\mathrm{i}(\mathbf{x}_\mathrm{i}) + \mathbf{r}_\mathrm{i} \geq \mathbf{b}_\mathrm{i} \tag{4.6}$$

$$|\mathbf{x}_0 - \mathbf{x}_\mathrm{i}| + \mathbf{s}_\mathrm{i} \leq \boldsymbol{\delta}_\iota \tag{4.7}$$

Model 4-2: Sub-problem for the post-contingency configuration i [7]

Convergence cannot be guaranteed for non-convex problems such as the SC-OPF model that uses the AC power flow model. So, although the decomposition has been used for various applications over the years, care is recommended. According to [66], although Benders decomposition remains efficient for very large networks when good convergence of a specific application is achieved, very large scale practical testing is still required.

4.1.4 Current injection methods

Current injection methods [147] address the computational burden of having to calculate distribution factors (like the PTDFs and QBDFs) for every post-contingency configuration and/or after a switching operation. The method first calculates the factors for the base network (or pre-switching configuration) once. All the considered switching operations or contingency outages of branches are modelled as an "in and out" operation of branches (which may require adding artificial branches). The effect of an outage or switching operation is then replicated by considering "virtual" complex current injections at the buses at both ends of the branch (that cancel out the current of the faulted line) while keeping the network topology unchanged. The method can also be used to include switching operations as optimisation variables, model complex types of contingencies such as a bus section outage, or to model the effect of each step of a complex switching operation (such as a bus split) without having to run a power flow in each step [148]. Reference [149] improves the accuracy of the "virtual" injections by improving the way they are calculated.

4.1.5 Other simplifications

Reference [150] considers the use of DC SC-OPF within the context of an iterative AC SC-OPF framework for active power dispatch. The DC SC-OPF is used as a contingency filtering method that identifies candidate critical contingencies that are included in the AC P-SCOPF model in the next iteration. The paper also explores the use of a DC C-SCOPF mixed integer linear programming model, with constraints limiting the maximum number of corrective actions, for deciding corrective control actions that are then fed into in a subsequent AC C-SCOPF model – in addition to identifying corrective actions.

4.1.6 Discussion

This section presented a number of approaches for using optimisation models as part of an optimisation process (or framework) in practical application. Some aim to overcome practical limitations such as the growing size of the "direct" model or having to recalculate distribution factors for each contingency and others try to identify the contingencies that are likely to produce 'active' constraints at the optimal solution.

One important takeaway of this section is that optimisation models can be used as part of a "decomposed" framework/process where preventive and corrective actions are calculated by separate models. This allows the impact of trialled preventive actions to be analysed before subsequent corrective actions are decided for instance or to understand which additional contingencies may need to be considered for preventive actions in a step-by-step iterative approach. Other approaches, reductions or simplifications presented in section 4.1 are not currently applied in the following but can find use if the QB coordination framework is deployed at a larger scale in the future.

4.2 Requirements of a QB coordination framework

In the previous sections we outlined how SC-OPF methods have been used in power system applications either using a direct model or an iterative or decomposed process. In the following, we will focus on the requirements that a QB coordination framework, used for active power re-dispatch operations, must adhere to.

4.2.1 The need for coordination of active power controls' operation

Coordination between the available control methods

Table 3-1 lists the methods/controls for thermal constraint management that are directly considered in this work. They can be combined in different proportions to achieve the desired outcome from a system security perspective. Each outcome would be different in terms of economy or complexity of operation. Relying on power flow control devices to a greater extent to balance or redistribute flows is expected to limit the extent that generators have to be used for the same purpose, for instance. The coordination framework should take into account the interactions between the different types of methods (and the individual control devices) directly and provide an outcome that is line with the chosen objective(s).

Coordination across system areas

Power flow control devices can impact flows on distant areas of the network. Deciding on their settings by focusing on the requirements of one area only or considering each area in isolation can result in a sub-optimal solution. A set of preventive QB tap settings that are optimal for a given system boundary (i.e. they maximise the transmission transfer capacity through the boundary subject to contingencies of branches on or around the boundary) could provide a less optimal solution for others. Control settings need to be coordinated across all credible contingencies. Deciding on and applying active power control actions should be based on a system wide, supervisory view of the network conditions.

Alternative control paradigms could be ineffective or sub-optimal:

- Automatic control based on local measurements and fixed control laws – similar to how voltage regulating transformers[82] operate – could lead to unwanted interactions on other parts of the system as device controllers do not have visibility of the rest of the network. For the same reason, a QB on automatic control mode cannot determine when a contingency has happened and what short-term thermal rating could be used – which can result in restricting the flows more than necessary [8], [49]. Further, the effectiveness of a QB tap change towards the flows of the target circuit depends on network configuration at the time (switching arrangements and circuits on outage) making the application of a fixed control law not always valid.
- Event based control where pre-defined actions are triggered following specific contingencies – similar to how special protection schemes (intertrips [151], [152]) work – can also lead to sub-optimal solutions as the control devices are reserved for the specific events and are not used as flexibly as they could.

The need for coordination is more profound in the densely interconnected ("meshed") parts of the high-voltage transmission system. The alternative control paradigms can be implemented with greater confidence in the radial parts of the network or in areas where there are not many

82 More specifically, the "on load tap change" voltage regulating transformers that connect the transmission with the distribution networks.

alternative transmission routes and the power flows, for a wide range of operational conditions, can be predicted with greater certainty. There, the interactions can be studied and control laws or event based actions that are effective under a range of operating condition can be defined. Indeed, reference [153] [83] recommends that transmission automation schemes are used in the areas of the network where the impact of their operation can be easily understood and reference [151] states that (commercial) intertrips would be negotiated when the need arises on short/medium term ad-hoc basis[84]. Practical QB automated schemes are limited to special applications at lower voltages and/or radial distribution networks [154], [155].

Coordination between preventive and corrective operations

Power flow control settings need to be coordinated between preventive settings and corrective actions. The preventive settings chosen for a device determine the range of settings available for corrective actions. The preventive settings change the pre-fault power flows and can mitigate the consequences of multiple contingencies simultaneously while the corrective actions required differ by contingency. Further, what corrective actions are required is subject to the pre-fault operating point, as established after the preventive settings have been applied. Consequently, the framework should provide a method to coordinate and prioritise the use of devices/active power control methods in preventive and corrective operation so that the overall objective is met as well as possible.

Coordination across system borders and utilities

One last aspect of coordination is that between different utilities and TSO control areas. This is not a concern for the GB electricity system as the ESO has direct control over the active power control devices in all three TO areas. Further, GB is a single market area connected with controllable DC links to other systems.

In continental Europe where AC interconnected systems extend across national and/or market areas it has been observed that, subject to the market integration and the coordination between different TSOs, actual power flows may not always follow the contracted power exchanges. The "unwanted" flows can cause congestion on third party – not involved in the transaction – TSO areas. Active power control devices (PSTs) have been used to mitigate that. Their operation must be coordinated between the different TSO areas as they effect the flows on the

83 Reference [153] makes the above statement on the context of Active Network Management (ANM) schemes. It is included here as an example as most ANM schemes make use of the two control paradigms mentioned above.
84 Up to year ahead operational planning timescales

other systems and the TSOs may have different control/operational objectives. The topic is explored in more detail in section 3.5 and in Chapter 6 of reference [37]

4.2.2 How to decide on actions for the different operating states

At any given moment, the power system can be seen as being into one of the following states: Normal, Alert, Emergency and Restorative [6] [156] The Normal state (where no operational limits are exceeded) can be "Secure" or "Correctively Secure" [64] as seen in Figure 4-1. The system transitions through the states by events (credible or not credible contingencies) and by SO actions (manual, automatic or Emergency/Defence plans). Normal and Alert states can both be experienced in the day to day operation. In a Correctively Secure state, equipment is allowed to exceed its "continuous"[85] (long term) rating following a contingency. Corrective actions must be applied that will remove any overloading or ab-normal voltage conditions.

Constraint cost – the payments that SOs make to third parties to manage the limitations in network capacity and to operate the network according to the security standards (section 2.2.2) – has two components: the preventive payments (cost of preventive actions) that are definitely incurred, and the payments that will only be incurred if a contingency takes place [51]. The later part could be due to the payments for the corrective actions required immediately after the contingency – as described previously – or to transition the system from Alert back to the Normal state[86]. In any case, all components of cost will be added up to the overall constraint cost that will be recovered from the transmission Users through charges and eventually from the consumers.

85 In the GB transmission network, two 'continuous' ratings are specified for conductors, the "pre-fault continuous" and the "post-fault continuous". The former ensures that there is some margin for the conductors' temperature to increase after the contingency. In the following, the term 'continuous' refers to the "post-fault continuous" as it is the one that should be adhered to with respect to the secure system operation. More information about the application of conductor ratings is provided in references [8], [34] and in the following.

86 In both 'Normal' and 'Alert' states there are no operational limit violations. If following a contingency (and the actions required to remove the overloads or abnormal voltages) the system is no longer 'N-1' or 'N-D' secure (i.e. in the event of a second contingency) it is said to be at Alert state. Further generation re-dispatch is necessary to re-secure the network and transition back to 'Normal'.

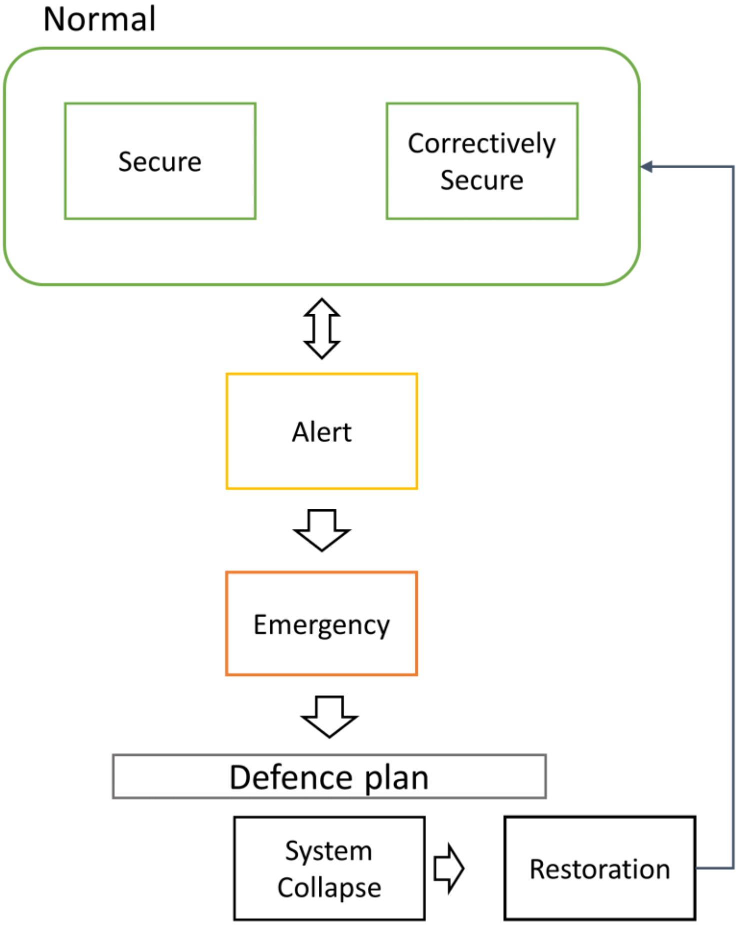

Figure 4-1: System states – adapted from [6].

The frequency and duration of transmission faults is an indication of how often and for how long the post-contingency/corrective component of constraint cost is expected to be incurred. References [157], [158] analyse contingency outage frequency and duration data from the three GB onshore TOs and correlate the faults observed with the prevailing ambient conditions. Reference [157] provides further insight about the geographic distribution of the faults and the duration equipment had to be on outage.

In a single year of operations, the GB transmission system is expected to experience a couple of hundreds single circuit transmission faults but only 2 to 6 double circuit ones [159][87]. Because the 'N-D' security criterion (double circuit faults are credible faults) was used in the

87 Reference [159] mentions that in 2016 the GB system experienced 2 double circuit faults and 4 busbar faults (that in certain cases also result in a double circuit outage depending on network configuration and substation busbar running arrangements).

design and expansion planning of the system in the previous decades, it is the less frequent double circuit faults that tend to have consequences and require actions in present day operation.

The sources mentioned support the notion that the preventive/pre-fault constraint cost component, that is definitely incurred, makes up the vast majority of the constraint cost over the course of operation and it is the component that should be driving constraint management decisions. The corrective/post-fault component will only need to be accounted for after a fault has actually happened.

This is true irrespective of the procurement method of the constraint management service – the balancing mechanism, forward trades, constraint management contracts or a commercial agreement for use of a special protection scheme [14] – or whether the network has to be re-secured to transition from the Alert to the Normal state or not.

It can be argued that since the two components of cost come with such a difference in probability of occurrence, they should not be combined in the same objective function of a direct C-SCOPF model. But more important than that, in principle, they are not comparable.

Any decision on preventive control actions/generation re-dispatch should not be affected[88] by the potential cost of corrective actions as the post-contingency states have not materialised at present time. If the C-SCOPF model includes zero, artificially low and/or equal objective function coefficient values for the decision variables of the post-contingency states in the model to mitigate that, it is not guaranteed that it will produce a usable set of corrective control actions[89].

From the above discussion, the overall objective that the QB coordination framework should meet can be broken into two components:

- During preventive/pre-fault operation: the objective should be solely to minimise the cost of preventive actions.
- During corrective/post-fault operation: the objective should be to produce an action plan for each contingency that includes corrective actions that, subject to the decided preventive actions, can ensure that the consequences of the fault can be mitigated. The actions should be fit for purpose and follow the established procedures and the (current

88 Through the objective function of the direct C-SCOPF model that combines preventive and corrective state variables in the same model

89 Some of these conditions will lead to a degenerate solution. There will be more than one optimal solutions and no driver for the optimiser to select a particular one.

or planned for) ability of the control systems and the power flow control methods used.

There are certain operating conditions when the framework objective described above should be adjusted. The first is when adverse weather conditions or other factors prevail that increase the risk normally associated with certain events beyond what is acceptable (outside Zone 4 in Figure 4-2). This can happen if, under the given conditions, the probability of certain events is higher than normal, there is reasonable concern that more than one events can occur in short succession – e.g. due to a common factor – and/or the consequences of any of the above is greater than a threshold. An example is when extreme weather conditions are experienced in large regions of the system. Other factors could be asset health conditions of specific branches.

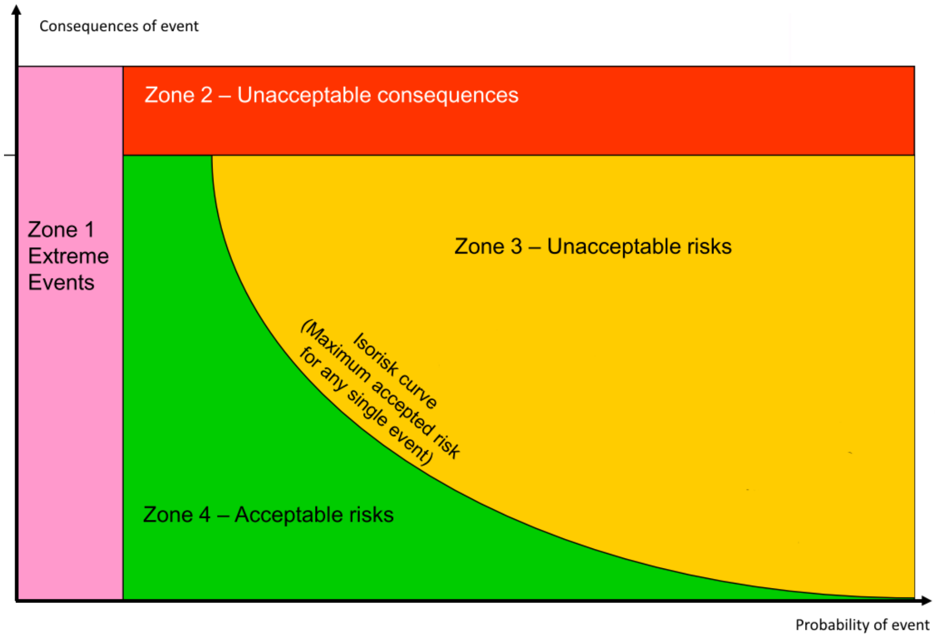

Figure 4-2: Probability, consequences and risk of any single event. When planning to operate using corrective actions one must ensure that the system stays within Zone 4 or it can be moved back to it sufficinetly quickly. Source: [6], [160].

The second occasion is when Users exercise market power and submit penalising[90] bids or offers that would have to be accepted in the case of certain events. Managing both these exceptions is beyond the scope of this work.

In conclusion, the QB framework must then also meet the following requirements:

- It must provide SO engineers with a minimum cost set of preventive actions to be applied during or at the start of the relevant dispatch period. It must also provide an action plan for each of the credible contingencies that require corrective actions.
- Further, it should separate the list of credible contingencies into those that a) are secured through the preventive actions only and/or require no further actions, b) require corrective action. For the latter, it must be able to identify the flow limit that the contingencies need to be secured against with preventive actions only – i.e. the limit the overloaded circuits right after the contingency should not exceed.

4.3 Framework for coordination of QB tap settings

4.3.1 Framework overview and rationale

The framework consists of two stages (Stage A and B) and makes use of two OPF models (a post-contingency OPF and a preventive SC-OPF). The first stage (Stage A) is always applied to every considered dispatch period (market determined generation and demand dispatch). The second (Stage B) only needs to be applied to the dispatch periods that preventive use of active power controls is also necessary to secure the network against branch contingencies as explained in the remainder of this section and in section 4.3.2. In the following, "contingency" refers to a branch contingency. It could be an 'N-1' or 'N-D' event as was explained in section 2.2.1.

Framework stages

Stage A: Aims to identify if, in the particular dispatch period, all branch contingencies can be secured with corrective actions only. This means that, for every branch contingency case that would cause a branch to overload, Stage A tries to establish if corrective actions that would alleviate the overload (reduce the flow of the overloaded branches below their continuous rating) can be applied. The OPF problem used for that purpose is called in the following Post-Contingency OPF. One Post-Contingency OPF must be solved for each contingency case (i.e. it is a single state OPF model).

90 Note that nuclear reactors can submit artificially high Bids to indicate that they are not physically able to change their output quickly enough to be used for post-fault constraint management - also indicated by the Balancing Mechanism "Dynamic data" (ramp rates) [15]. This is not the case discussed here.

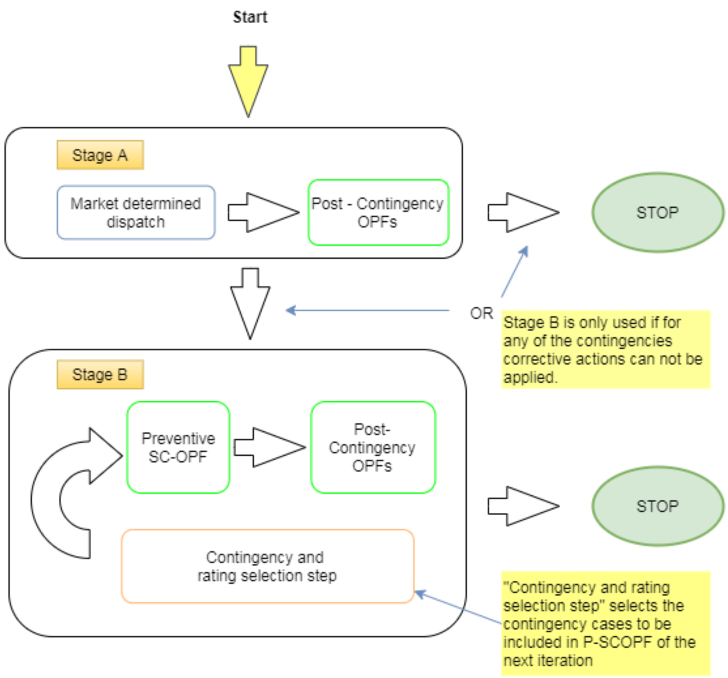

Figure 4-3: Overview of the QB coordination framework stages and how they interact

Stage A is not iterative – its steps (steps A1 to A6 in Figure 4-7) need only be applied once. Since only Post-Contingency OPFs are used, Stage A does not change the market determined generation dispatch (initial operating point). If all contingency cases of the dispatch period can be secured with corrective actions only the framework stops. The optimal corrective actions (solutions of Post-Contingency OPFs) become the blueprint for the plan of actions that the SO engineers provide to the control room to be applied in the event of each contingency. If all the contingencies of the dispatch period can be secured with corrective actions only no preventive generation re-dispatch cost is incurred.

If not all of the contingencies can be secured with corrective actions only at the initial operating point (i.e. there exist one or more cases where corrective actions cannot be applied[91]), preventive use of active power controls is also necessary and Stage B must be used. Note that in this case all the calculated corrective action plans of Stage A must be discarded[92].

Stage B: Aims to provide the minimum cost set of preventive actions and plans of corrective actions for those dispatch periods where one or more of the contingencies cannot be secured with corrective actions only – i.e. stage A is not sufficient. It makes use of two OPF models:

91 In practice this means that the overload(s) caused by the contingency is too high (exceed the short-term rating of the branch) or the overload(s) caused by the contingency is within the short term rating of the branch but the Post-Contingency OPF cannot return a solution (infeasible). This is explained in more detail in the next section 4.3.2 .

92 This is necessary as Stage B includes a preventive SC-OPF that will change the initial network operating point that the corrective actions of Stage A were calculated from (incremental actions).

a preventive security constrained OPF (called P-SCOPF in the following) and the Post-Contingency OPF introduced previously. Stage B is iterative so all of its steps (B3 to B10 in Figure 4-8) must be repeated until all contingency cases are secured. Once completed, Stage B can provide the blueprint for the set of preventive actions (to be applied at the beginning of the dispatch period) and for the plans of corrective actions (to be applied in the event of each contingency) that the SO engineers submit to the control room. The P-SCOPF will change the network operating point. If BMU or interconnector preventive actions are necessary in the optimal P-SCOPF solution, then preventive generation re-dispatch cost will be incurred.

Stage B aims to secure as many contingency cases as possible with corrective actions only in a similar manner as Stage A. These contingency cases are not included in the P-SCOPF and plans of corrective actions are calculated through the Post-Contingency OPFs as before. This is not going to be possible for all the contingency cases or the framework would have stopped at Stage A.

If corrective actions cannot be applied for a contingency case (at the market determined operating point), Stage B tries to secure it with a combination of corrective and preventive actions first (as opposed to with preventive actions only). In this context, preventive actions are only used to the extent necessary to enable post-fault, corrective operation (as section 4.3.2 explains in more detail). In practice, this is achieved by using the 'short-term'[93] thermal rating – in $\mathbf{l}_{\max}^{k}$ of (3.25) – for the overloaded branches of the contingency in the P-SCOPF (Table 4-7).

Using the short-term rating in the P-SCOPF means that, having applied the preventive actions, the post-fault loading of the respective branches could be above the continuous rating in the event of the contingency but it will be less or equal to the short-term rating used. So corrective actions can now be potentially applied and the Post-Contingency OPF can be used to calculate the optimal set of corrective actions.

If a contingency case cannot be secured with corrective actions only (not included in the P-SCOPF) or with a combinations of corrective and preventive actions (included in the P-SCOPF at the short-term rating), Stage B resorts to securing it fully with preventive actions. This is achieved by using the 'continuous' thermal rating – in $\mathbf{l}_{\max}^{k}$ of (3.25) – for the overloaded branches of the contingency in the P-SCOPF (Table 4-7). Using the continuous rating in the P-SCOPF means that, having applied the preventive actions, the post-fault loading of the

93 A 'short-term' thermal branch rating is a rating that can be applied for a short (pre-defined) period of time. It is higher than the 'continuous' rating that can be endured in the long term (see sections 2.2.5 and 4.3.2). For corrective actions to be applied, post-fault overloads must not exceed the short-term rating.

respective branches will be less or equal to the continuous rating and no corrective actions are required.

The selection of contingency cases to be included in the P-SCOPF and the rating used for the overloaded branches of each (i.e. short-term or continuous) takes place at the **"contingency and rating selection step"** (B10 in Figure 4-8). The step uses information from the current Stage B iteration (i.e. which cases were included in the P-SCOPF, the results of contingency analysis, of the short-term rating assignment and of the solutions of the Post-Contingency OPFs that precede it) to select the contingencies that will be included in the P-SCOPF of the next Stage B iteration[94] and the ratings used for the overloaded branches of each one.

Framework OPF models

The following tables provide an overview of the two OPF models used in the framework.

Table 4-1: Post-Contingency OPF model overview

Post-Contingency OPF	
Purpose	To provide a plan corrective actions to be applied in the event of a single contingency (single network state OPF)
Decision variables	QBs, BMUs, Interconnectors, W-HVDC
Branch flow constraints	Continuous rating for all branches of contingency case
Additional constraints	Limit on the volume of post-fault generation re-dispatch Limit on the number of Bids acceptances (strategy parameter[95]) Limit on the number of Offer acceptances (strategy parameter) Limit on the number of QB devices or pairs used (strategy parameter)
Model	Model 3-3 where: • equation (3.15) is replaced by equations (3.36) to (3.39) • equation (3.29) is added

94 Every stage B iteration (P-SCOPF model) starts from the market determined/initial operating point. Every P-SCOPF optimal solution is a new temporary network operating point to be trialled. The new operating point is determined by which contingency cases are included in the P-SCOPF (and the rating used for their overloaded branches).
95 A strategy is a set of settings regarding the use of active power controls that will be introduced in section 5.2

Table 4-2: P-SCOPF model overview

P-SCOPF	
Purpose	To provide a set of preventive actions to be applied at the beginning of the dispatch period (preventive security constrained OPF)
Decision variables	QBs, BMUs, Interconnectors, W-HVDC[96]
Branch flow constraints	Short term rating for cases secured with a combination of corrective and preventive actions Continuous rating for cases secured fully with preventive actions
Additional constraints	None
Model	Model 3-6

Rationale

SO engineers make use the ability of the system to withstand the consequences of a contingency for a short (pre-defined) period of time (in more detail in section 4.3.2). They aim to reduce, to the extent possible, the change of the market determined operating point (generator dispatch and network flows) that would be required to secure the system against the contingency otherwise. As discussed in section 4.2.2, the consumer is always exposed to the cost of the preventive actions (preventive generation and interconnector re-dispatch) in the day-to-day operation as it will be definitely incurred.

For that purpose, the QB coordination framework uses corrective actions to secure a contingency case by default. Preventive actions are only used when corrective actions cannot be applied for a specific contingency. When a contingency case cannot be fully secured with corrective actions only, an effort is made to secure it with a combination of corrective and preventive actions before reverting to securing it with fully with preventive actions only. In this context, preventive actions are only used to the extent necessary so that corrective actions can become applicable again i.e. they are used to enable corrective operation.

Securing a contingency with a combination of corrective and preventive actions is made possible by using the short-term ratings for the overloaded branches of the contingency in the P-SCOPF. Using the less restrictive short-term rating is expected to generally result to a lower volume of preventive generation re-dispatch and less of a change in the pre-fault network flows. The framework aims to secure the network by including only the necessary contingency cases in the P-SCOPF and using as high a rating as possible for their overloaded branches.

96 “Penalty” variables are also used in the P-SCOPF model to that model the need for day ahead ‘strategic’ actions such as starting up off merit plants that are not currently available (see section 4.3.4).

4.3.2 Operating with corrective security

Corrective security takes into account the ability of the system to withstand the consequences of a contingency outage for a short pre-defined period of time and that of the system operator to apply appropriate corrective actions that remove the consequences. Actions take place only after the contingency has happened and must be completed before that time elapses.

The system's ability is described with the short-term thermal ratings of the equipment. A short-term rating is higher than the 'continuous' rating – that can be endured for the long term – as the equipment is designed to be able to sustain it only for a short pre-defined period of time. When short-term ratings are used in planning and operation, they provide an additional headroom for managing the capacity of existing assets that can result in more efficient and economic operation.

The exact short-term rating value that applies in a given situation is a function of the pre-fault flow of the branch and of the endured time. The higher the pre-fault flow the lower the short-term rating that can be applied for a given period of time. Alternatively, for a shorter time period a higher short-term rating can be sustained. SOs define a number of pre-set time periods (i.e. 3 minutes, 10 minutes, 20 minutes after the fault) for the application of corrective actions that each comes with a set of short-term ratings. The volume and type of corrective actions that can be used in each time period vary (Table 4-3). The 3-minute time period only includes controls that operate automatically as a response to the contingency (special protection schemes) or the change in network parameters that resulted from it (voltage regulating transformers and automatic capacitor switching). In practice the impact of the operation of these controls on the post-fault network flows and voltages has to be considered (through contingency analysis) in operational planning when deciding for the manual corrective actions that follow. The manual corrective actions must be able to remove any consequences of the fault that remain after the application of these controls. In the GB transmission system QB taping is considered in the 20-minute time period [34] [8].

Table 4-3: Definition of time periods and available corrective action. Source: adapted from [8]

End of time period (minutes after fault)	**Description**	**Control actions**
3 minutes	Intermediate-term voltage performance/Automatic actions phase	End of automatic voltage regulating transformer tapping and capacitor switching. Special protection schemes.
20 minutes	Long-term voltage performance/Manual actions phase	Manual switching of reactive compensation plant. BMU Bid and Offer acceptances. QB tapping.
Sustained		Manual network reconfiguration

Figure 4-4 summarises the short-term rating factors used in the results presented in Chapter 5 (section 5.3). It is assumed that the time period that applies is 20 minutes. It can be seen how the short-term rating value that can be used decreases as the pre-fault loading increases.

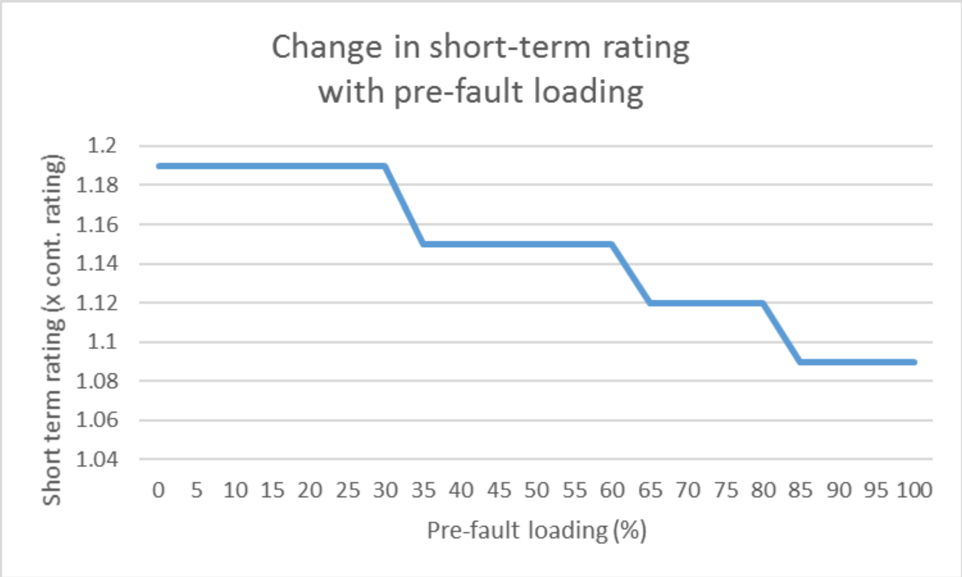

Figure 4-4: Decrease in short-term rating with increase of pre-fault loading[97]

Following the fault and the operation of automatic controls (such as voltage regulating transformers or special protection schemes – see 3-minute time period in Table 4-3) [8], SO

97 Note the short-term rating factors in Figure 4-4 are an assumption for the purposes of the study setup and do not correspond to any actual branch of the GB network.

engineers must take appropriate actions to reduce the flow of all overloaded circuits back to a level that is equal or lower to than the continuous rating. Control actions should not create any additional overloads or limit excursions. The types of controls that can be used and the rules governing their operation depend on a number of factors including the communication and control systems available[98], the speed and effectiveness but also on the 'acceptable' level of risk. All factors are considered in the security standards of each utility and encoded in the rules and procedures that SO engineers follow.

Using more controls or allowing certain controls to move more increases the complexity of operating the system when it is already at a vulnerable post-contingency configuration and makes the system post-fault state more vulnerable to information or control actuation errors. On the other hand, it is expected to allow more contingency cases to be secured to with corrective actions or with a combination of preventive and corrective actions that features less preventive generation re-dispatch than what would be otherwise required.

Consequently, the following criteria must apply when planning to operate the system with the corrective security paradigm for managing thermal constraints. For a given operating point and contingency case:

1. The flow immediately after the contingency outage, but following the activation of fast automatic controls, must be below the applicable short-term rating for all the overloaded circuits.
2. Corrective control actions must be available and effective in reducing the post-fault flow of the overloaded circuits below the continuous rating within the prescribed time. Following the actions, the flow of all network circuits must be below the continuous rating.

This process is described graphically in Figure 4-5 where the flow on a single transmission circuit used as an example. Note that despite the increase in flow due to the contingency, it never exceeds the short-term rating.

98 Control systems are used for control actuation and monitoring as well as monitoring the state of the system

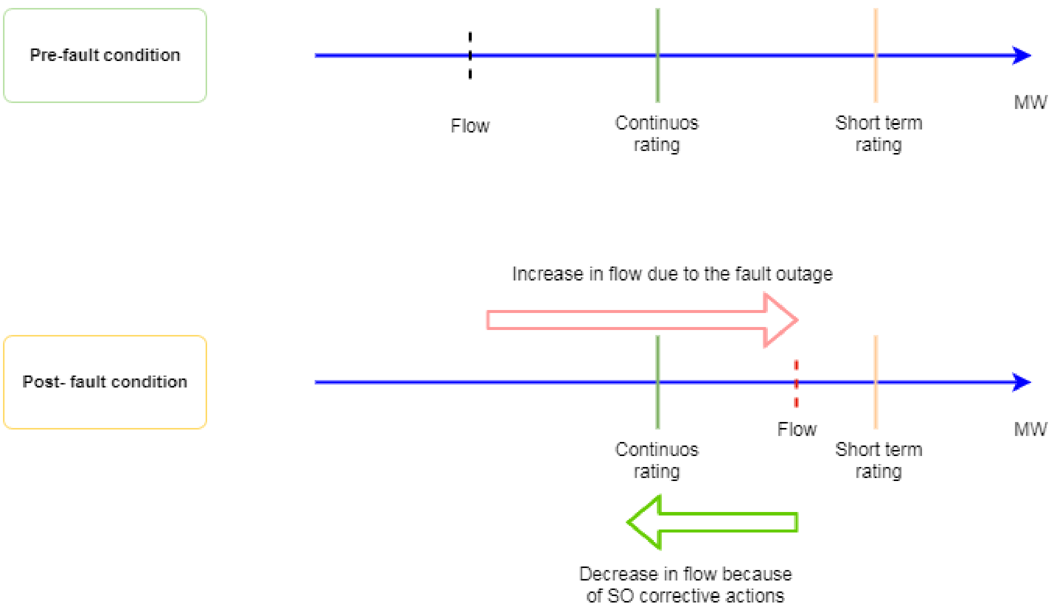

Figure 4-5: Operating with corrective security when the short-term rating is not exceeded

In the case of Figure 4-5, a single state (single network configuration) OPF method (Model 3-3) can be used to validate the second criterion, the availability of appropriate controls actions for a specific contingency case. The model should include the sensitivity factors that match the studied post-contingency configuration and it must use the continuous rating of branches in the $\mathbf{l}_{\max}$ vector - equation (3. 12). That way, after the application of the corrective actions all branches would be at or below their continuous rating. As discussed in section 3.4, the model can be used to enforce SO rules about the type of controls that can be used, the number of devices of each type, the overall number of control actions and the volume of actions that are possible within the short-term rating timeframe. We refer to that model as Post-Contingency OPF in the following.

If any of the Criteria 1 and 2 above cannot be met, the particular contingency case cannot be secured with corrective actions only. Figure 4-6 (A) provides a graphical example of that where the power flow increase because of the contingency exceeds the short-term rating of the line (Criterion 1 is not met for the particular operating point). Preventive actions are then necessary to reduce the pre-fault flow of the line to such an extent that the corrective actions are effective again – Figure 4-6 (B). Preventive actions can include (any combination of) generation re-dispatch and of use of QBs or other power flow control devices (Table 3-1).

In the case of Figure 4-6 (B), a preventive SC-OPF (Model 3-6) can be used to find the most economic preventive actions. The model must include the constraints (branches) of the base case – equation (3. 24) – and those of the contingency case – equation (3. 25). The overloaded branch of the contingency case can be "secured" to the short-term rating as in Figure 4-6 (B) so enforcing Criterion 1. The preventive actions will change the network "operating point" so the pre-fault flows across a number of circuits will be different. The validity of Criteria 1 and 2 must be reconfirmed.

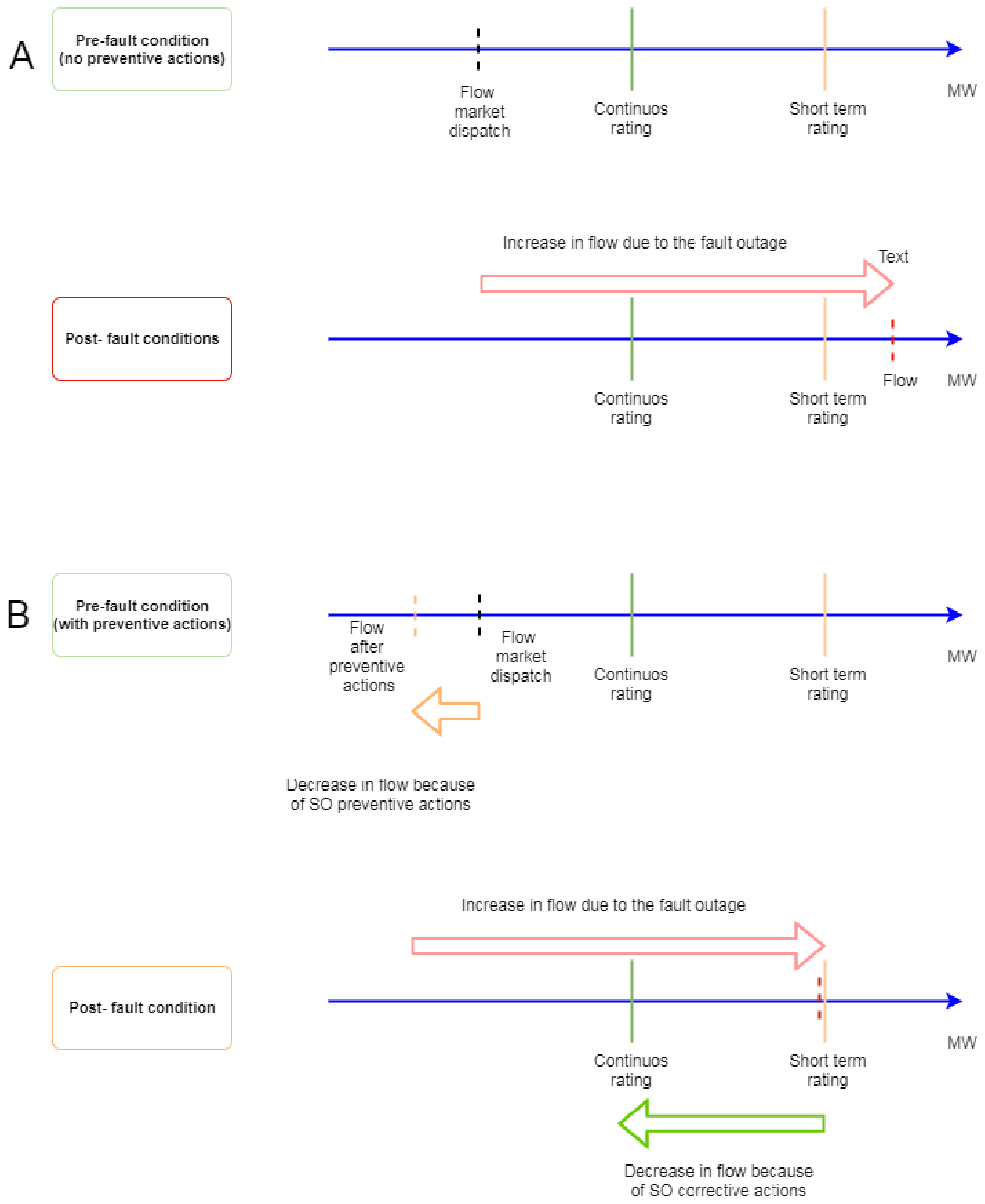

Figure 4-6: Operating with corrective security when the short-term rating is exceeded

4.3.3 Stage A – Dispatch periods that can be secured with corrective actions only

Stage A aims to identify if, for the specific dispatch period, all branch contingencies can be secured with corrective actions only and, if that is the case, to provide the blueprint of the corrective action plan for each contingency. A step-by-step description of Stage A can be found in (Figure 4-7 and Table 4-4).

Stage A tests if Criteria 1 and 2 for operating with corrective security (of section 4.3.2) apply for each contingency at the market determined dispatch (initial operating point). In practice this means that all post-fault overloads must be within the applicable short-term ratings and a set of corrective actions can be found (that respects the restrictions regarding the post-fault use of active power controls) that are able to reduce the post-fault loading to be less or equal to the continuous rating in the event of the contingency.

Stage A makes use of a single state OPF model (Post-Contingency OPF – Table 4-1). The OPF optimal solution provides the corrective action plan for that contingency. If the Post-Contingency OPF cannot provide a solution (i.e. the model is infeasible[99]) then preventive actions need to be considered for that contingency

99 The reason for infeasibility in this case is that there is insufficient ability to reschedule the post-fault flows within the limitations of how the controls are used for corrective actions. This can be captured in the pre-solving phase of the mathematical programming solver before the main solver routine is entered.

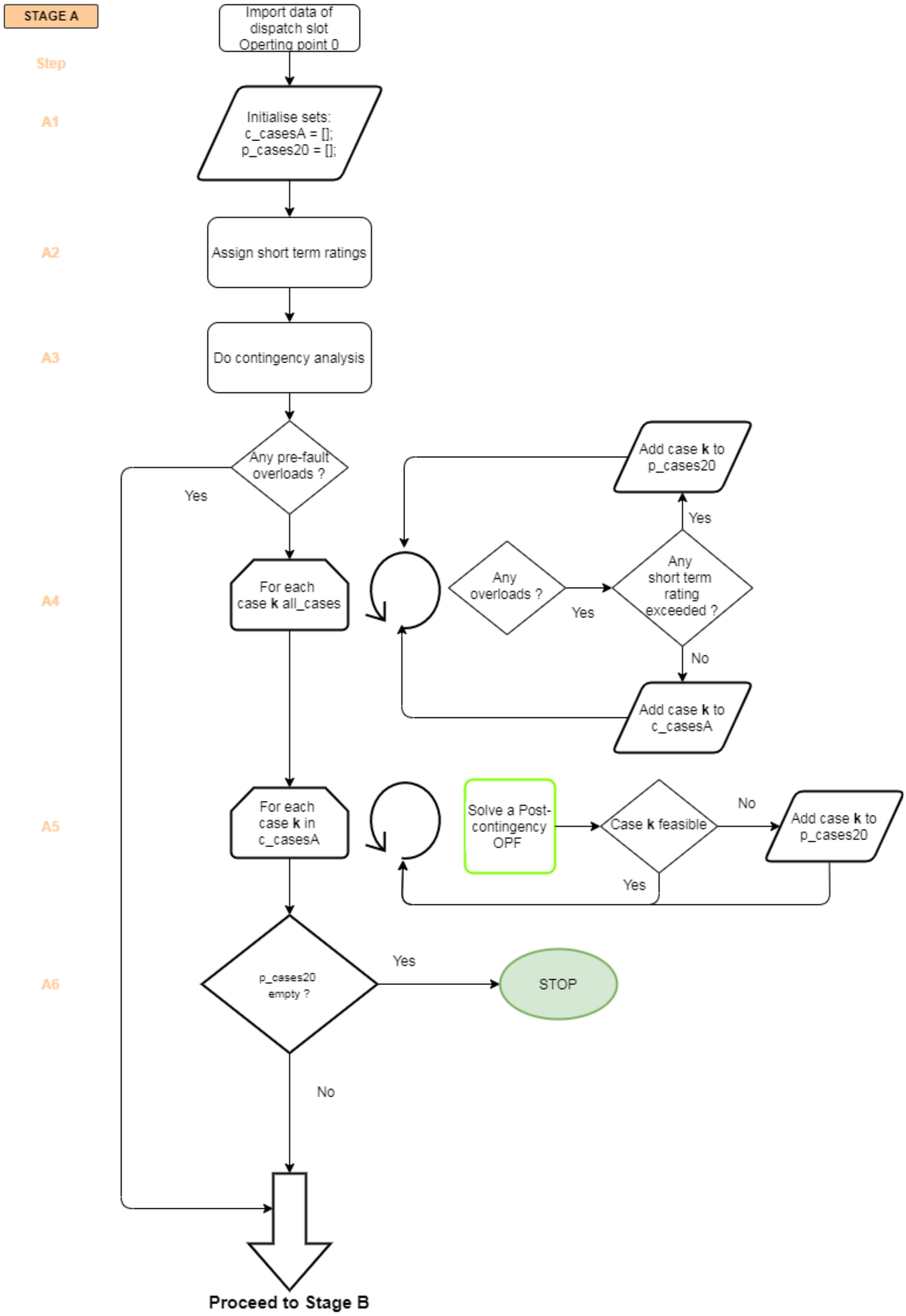

Figure 4-7: Stage A tests if all contingency cases can be secured with corrective actions only

Table 4-4: Step-by-step description of Stage A

Step	Description
A1	The following sets are initialised to empty. c_casesA p_cases20 Sets contain contingency case IDs and are used to exchange information between the different steps of the framework.
A2	The 20-minute short-term rating that applies (a function of pre-fault loading at the market determined operating point) is assigned to each branch.
A3	For each contingency: A contingency analysis calculates the post-fault loadings of the branches.
A4	For each contingency: The post-fault loading of each branch is compared to its short-term rating. Contingency cases (that produce overloads) are separated in to two sets: • p_cases20 that contain cases where the post-fault loading of one or more branches exceed their short-term rating. Corrective actions do not apply. • c_casesA that contain cases where the post-fault loading of all branches is below the short-term rating. Corrective actions may apply (would be determined in the next step)
A5	For each contingency in c_casesA: Solves a Post-Contingency OPF The OPF solution provides a plan of corrective actions for the contingency. An infeasible OPF means that corrective actions do not apply for the contingency and the ID of the contingency cases is added to the p_cases20
A6	If p_cases20 is empty (i.e. all contingency cases can be secured with corrective actions only) then stop. • The solutions of the Post-Contingency OPFs become the blueprint for the plan of corrective actions to be applied in the event of each contingency. If p_cases20 is not empty (i.e. one or more contingency cases exist where corrective actions do not apply) Stage B must be initiated. • The calculated corrective action plans (of step A5) are discarded. • The set p_cases20 is passed on to Stage B. • The short-term rating assignment (of step A2) is passed on to Stage B

4.3.4 Stage B – Dispatch periods that also require preventive actions

Stage B aims to provide the minimum cost set of preventive actions and plans of corrective actions for those dispatch periods where one or more of the contingencies cannot be secured with corrective actions only – i.e. Stage A is not sufficient. A step-by-step description of Stage B can be found in (Figure 4-8 and Table 4-7)

Stage B iterates through the following steps (B3 to B10 in Figure 4-8):

1. The solution of a preventive SC-OPF (Step B3 – Table 4-2) that calculates minimum cost preventive actions and “updates” the initial (market determined) operating point (operating point 0 in Figure 4-8).
2. Steps B5 to B8 that examine if, at the updated operating point (operating point J in Figure 4-8) Criteria 1 and 2 (of section 4.3.2) are met so that, subject to applying the preventive actions, all contingency cases can now be secured with corrective actions (as in Figure 4-6/B).
3. A contingency and ratings selection step that decides which contingency cases to include in the P-SCOPF in the next Stage B iteration and what rating to use for the overloaded branches of each (Step B10 – section 4.3.5).

Note that every Stage B iteration (P-SCOPF model) starts from the market determined/initial operating point. Every P-SCOPF optimal solution is a new temporary network operating point to be trialled. The new operating point will be determined by the contingency cases that are included in the P-SCOPF and the rating used for their overloaded branches.

As the operating point changes through the solution of the P-SCOPF model at each iteration, so does the pre-fault loading of the overloaded branches and the short-term rating that applies. This can invalidate the ‘default’ short-term rating (the one corresponding to the initial operating point) that was initially used in the P-SCOPF. This means that, although the post-fault overload would be lower than the ‘default’ short-term rating (that was used in the P-SCOPF) it could be higher than the short-term rating that corresponds to the new temporary operating point (J).

This is because the short-term rating that applies decreases as the pre-fault loading increases above a threshold (note the pre-fault loading thresholds and the short-term rating coefficients in Figure 4-4). In essence, for a given set of ambient conditions, a particular loading in respect of power flow determines the pre-fault operating temperature of the asset and, hence, the margin for an increase in that temperature following a system fault and the limit to the post-fault loading if the critical operating temperature is not to be exceeded within a given period of time post-fault.

To deal with this, a ‘reduced’ short-term rating must be introduced (Table 4-5). The ‘reduced’ short-term rating is the one that corresponds to the operating point J (instead of the initial operating point). The ‘reduced’ short-term rating is more restrictive than the ‘default’ short-term rating (and likely to require more preventive generation re-dispatch) but it is still higher than the continuous rating.

So Stage B tries to use the ‘reduced’ short-term rating in the P-SCOPF for the overloaded branches of the contingency cases where the ‘default’ short-term rating is not sufficient (instead of the more restrictive continuous rating). If the ‘reduced’ short-term rating proves to be also not sufficient, then the case will be secured fully with preventive actions in the next iteration (the continuous rating will be used in the P-SCOPF).

Table 4-5: Definition of ‘default’ and ‘reduced’ short-term ratings

Rating	Derived from	Assigned at
‘Default’ short-term	Operating Point 0 (market dispatch)	Stage A / Step A2
‘Reduced’ short-term	Operating Point J (new temporary operating point of iteration J)	Stage B / Step B6

At any given iteration, a contingency case could be in exactly one of the states shown on Table 4-6. The “move” of a contingency case from one state to the next takes place at successive iterations at the contingency and rating selection step (step B10 – section 4.3.5) by adding/moving the case to respective set.

Table 4-6: The possible ways a contingency can be secured with in the QB coordination framework

State	Implications	Stage B set
Not included in the P-SCOPF	Not secured with preventive actions. Corrective actions may be required	n/a
Included[100] in the P-SCOPF at the ‘default’ short-term rating	Secured with a combination of corrective and preventive actions	p_cases20
Included in the P-SCOPF at the ‘reduced’ short-term rating	Secured with a combination of corrective and preventive actions	p_cases20_red
Included in the P-SCOPF at the continuous rating	Secured fully with preventive actions	p_cases100

Stage B exits if the P-SCOPF cannot provide a solution (Step *B4*). This indicates that the control methods currently available to the OPF (Table 3-1) or the ability of the individual controls available in that dispatch period is insufficient. To ensure that the dispatch period is

100 The short-term rating will be used for the overloaded branches of the contingency and the continuous one for the non-overloaded ones as explained in the step-by-step description. It is omitted in this table for brevity.

secured, additional or alternative control options should be made available. Procuring them is a "strategic" decision as it needs to take place ahead of time so that they are available in the shorter term or during operation [105].

The strategic options to be considered depend on the context and timeframe that the framework is applied to. In operational planning for instance, one option could be to start up out of merit thermal plants[101] or to procure a service for generation reduction beyond that available in the Balancing Mechanism. In long term planning, options could include investment in additional transmission capacity.

The P-SCOPF can indicate the need for strategic options and quantify their impact using 'penalty' variables (see Appendix E: Study setup). They are active power injections (positive or negative) priced with artificially high objective function coefficients and they are only used by the P-SCOPF to avoid infeasibility. The location and volume of penalty variables activated can be analysed to determine what strategic options are required.

Finally, note that if the market dispatch of the specific operating period results in pre-fault overloads, Stage A of the framework is bypassed (Figure 4-7). The P-SCOPF of the first iteration of Stage B is then a single state OPF – it includes the 'Base' case network configuration and branch flow constraints only.

101 Starting up thermal plants not scheduled to run may be required when there is not enough thermal generation synchronised to balance the system following the acceptance of Bids. This could happen at mid/low demand and high wind dispatch conditions for instance.

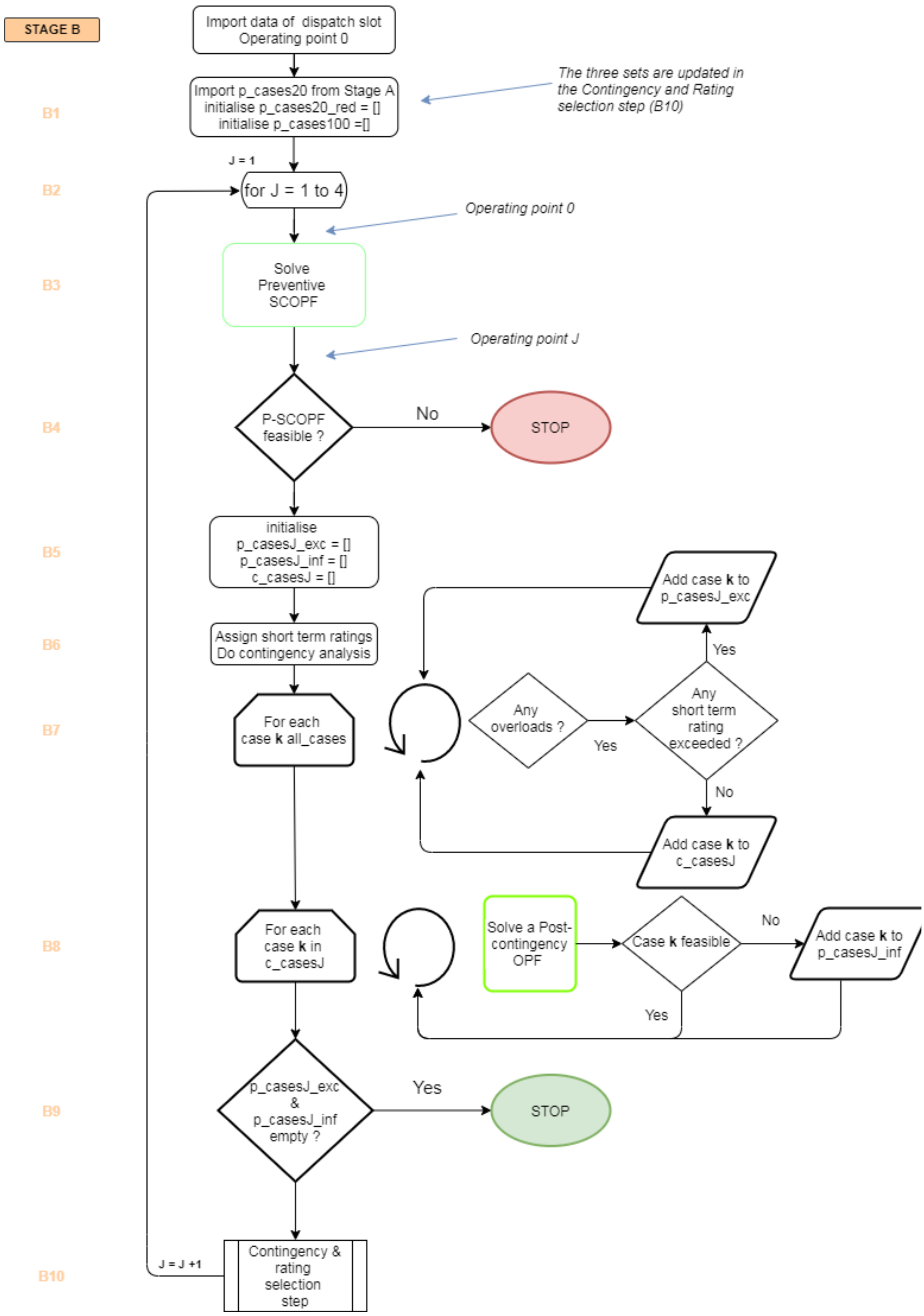

Figure 4-8: Stage B is used when not all contingency cases can be secured with corrective actions only

Table 4-7: Step-by-step description of Stage B

Step	Description
B1	At the start of Stage B: • Set p_cases20 is carried over from Stage A • Set p_cases20_red is initialised to empty • Set p_cases100 is initialised to empty The scope of the three sets extents throughout Stage B. Contingency cases enter or are moved across the sets in the *contingency and rating selection* step (B10) at the end of every iteration – so in practice the latter two will remain empty during the first iteration. Each contingency case can belong to one of these sets only. Sets contain contingency case IDs and are used to exchange information between the different steps of the framework.
B2	Steps B3 to B10 are repeated up to four times (iteration J: from 1 to 4)
B3	The P-SCOPF problem is formed and solved. It includes branch flow constraints of the contingency cases included in p_cases20, p_cases20_red, and p_cases_100 only. The overloaded branches of each contingency case are secured to the following ratings: • The 'default' short-term rating for cases in p_cases20[102] • The 'reduced' short-term rating for cases in p_cases20_red[103] • The continuous rating for cases in p_cases100 The non-overloaded branches of each contingency case are secured to the continuous rating. The starting point of the P-SCOPF problem is always the market determined dispatch (operating point 0). The output of the P-SCOPF is a new temporary operating point (operating point J[104]). The P-SCOPF solution provides the candidate set of preventive actions to be applied at the beginning of the dispatch period.
B4	In case of an infeasible P-SCOPF the framework exits.
B5	The following sets are initialised to empty: p_casesJ_exc p_casesJ_inf c_casesJ The scope of these three sets cover steps B6 to B10 only. The assignment of contingency cases in them (at steps B6, B7, B8) is relevant to the operating point J.
B6	At the new temporary operating point J do:

102 Since the starting point of every P-SCOPF is the market determined dispatch the short-term rating is the one that corresponds to the pre-fault loading of the market operating dispatch (operating point 0)
103 The 'reduced' short-term rating is the one that corresponds to the pre-fault loading of the operating point J-1 (of the previous framework) iteration, so it only takes effect from the second iteration.
104 The operating point J is determined by the contingency cases included in the P-SCOPF and the rating (short-term, 'reduced' short-term or continuous) used for the overloaded branches of each one.

	• Assign the 20-minute short-term rating that applies (a function of pre-fault loading at the operating point J) to each branch • Contingency analysis for all considered branch contingencies.
B7	For each contingency: it compares the post-fault loading with the short-term rating (as assigned at step B6). Contingency cases that produce overloads are separated in to two sets: • p_casesJ_exc that contain cases where the post-fault loading of one or more branches exceed their short-term rating. Corrective actions do not apply. • c_casesJ that contain cases where the post-fault loading of all branches is below the short-term rating. Corrective actions may apply (to be determined in the next step) Step B7 is the equivalent to step A4 for operating point J.
B8	Solves a Post-Contingency OPF for each contingency of c_casesJ. The OPF solution provides a plan of corrective actions for the contingency. An infeasible OPF means that corrective actions do not apply for the contingency and the ID of the contingency case is added to the p_casesJ_inf Step B8 is the equivalent of A5 for operating point J.
B9	If both p_casesJ_exc and p_casesJ_inf are empty, then stop. • At the updated operating point corrective actions apply to all contingencies that produce overloads • All the contingencies of the dispatch period can be secured with the established preventive and corrective actions Framework output ○ The solution of the P-SCOPF becomes the blueprint of the set of preventive actions to be applied at the beginning of the dispatch period. ○ The solutions of the Post-Contingency OPFs become the blueprint for the plan of corrective actions to be applied in the event of each contingency. If any of the sets p_casesJ_exc and p_casesJ_inf is not empty • At the new temporary operating point corrective actions do not apply to all contingencies that produce overloads • Continue to step B10 and to the next Stage B iteration
B10	The contingency and rating selection step selects the cases that will be included in the P-SCOPF of the next iteration (step B3) and the rating the overloaded branches of each case should be secured against. Its output is an update of sets p_cases20, p_cases20_red and p_cases100 – see section 4.3.5 Go to Step B3.

4.3.5 Contingency and rating selection step

The "contingency and rating selection step" is one of the steps of Stage B (Step B10) and it takes place once in every Stage B iteration (a Stage B iteration goes through steps B3 to B10). A step-by-step description can be found in (Figure 4-9 and Table 4-8)

The step uses information from the current Stage B iteration (i.e. which cases were included in the P-SCOPF, the results of the contingency analysis, of the short-term rating assignment and of the solutions of the Post-Contingency OPFs that precede it) to select the contingencies that will be included in the P-SCOPF of the next Stage B iteration and the rating that will be used for the overloaded branches of each ('default' short-term, 'reduced' short-term or continuous thermal rating).

The input to this step is: the three main sets (p_cases20, p_cases20_red and p_cases100) that, together, include the all the contingency cases that were included in the P-SCOPF of the current iteration and indicate the rating used for the overloaded branches of each one and; the two auxiliary (iteration specific) sets (p_cases20_inf, p_cases20_exc) that indicate the results of the analysis that followed the solution of the P-SCOPF at the new temporary operating point (i.e. the contingency analysis, the short-term rating allocation and the solutions of the Post-Contingency OPFs).

The contingency and rating selection steps can then:

- Redistribute cases across p_cases20, p_cases20_red and p_cases100
- Add contingency cases not previously included in any of p_cases20, p_cases20_red and p_cases100 to either p_cases20 or p_cases100

The two sub-processes of the contingency and rating selection step (C1 and C2 in Figure 4-9) run one after the other. Sub-process C1 is used for contingency cases where the post-fault overload at the new temporary operating point exceeds the 'default' or the 'reduced' short-term rating (so it handles the cases added to the the p_casesJ_exc set in step B7). Sub-process C2 is used for contingency cases where the post-fault overload at the new temporary operating point does not exceed the short-term rating but the Post-Contingency OPF does not return a solution (as in the cases that were added to the p_casesJ_inf set in step B8).

Once it is established that a case needs to be considered for preventive actions and be included in the P-SCOPF (i.e. corrective actions do not apply at the new temporary operating point) the least restrictive 'default' short-term rating is always trialled first[105] (the case "enters" the P-SCOPF through the p_cases20 set). The case is successively "moved" to the more restrictive sets (p_cases20red and then p_cases100) only if the using the rating of the previous set proves insufficient.

[105] The exception is when the Post-Contingency OPF that took place before the contingency and rating selection step was infeasible. In that instance, the contingency case enters P-SCOPF through the p_cases100 set.

Table 4-8: Step-by-step description of the contingency and rating selection step

Sub process	Description
C1	Sub-process C1 handles contingency cases where the post-fault overload at the new temporary operating point exceeds the short-term rating (these cases were added to p_casesJ_exc in step B7). For each case k of p_casesJ_exc: • If k is in p_cases20_red: the 'reduced' short-term rating was used for the overloaded branches of the case in the P-SCOPF. As the rating was found to be exceeded use the continuous rating in the P-SCOPF of the next iteration (move the case to p_cases100). • If k is in p_cases_20: the 'default' short-term rating was used for the overloaded branches of the case in the P-SCOPF. As the 'default' short-term rating was found to be exceeded but a 'reduced' short-term rating has not been trialled, use the 'reduced' short-term rating in the P-SCOPF of the next iteration (move the case to p_cases20) • If k is not in p_cases20 or p_cases20_red: the case has not been included in the P-SCOPF yet. Use the 'default' short-term rating for the overloaded branches of the case in the P-SCOPF of the next iteration (add the case to p_cases20)
C2	Sub-step C1 handles contingency cases where the post-fault overload at the new temporary operating point does not exceed the short-term rating but the Post-Contingency OPF does not return a solution (these cases were added to p_casesJ_inf in step B8). • Use the continuous rating for the overloaded branches of the case in the P-SCOPF of the next iteration (remove the case from p_cases20 or p_cases20_red – as applicable – and add it to p_cases100)

Note that once a case is added to one of the three main sets (p_cases20, p_case20red and p_cases100), it can only remain in that set or move to a more restrictive one. So, the total number of cases (across all sets) considered in the P-SCOPF through successive iterations can only grow or remain the same[106].

This feature was chosen to ensure the convergence of the iterative QB coordination framework within a finite number of iterations. It was found that removing cases from the P-SCOPF consideration (removing them from all sets) or "hot starting" the solution from an intermediate point could result to cycling of the algorithm: cases removed from would need to be added back to the P-SCOPF consideration in one of the next iterations.

As a result, the set of considered cases of the final iteration J may contain redundant cases that do not produce OPF constraints that are active at the optimal solution. This is not expected to

106 The number of allowed iterations (4) was determined from the max number of steps/iterations that a case needs to transition from not being considered in the P-SCOPF to being secured to the continuous rating.

influence the optimal solution that will be determined by the “critical” contingency cases (section 4.1.2) that are also included in that final set.

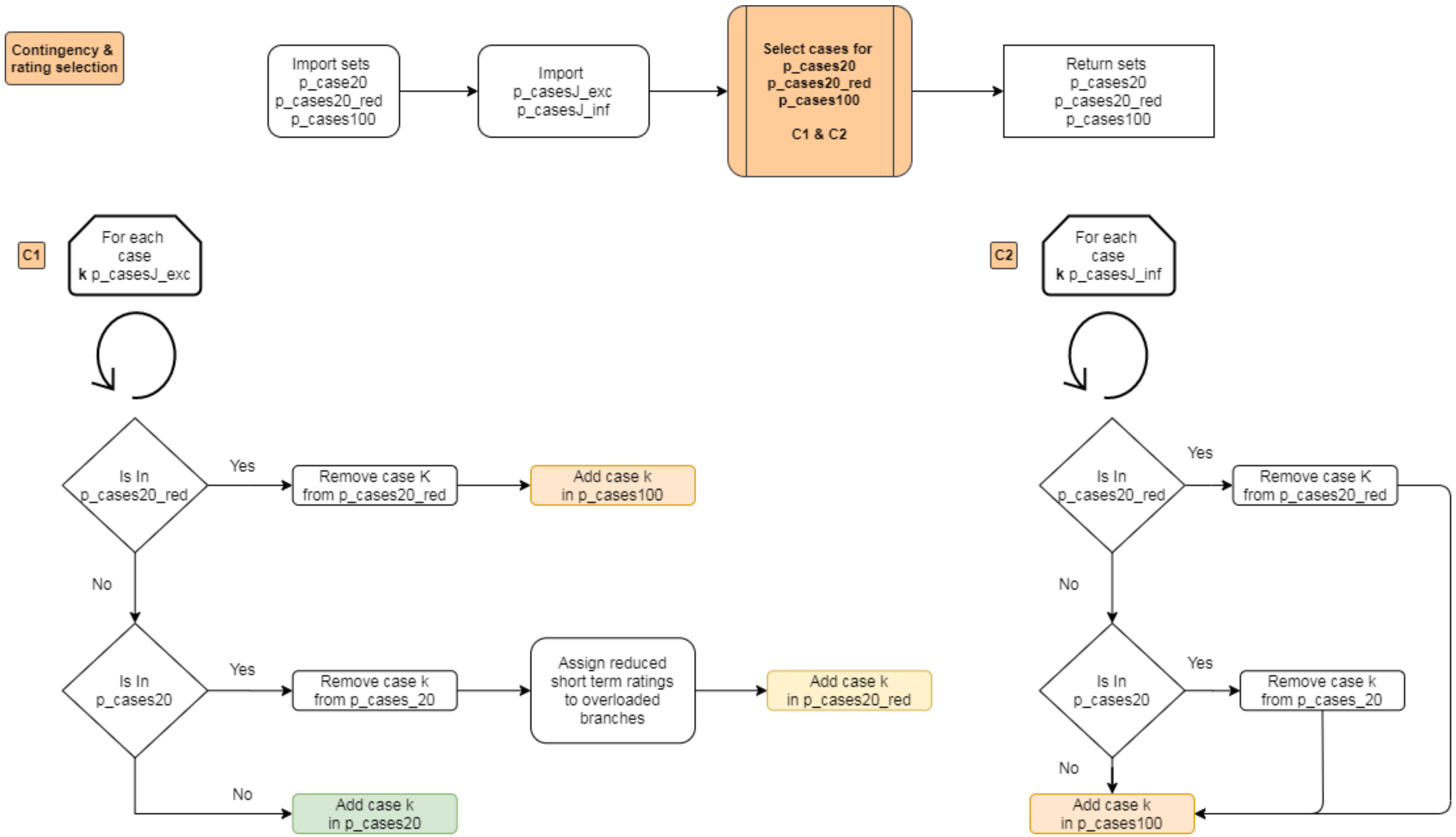

Figure 4-9: Contingency and rating selection step adds to or redistributes cases across the “p_cases” sets

5 Study set up, strategies and results

In this chapter, a study is setup to test the QB coordination framework developed in section 4.3 and help draw conclusions. It includes a number of strategies regarding the preventive and corrective use of QBs through the framework that are applied to a test network model. Strategies are compared on the basis of the preventive generation re-dispatch cost they achieve over the course of a simulated year of operation.

It is recommended that, if able, QBs must be used for both preventive and corrective actions in a coordinated way and to a high ‘extent’ (strategy D2 or D3 in the following). In practice this means that QBs of multiple network locations are used for corrective actions (instead of devices of a single location) and all devices are utilised for preventive actions (instead of the ones deemed ‘most effective’ towards the active network constraints).

The analysis showed that, use of QBs in the described way can result in a 36% reduction in the preventive generation re-dispatch cost, in the course of a simulated year of operation, over a strategy where QBs are not used at all for either preventive or corrective actions or 8.6% over a strategy where QBs are used for preventive and corrective actions but not to as high an ‘extent’ (strategy C2 in the following – baseline strategy).

5.1 Workflow for study set up and framework application

This section first describes the spatial and temporal modelling choices [161] that were made in order to obtain results regarding the preventive and corrective use of QBs through the coordination framework, namely:

- The choice of an appropriate branch and node test model
- The choice of generation and demand dispatch snapshots and how they were applied to the test model

Figure 5-2 provides an overview of the workflow described above. The details about each of the steps of Figure 5-2 can be found in Appendix E: Study setup. Following that, Figure 5-3 summarises how the QB coordination framework is applied in each dispatch snapshot of the test model and the output data that are collected.

5.1.1 Introduction of the test network model

The test system (Figure 5-1) is based on the “Representative GB Network Model” [162], [163] that was developed at the University of Strathclyde by the author. It is a simplified, scaled down version of the actual GB transmission network. It preserves some of the key limitations for transferring power across the different regions of the GB network and it includes the “groups” of QB transformers in the appropriate locations[107], the west coast embedded HVDC link and the GB to EU and to Northern Ireland interconnectors at the appropriate locations. Appendix D: Test network data includes more info on the test system and the detailed network data.

107 PEWO and DEES QB pairs belong to “west” group, KEAD first and second QB pair to the “east” group. STSB single QB device is in the “central” group and the GRAI and LOND QBs are part of the “south coast” group.

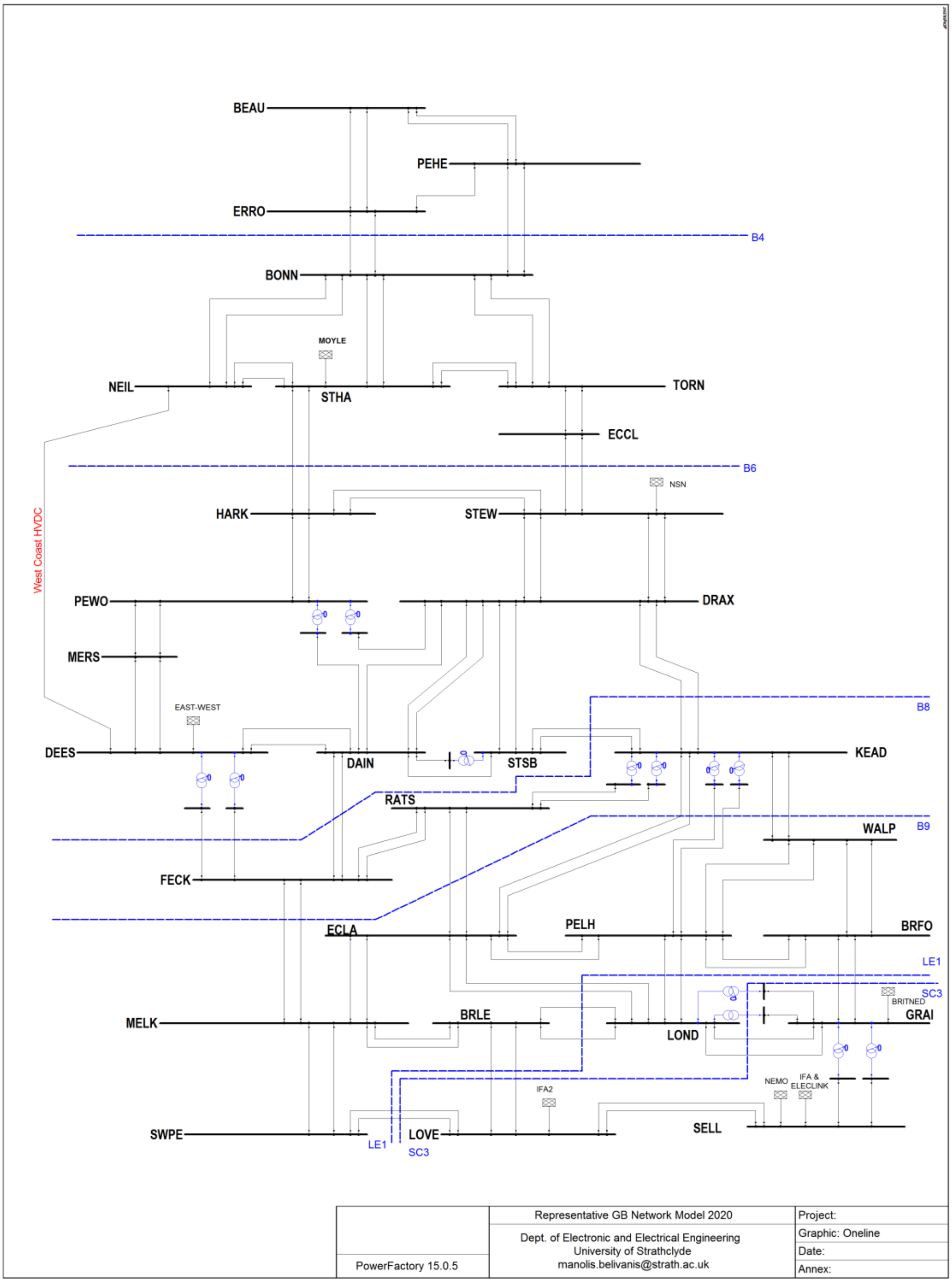

Figure 5-1: Representative GB network model – 2020 edition

5.1.2 Obtaining dispatch snapshots

Generation and demand capacity and year round dispatch

Generation capacities and demand were obtained from National Grid Future Energy Scenarios (FES) 2016 data set[108]. The FES team produces four scenarios every year that are based on government policy and aspirations, market intelligence and industry consultation. The scenarios present a number of possible future outcomes in the long term GB energy landscape and help model uncertainty in the network development process (section 2.1.3). In 2016, two main drivers were considered: “economic prosperity” and “green ambition”. Four scenarios/sensitivities were produced: “Gone Green”, “Consumer Power”, “Slow Progression” and “No Progression”. The Gone Green scenario represents a future where both drivers are very important and features a high volume of renewable/distributed generation and interconnection.

The scenarios provide an estimate of the expected generation, demand and interconnection capacity in each zone of the GB system. Different dispatches of generation and interconnectors and/or different demand levels will result in varying flows across the network.

There is more than one ways to obtain dispatch snapshots from the FES dataset that can provide insights about the behaviour of the GB system when applied to the test model. Some of them are briefly mentioned below. Note they can be combined in more than one way:

- Through probabilistic variance of certain dispatch variables
- By varying certain dispatch variables in discrete steps as in [97]
- Using historic data about demand level and/or renewable energy resource
- Using the Economy or the Security Criterion of SQSS [4]
- Solving an economic dispatch problem.

For the results presented later in this chapter, the National Grid Electricity Scenario Illustrator (ELSI) model was used to produce a year round economic dispatch. ELSI combines historic/statistical data about demand and renewable energy resource in GB and solves an economic dispatch problem in each dispatch period[109] . It also takes into account the expected availability of the different types of generation. More information about ELSI and the obtained year round market dispatch can be found in Appendix E: Study setup. For the results of section 5.3, the year 2020 of the FES 2016 Gone Green scenario was used.

108 The Electricity Scenario Illustrator model (ELSI) was provided with the FES 2016 data set. This is why FES 2016 was used.
109 Note fuel prices and other data required to calculate wholesale cost of energy are also included in the FES dataset.

Convert zonal to nodal generation dispatch

The FES are “macro-scenarios” that apply to whole of GB. ELSI provided a zonal allocation of the FES 2016 demand and generation forecast in GB using 40 geographical zones [164]. The zonal approach allows flexibility when developing the scenarios and it can be naturally extended to model network limitations using the concept of boundary.

When using a branch and node model to explicitly represent power flows on the network branches and test the use of power flow control devices, the zonal generation and demand has to be allocated to specific network nodes. This was done using info from [164] that indicates which geographic area each ELSI zone covers. It was combined with info from Figure Ap. -4 that indicates the substations of the GB network that are “included” in each test network node. The detailed allocation is provided in Appendix D: Test network data

Dispatch of the western HVDC link

In this step a simple rule is applied to obtain an initial HVDC link dispatch for each dispatch snapshot. The rule gradually increases the HVDC dispatch set point as the excess generation in Scotland (relative to demand) increases. The link is dispatched to its full capacity when the excess generation exceeds 3500 MW.

The link is part of the GB transmission network and its output can be directly controlled by the ESO. The rule only aims to provide a reasonable starting point for the QB coordination framework. The initial link dispatch will be re-adjusted in the first iteration of the framework if required as the dispatch of the link is a control variable. More info on the rule and the use of the link as a control variable can be found in Appendix E: Study setup.

Application of planned outages

Access to the network is required for the following reasons [165]:

- Asset maintenance or replacement
- User connection works
- Construction and connection of network reinforcement options

To safely gain access branches or busbar sections must be taken out-of-service. These “planned” outages are scheduled in the spring and summer period both for health and safety reasons and because the network is less stressed in off-peak periods so the degradation of network capacity is expected to have less of an impact in terms of constraint cost. When possible transmission network outages are coordinated with those of power stations for the same reason.

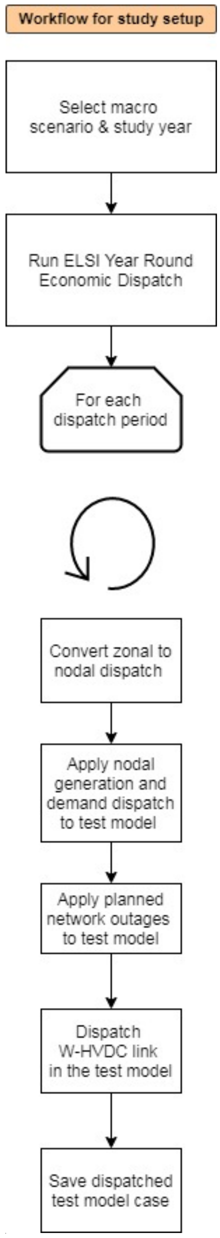

Figure 5-2: Workflow for study setup

5.1.3 Applying the QB coordination framework

Following the study setup process of section 5.1, Figure 5-3 summarises the workflow for using the QB coordination framework. The framework is applied in each dispatched test model case – that encapsulates the data of a dispatch snapshot applied to the node and branch test model – in turn.

Input data that have to be provided to the framework at this stage are the strategy that determines how the active power controls are used (see section 5.2), the list of contingencies that need to be considered and the list of network elements (branches) that need to be monitored for overloads (Appendix E: Study setup). For the study setup and the results of this chapter, we assume a static set of contingencies. They are defined using the 'N-1' and 'N-D' security criteria in the test model. The full list can be found in Appendix E: Study setup

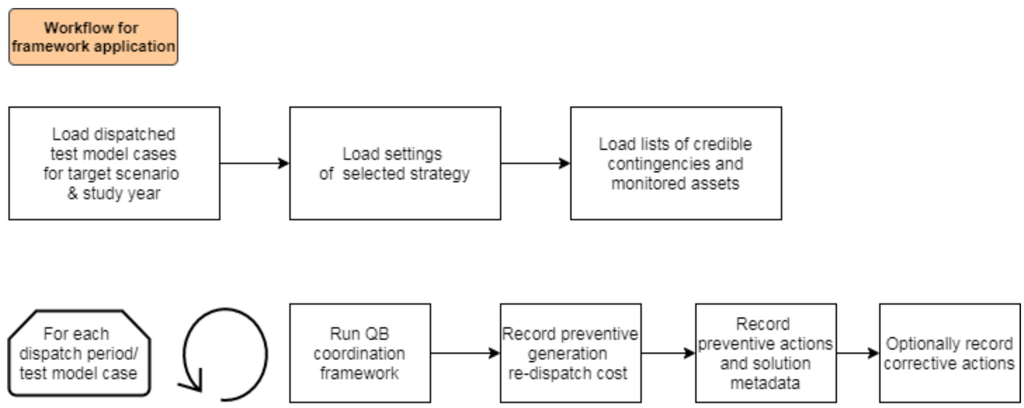

Figure 5-3: Workflow for framework application

5.1.4 Interpreting the results and making use of the output

For each dispatch period a number of outputs are recorded (Figure 5-3). At a high level, the main output that needs to be recorded is the preventive generation re-dispatch cost[110] (section 4.2.2). This an indication of how effective a strategy is overall. Comparing the settings of two strategies with the difference in the achieved cost can help draw conclusions on the best use the active power controls and what can be achieved with "operational"[111] measures only.

The detailed solution data of each dispatch period can be used for further analysis. The BMUs and QBs that the P-SCOPF utilised in the optimal solution (and the volume of MW re-dispatched) can help drive the procurement of enduring (long term) contracts for constraint management services from network Users – such as generators or demand clusters[112]. Using commercial services agreed ahead of time – instead of through the balancing mechanism or

110 Generation coming either from GB connected generators or through interconnectors.
111 Note that operational measures also require investment in assets such as IT systems and/or communication and control hardware.
112 In most cases more than one BMUs in a region can be considered for these services - not exclusively the ones that the P-SCOPF used.

day ahead trading – can help achieve a lower cost for operating the network in the long term [14], [166]. The P-SCOPF solution can provide insights such as the geographical location and the required capacity or volume of the service. It can act as the "counterfactual" and help determine a target price for the service.

Another output is the OPF constraints/network branches that are 'active' in the P-SCOPF solution and the contingencies that trigger them. The former indicate where investment in network capacity must be directed to achieve a reduction in operating cost. The relative reduction of the objective function value with the increase of the capacity of an 'active' branch by one unit (shadow price of the constraint) can indicate which branch/area of the network must be targeted next and provides a measure of the expected benefit of reinforcing that branch/area[113]. Examples of similar sensitivities used in network planning are provided in references [9] (Key Message 3) and [17].

Knowing the contingency case that triggers an 'active' constraint is also important. In certain cases, it may be possible to limit its impact by changing the running arrangements[114] of the network, deferring a planned outage, limiting its duration or aligning it with that of a power station.

Further, when the framework is used in the operational planning timeframes (year ahead) the proposed corrective actions (the solution of the Post-Contingency OPF problems) can also be recorded and analysed. The number of control actions or the different areas where the OPF requires controls to be used can be indicative of the "effort" required to control post-fault overloads and a measure of the complexity of operating the network with the corrective paradigm in the specific circumstances. That complexity can be compared against the achieved constraint cost. Thus, the detailed Post-Contingency OPF framework output can support decision making in operational planning. If an acceptable level of complexity is exceeded alternative/additional methods for securing the network or for applying the required corrective actions may be sought. An example could be the procurement of automated post-fault services from market participants (for use in short term) [151].

Finally, if the framework is used at even shorter timeframes when the SO engineers prepare actions for the control room ahead of the actual operation (two days before operation or sooner), the P-SCOPF and Post-Contingency OPF actions of each dispatch period can be the

113 Note that when planning for transmission network reinforcement options the sensitivities of the OPF solution must be used as a guide only. As with any sensitivity factor there are some limits to their validity and their intended use. To capture the impact or the possible benefit of a candidate reinforcement the framework has to be re-run with it in the background.

114 The internal connections between substations busbars can merge or split the substation to a single or several electrical nodes.

basis[115] of the preventive set of actions and the corrective action plans submitted to the control room [34].

5.1.5 Implementation details

The framework is currently implemented in Mathwork's Matlab development environment. The Matpower [167] open source power system analysis toolbox is used for running power flows. The code that implements the framework stages, forms the optimisation models and invokes the solvers is custom and was written for this application using the Matlab programming language/development environment.

The solvers used to solve the OPF models are the "linprog" (dual simplex) for linear models and the "intlinprog" (dual simplex and branch and bound) for the mixed integer linear models. Both can be found in the Matlab's Optimization toolbox. Binary variables are defined as integer variables in the MILP model with bounds [0,1].

Regarding execution times, it takes approximately 30 seconds for the framework to "solve" one dispatch period (including – optional – textual output but not the detailed output[116]) on a 64-bit 2.1 Ghz core[117]. From that, approximately 20 seconds are used for forming and solving the various P-SCOPF and Post-Contingency OPF models[118]. Running the analysis for a one simulation month requires between 11 and 22 minutes (varies between strategies and months). Times are specific to the hardware, study setup, applications used, data interfaces and other implementation and coding choices made. Priority has been given on the proof of concept and principles rather than deployment. Note that deployment in a production environment would require the code to be compiled and it is likely that a database would be used for data input and output and distributed computing power would allow for faster cores and parallelisation of the contingency analysis, the Post-Contingency OPF solutions or the dispatch period solutions.

115 Action plans for real time operation must take into account the reactive loading of the lines and the voltage magnitude and voltage step changes at busbars before and after a contingency. Since the framework is based on the DC power flow approximation and makes use of the active power controls only, each set of actions produced by the framework can only form the basis of that plan. Their validity must be tested with an AC load flow and they may need to be adjusted or augmented with reactive power control actions.

116 Detailed output only needs to be collected once several dispatch periods are solved (e.g. a simulation year). It is extracted through the Matlab interface to Excel.

117 Exact specifications are a 64-bit 2.1 Ghz 8 core processor and 8 GB of ram. However, the applications used (Matlab and the optimiser) are designed to use a single core at a time.

118 Approximately 0.3 seconds are needed to form and solve a single state post-contingency OPF model and 1.5 to 2.5 second for a P-SCOPF model

5.2 Strategies

This section will describe the strategies used to demonstrate the operation of the QB coordination framework. A strategy is a set of settings regarding the use of QBs and other controls. Each strategy aims to achieve a slightly different operational or planning objective or serves a different priority of the system operator. Within the settings/limitations of each strategy, the framework will provide a solution that secures the system in every dispatch period with as low a preventive generation re-dispatch cost as possible. Table 5-1 summarises the strategies used. The strategies should be considered in the context of this thesis only and not as definitive of how the ESO is using the QBs. For the latter refer to the information in [8], [34].

Table 5-1: Summary of settings regarding the preventive and corrective uses of controls in the examined strategies

	BMUs		**QBs**	
Strategy	**Pre-fault**	**Post-fault**	**Pre-fault**	**Post-fault**
A1	most effective[119]	not used	kept neutral	not used
A2	most effective	not used	± 6 taps (most effective)	not used
B1	most effective	limits on use[120]	kept neutral	not used
B2	most effective	limits on use	± 6 taps (most effective)	not used
B3	most effective	limits on use	± 6 taps (all)	not used
C1	most effective	limits on use	kept neutral	single QB or pair
C2	most effective	limits on use	± 6 taps (most effective)	single QB or pair
C3	most effective	limits on use	+/- 6 taps (all)	single QB or pair
D1	most effective	limits on use	kept neutral	all QBs
D2	most effective	limits on use	± 6 taps (most effective)	all QBs
D3	most effective	limits on use	± 6 taps (all)	all QBs

In the strategies that use QBs for preventive actions, the ± 6 tap deviation from neutral setting is an interpretation of the "QBs are operated close to neutral tap position" clause mentioned in [8]. In the strategies that use BMUs or QBs for corrective actions, the bounds of the Post-

119 Selection of effective controls takes place according to the method of section 3.4.4
120 Limits aim to keep the volume of generation that can be re-dispatched to a realistic level to avoid "false positives" by the Post-contingency OPF. How it is achieved is explained in Appendix E: Study setup.

Contingency OPFs are calculated explained in section 3.1.4 and provided to the OPF model i.e. the preventive model (P-SCOPF) and the corrective models (Post-Contingency OPFs) are not directly coupled. The pre-fault position of the control, the rate of change and the time available for corrective actions are all taken into account when calculating the bounds.

Although more than one strategies could find use depending on the operating conditions, for the results presented in section 5.3, strategy C2 should be seen as the baseline/counterfactual strategy.

Note that, although not explicitly shown in Table 5-1 the west coast HVDC link and the GB to EU and to Northern Ireland interconnectors are available as control variables in every strategy. They are used with the same features/limitations explained in section 3.3 and Appendix E: Study setup. For the reasons explained in section 3.3, the total volume of Bids accepted for post-fault generation re-dispatch is limited to 1000 MW in order for the change of generation and demand balance immediately after accepting Bids to stay within the limits of the frequency containment service.

5.2.1 Strategies A: System secured with preventive actions only

As no corrective actions are used in these strategies, the system has to be secured with preventive actions only. In strategy A1, QBs are kept at neutral tap throughout while in A2 each QB is allowed to deviate by ± 6 taps from its neutral setting.

Strategies A are more conservative than how the SOs operate the system today or how they plan to operate in the short term/mid-term horizon when it comes to managing thermal constraints and they are included here mostly for comparison. Inevitably, they result in increased preventive generation re-dispatched cost when compared to the subsequent strategies.

They can, however become relevant under certain circumstances. One of these is when in long term transmission expansion planning (investment planning) the SOs aim for a more conservative use of transmission system capacity and chooses to not consider the headroom provided by the short-term ratings. Due to the increase in the forecasted constraint cost it is likely that additional network reinforcement options may also be required – where economically justified when compared against the increased constraint cost. By not considering that headroom, a safety margin is incorporated in long term planning that ensures the system remains operable under a wider range of possible future generation and demand outruns. In that sense, it can be thought as producing a more robust long term investment strategy.

Strategies A1 or A2 are also relevant when there is/expected to be a ‘stability’ network limitation – where fast acting transient or dynamic phenomena would be initiated after a transmission fault that will endanger the integrity of the system. In that case, the system would have to be secured against the fault by reducing/changing the pre-fault power flows through certain areas/boundaries as most post-fault actions may not applicable. Strategies A can then be used to capture the cost of preventive generation re-dispatch over a longer period of time that can be compared to the cost of alternative options[121] for managing or mitigating the stability issue. In that case, strategies A1 or A2 may need to be applied to a specific set of contingencies only.

Finally, by keeping the QBs on or close to their neutral tap setting at pre-fault/preventive operation, the SO could aim to achieve one or more of the following objectives:

1. Preserve more of the dynamic range of the QBs for post-fault actions
2. Preserve more of the dynamic range of the QBs for use during the operational planning phase to help better accommodate planned outages. Planned outages, that last for a number of weeks each year and can take place in different parts of the system at the same time, and often create new, temporary ‘weak’ points on the system. By assuming QBs are kept at or close to neutral tap at long-term planning, there is more flexibility on how the devices can be used at operational planning/operation.
3. Reduce the overall wear and tear on the devices.

5.2.2 Strategies B, C and D: Alternative paradigms for using QBs for preventive or corrective actions

Regarding the preventive use of QBs, strategies B, C and D test the following three options respectively. QBs devices are either:

- kept at neutral tap setting (not used), or
- used within ± 6 taps of neutral tap setting (only the ‘most effective’ devices used – as defined in section 3.4.4), or
- used within ± 6 taps of neutral tap setting (all devices used)

Strategies B, C and D also test different ways QB devices are used for corrective actions. In Strategies B, QBs are not used for corrective actions and remain at the neutral tap or at the tap set by the P-SCOPF for that dispatch period. In Strategies C, only a single QB or pair of devices (located in the same substation) can be used for corrective actions[122]. Note that

121 The alternative options could be asset based or non-asset based (a long term contract for services from certain network Users)
122 The limitation is enforced in the Post-Contingency OPF with a constraints limiting the max number of controls as explained in section 3.4.3

according to [8] this is the 'business as usual' or the counterfactual strategy of this study as it resembles what the ESO is currently aiming for regarding corrective use. Strategies D finally remove that restriction and all QB devices can be used for corrective actions as required. Each of the strategies B, C and D has three variations regarding the preventive use of QBs as explained in the previous paragraph.

In any case, a limited number of tap changes are assumed possible from each individual device within the time available for corrective actions (Appendix E: Study setup). That limit – also adapted from [8] – ensures that there is enough time to physically implement (instruct, monitor and confirm) the tap changes as tap changers are electromechanical devices (see Appendix A: QB technology).

Note that across strategies B, C and D, BMUs and the other controls are used in a consistent way so that comparison is possible (Table 5-1). In particular, only the 'most effective' BMUs are used for preventive actions (as described in section 3.4.4) and there are some limits imposed in the post-fault use of BMUs to make sure that, given the limited time available for corrective actions, both the volume and the number of BMU post-fault actions (Bids and Offer acceptances) are kept at a realistic level (detailed in Appendix E: Study setup). This is to avoid the Post-Contingency OPF returning "false positives" when a contingency case is marked as correctable because the OPF is able to use a not realistic volume of power or number of controls. Note also an overall limit of 1000 MW on the total volume of Bid acceptances is also used throughout (as explained in section 3.3).

In the absence of automation (as explained in section 2.2.4 and in [8], [49]) manual switching of taps is the default way to use the QBs in GB at the time of writing, so using more QBs for post-fault actions than the default "single device or pair" is increasing the workload of SO engineers at times when the network is experiencing an overload and it is more vulnerable as its capacity is depleted because of the fault outage. Further, it increases the complexity of the proposed action plan. Using BMUs for corrective actions tends to be more straight-forward and easier to implement. All accepted Bids tend to reduce the flow on the overloaded circuit. QBs redistribute the flows away from the overloaded circuit often increasing the flows on other ones. So there is larger number of circuit ends whose flows will be changing and need to be monitored when applying the corrective actions.

However, by using more QB devices for corrective actions it is possible that more cases will become "correctable", would not require preventive actions and would not need to be included in the P-SCOPF. This could in turn could reduce the preventive generation re-dispatch cost.

5.3 Results

Note the results presented in this section (and in the Appendixes) should only be viewed in the context of this thesis. They are specific to the study setup and the input data used. Only publicly available input data were used. The constraint cost figures, either in absolute or incremental form (as for example when comparing two strategies), should not be taken as definitive of the constraint cost expected to be incurred in the actual GB network (or the cost that was incurred in 2020). For the latter please refer to the information the ESO has made available through its publications [168] or the data portal [169].

5.3.1 Overview of network flows and network constraints

The prevailing power flows across the test model (Figure 5-4) in our study case are determined by the following two factors. The first is the overall disposition of generation and demand. There is an excess of installed generation capacity relative to demand in Scotland and in the north of England[123] and an excess of demand relative to generation further south in England and in the wider London area. A large proportion of the installed generation in Scotland comes from wind or other renewable energy sources. Because of the high wind resource[124], wind generation frequently displaces thermal generation located in more southern areas. Further, offshore wind capacity in the north west of England and in north Wales[125] results in export power flows from these areas to the rest of the system. The above combined mean that, at times of high wind resource or high network demand, “export” power flows from Scotland and “north to south” flows across the test model are experienced.

The second factor is the south coast interconnector flows. In the Gone Green 2016 Future Energy Scenario, the forecasted renewable generation capacity of Great Britain in the year 2020 is not yet fully developed and it is mostly used to cover the national demand. In the ELSI market dispatch for 2020, the interconnectors in the south coast of England are mostly importing energy to GB that is produced by cheaper energy sources in Europe. This results in increased power flows across the south coast branches as energy from the interconnectors flows towards London.

The prevailing flows result in overloads on a number of network branches (Figure 5-4– in red) after one or more of the credible contingencies[126]. Only the most “severe” overloads are shown: branches that, on average, exceed their continuous rating the most or more often over

123 In the test model, Scotland is modelled by the nodes “north” of boundary B6.
124 That is considered in the ELSI economic dispatch model.
125 In the test model, these areas are modelled by the nodes PEWO, DEES and BRFO respectively
126 Credible contingencies and monitored branches as per Appendix E: Study setup

the course of the study period. The overloads are recorded before any preventive or corrective actions take place, i.e. before the application of the QB coordination framework. During the contingency analysis all QBs are at neutral tap and the W-HVDC set point is determined as in 5.1.2.

It is evident in Figure 5-4 that the majority of the severe overloads take place in the Scottish border area or in the north and north west of England. This can be explained by the prevailing flows described previously but also due to the more limited network capacity in these areas. Indeed, there is a higher number of parallel circuits further south or on the east side of the test network which means that a higher volume of flows can be securely accommodated through them.

Appendix F: Year round market dispatch and network constraints provides more detailed information about the generation dispatch, the network flows and constraints experienced in the test network, as per the study setup and the input data used. Please refer to references [9] and [1] for info regarding the actual GB system on the same matter.

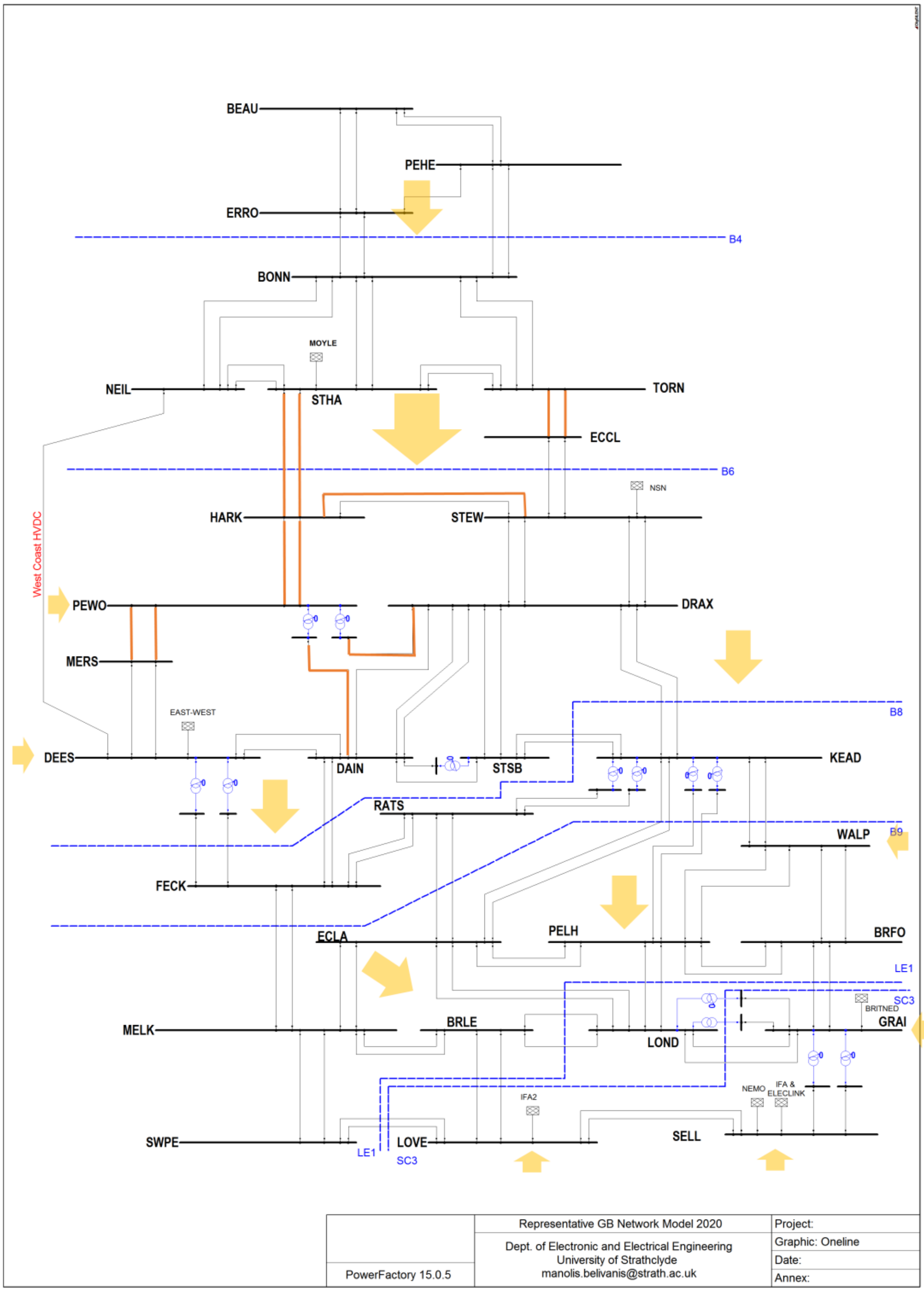

Figure 5-4: Prevailing network flows (yellow) and network constraints (red)

5.3.2 Overview of results

Figure 5-5 compares the annual preventive generation re-dispatch cost of each strategy. Strategies A1 and A2 feature by far the highest constraint cost figures because no corrective actions (either by BMUs or QBs) are used. In strategy D3 where restrictions regarding the preventive or corrective use of controls are removed, a considerable lower cost figure can be achieved. The cost of strategy A1 is almost double that of D3. The remaining strategies achieve a cost between these two extremes.

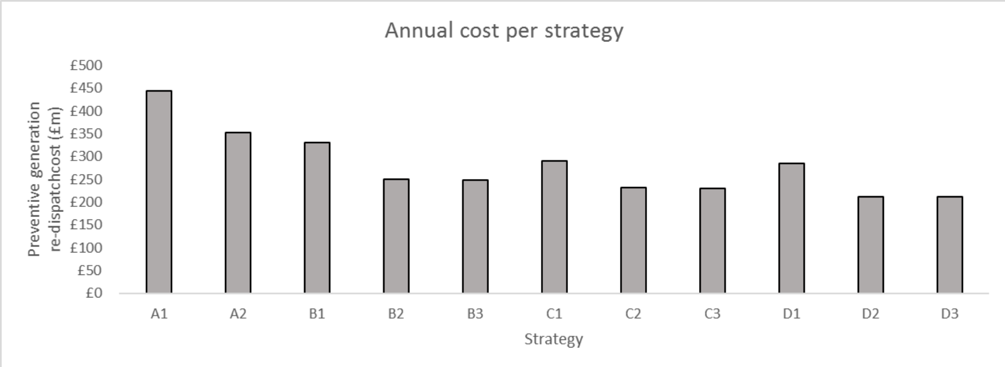

Figure 5-5: Overview of annual cost of each strategy

Figure 5-6 shows the monthly break down for strategy C2. The highest cost is incurred in December. December is the month of peak network demand (winter in GB). High north to south flows across the test model take place throughout the month. May by comparison is a month of low network demand and by consequence lower volume of north to south flows. Appendix G: Detailed results includes the monthly breakdown of the other strategies.

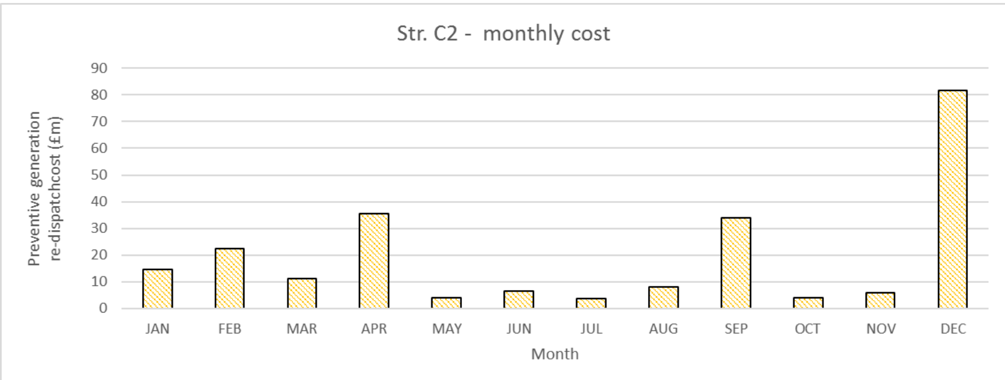

Figure 5-6: Monthly break down of cost

5.3.3 Factors that determine the preventive generation re-dispatch cost

In any dispatch period, the following factors will determine the cost of preventive generation re-dispatch:

- The contingency cases whose network constraints can be secured with corrective actions only.
- The contingency cases whose network constraints must be secured with a combination of preventive and corrective actions or only with preventive actions – to the extent that including them in the preventive SC-OPF produces an 'active' OPF constraint in the optimal solution.
- The cost of the controls made available for preventive actions
- The coordination between the controls to ensure that the most expensive controls are used as little as possible.

The way the QBs are used both for preventive or corrective actions will influence the constraint cost through all the factors described above. More specifically:

a) The extent of the use of the QBs for corrective action because it will affect if contingency cases can be secured partially or fully with corrective actions or if they need to be included in the P-SCOPF. Extent is defined as the number of QB devices or pairs made available (none, single device/pair, multiple devices/pairs) and the number of tap changes allowed in each.
b) The extent of the use of the QBs for preventive actions because it will affect the cost by changing the volume of generation re-dispatched needed. More specifically, the volume that must be procured from expensive to re-dispatch generation types (renewables or interconnectors). Extent is defined as which devices are utilised for preventive actions (none, 'most effective' or all) and the number of tap changes allowed in each.

Figure 5-7 shows the annual cost of each of the strategies B,C and D against their settings for preventive and corrective use of QBs. These strategies can be used to compare how utilising the QBs changes the overall generation re-dispatch cost because they have identical settings when it comes to the preventive and corrective use of the other active power controls (BMUs and W-HVDC link).

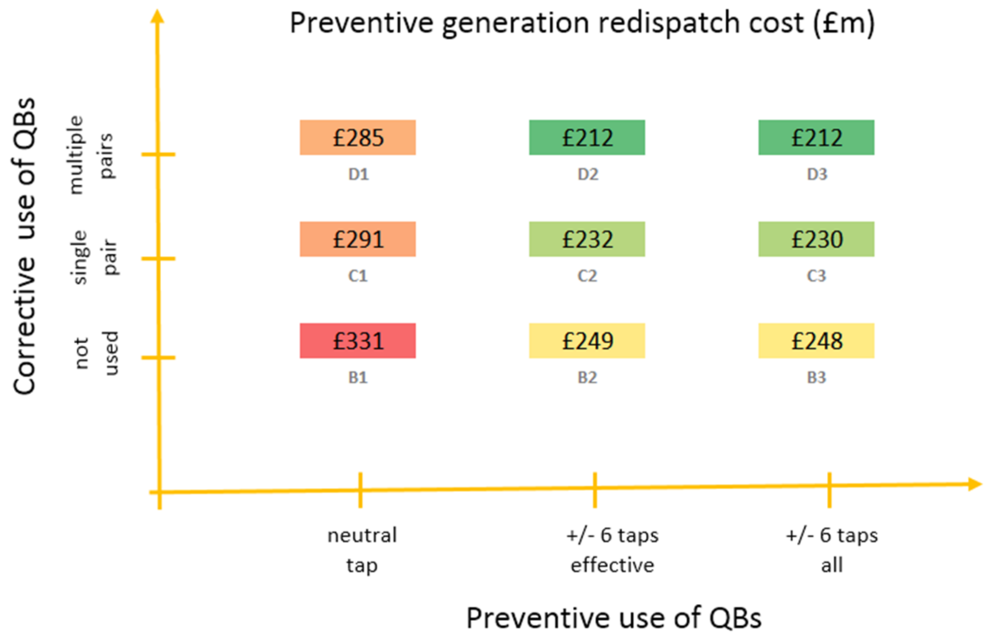

Figure 5-7: Impact of extent of use of QBs on constraint cost.

From Figure 5-7, the following conclusions and observations can be made:

First, to achieve the best possible reduction in constraint cost (point D3 in Figure 5-7), it is not enough to focus on improving[127] the preventive or corrective use of QBs only. Both aspects need to be improved.

Second, if only one of the two aspects could be improved, it can be seen (by comparing the change between point B3 and B1 with that between D1 and B1) that increasing the preventive use is, by itself, a more effective measure. It has the potential to significantly reduce the constraint cost even if QBs are not used post-fault (kept at their pre-fault tap). Increasing the corrective use only, while keeping QBs pre-fault at their neutral tap[128] is, in comparison, less effective. The achieved constraint cost reduction is 13% less than in the first case.

This can be understood as the preventive generation re-dispatch cost figure does not include the cost of any corrective actions. As explained in section 4.2.2, the cost of preventive actions, that is definitely incurred, is the measure of how effective a strategy is overall and it is the cost considered when making decisions in operational or long term planning. So utilising more QB devices/pairs for post-fault actions, even if it reduces the cost of the corrective actions, it does not directly account towards a reduction in the preventive cost.

[127] "Improving" relative to the no QB use – point B1

[128] In an effort to have more of their tap range available for corrective actions.

The mechanism by which the increased use of QBs for corrective actions affects the preventive cost is by enabling contingency cases to be secured with corrective actions, fully or partly. This means that the network constraints of those contingency cases will not be included in the P-SCOPF problem or, if they do, the higher short-term thermal rating instead of the continuous rating could be used. However, in most cases, the same effect can be achieved by using only the BMUs for corrective actions. It is expected that there will be enough generation dispatched and available in the Balancing Mechanism to be used for that purpose after the fault takes place. The cost of corrective actions will be higher if using the BMUs only but it will only be incurred if the fault takes place and thus it is not included in the constraint cost (preventive generations re-dispatch cost).

In certain occasions, a contingency case cannot be secured fully or partly with corrective BMU actions only. This could be due to the restrictions on the post-fault use of BMUs (regarding the volume of generation that can be Bid off or the number of BMU Bid acceptances that can be issued) that are factored in our analysis. Another reason could be the network characteristics in specific areas of the test network that necessitate the use of certain QBs. So a reduction in constraint cost is still possible by increasing the corrective use of QBs only (as can be seen in Figure 5-7 by comparing point B1 with C1 and D1).

The increase in the preventive use of QBs can directly and by itself influence the cost preventive generation re-dispatch when QBs and BMUs control actions are coordinated to achieve the same objective (Figure 5-7 points B1, B2 and B3). Section 5.3.3.1 provides more details of how this mechanism works in practice.

Finally, it can be seen that, having started using the QBs for both preventive and corrective actions (i.e. as in point C2 in Figure 5-7), increasing the preventive use only and making all devices rather than the ‘most effective’ ones available for preventive actions (point C3) has only a small impact on the constraint cost. Using multiple QB pairs for corrective actions, instead of a single pair (point D2), reduces the constraint cost further and it is now the most effective, additional measure.

To understand this one has to consider the mechanisms described earlier on how the preventive and corrective use of QBs influences the preventive generation re-dispatch cost not in isolation, but as interacting pieces of the network operation.

In the following, the detailed results from the output of the QB coordination framework are used to expand and confirm the conclusions and observations made above.

5.3.3.1 Extent of use of QBs for preventive actions

To mitigate the consequences of a fault with preventive actions, power system engineers must use active power controls to change the pre-fault network flows so that, following any fault, no branch exceeds its continuous rating (or its short-term rating if the case is secured partially with corrective actions). Depending on the circumstances, any combination of the following practices can be used:

- the output of generation in an exporting[129] area of the network is reduced in order to directly reduce the pre-fault loading of specific branches.
- the pre-fault flows through parallel branches are redistributed to improve the sharing of flow between them.
- the pre-fault flows of a wider area are diverted away from the "weak" links of the area all together.
- The pre-fault flows of a wider area are redistributed in such a way that less or less expensive generation re-dispatch needs to be used to secure the network.

The extent that QBs are used for redistributing and diverting flows can directly influence the extent that BMUs have to be used to directly reduce the pre-fault flow through specific network branches or weak links. The preventive QB tap settings have to be coordinated with the BMU actions to ensure that the most expensive to re-dispatch generation types are used least. This coordination can be inherently achieved by using the OPF method.

Constraint cost and energy re-dispatch savings through the coordinated use of QBs for preventive actions

To illustrate the above, data from **strategies A1 and A2** are used first. Both do not allow any corrective actions (from BMUs or QBs - Table 5-1) and the network is secured with preventive actions only. Since strategy A2 allows the preventive use of QBs while strategy A1 does not, any savings recorded is a direct and sole effect of the preventive use of the QBs.

Figure 5-8 presents the annual volume of energy that is constrained (by issuing Bid acceptances) broken down by generation type. Observe the difference in constrained GWh of onshore and offshore wind between the two strategies. As wind energy is one of the most expensive forms of generation to Bid off, in this study setup that is based on a simulated 2020 calendar year, this has a significant impact in the incurred constrained cost (Figure 5-9).

129 An area with large volume of excess of generation that is primarily exporting power to the rest of the network

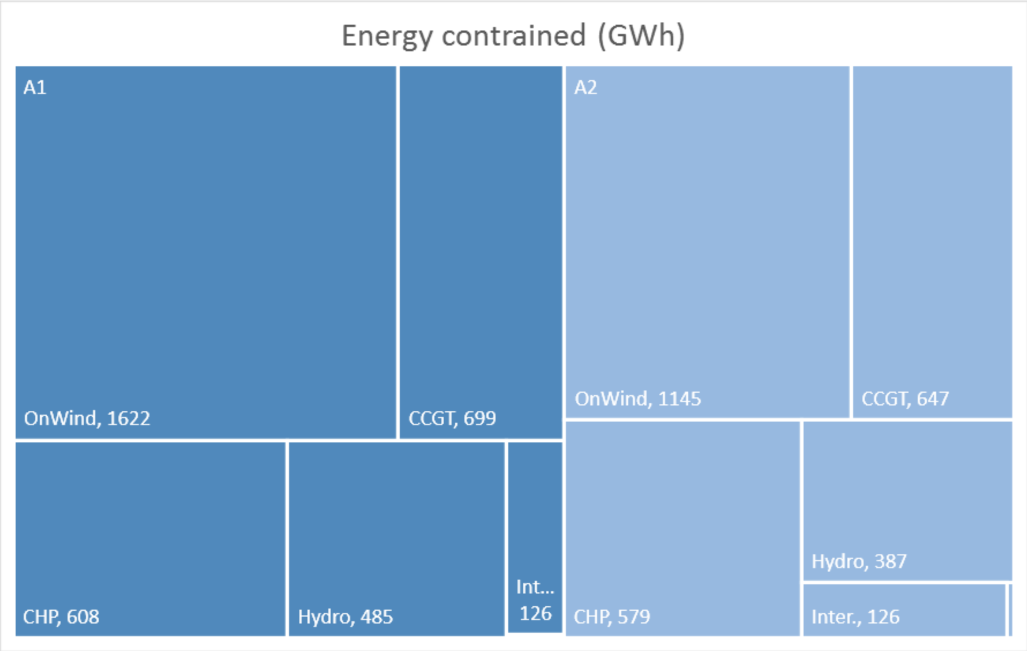

Figure 5-8: Energy constrained in strategies A1 and A2

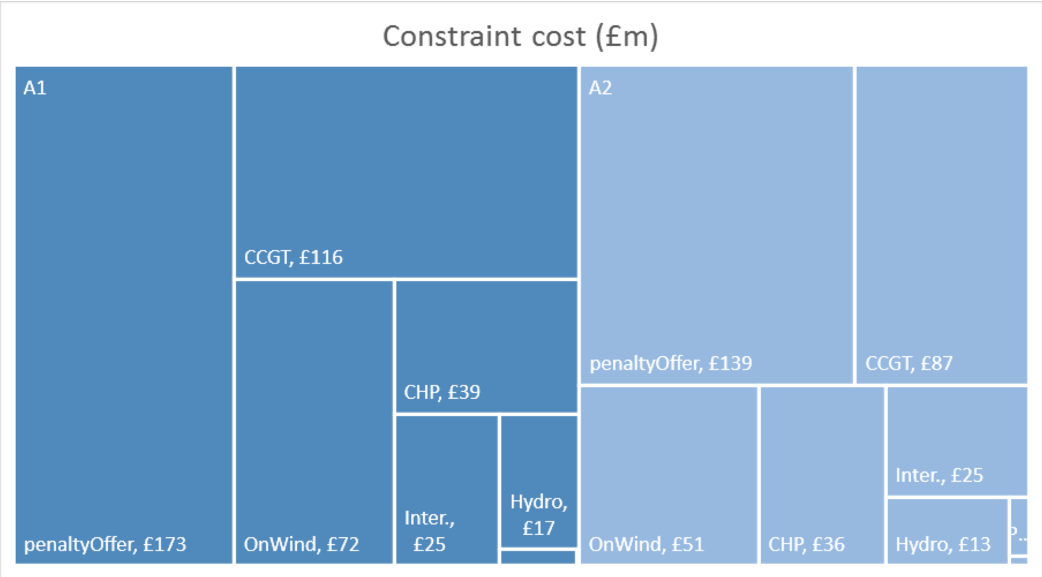

Figure 5-9: Constraint cost in strategies A1 and A2

To understand why wind needs to be constrained one must consider the prevailing network flows and network constraints (Figure 5-4) together with to the geographic allocation of generation and demand across the test network (Appendix F: Year round market dispatch and network constraints). The north to south flows across the test model – in the areas where network constraints appear (Figure 5-4) – are mainly driven by the wind generation exported from areas further north.

Use of the pre-fault QB tap settings (as in strategy A2) can redirect the pre-fault flows away from the overloaded circuits and limit the volume of wind energy that needs to be constrained to directly reduce the flows through the overloaded circuit.

The cost of replacement energy also adds up towards the constraint cost. Replacement energy is necessary to re-establish the balance of generation and demand. It comes from thermal generators (that, with sufficient initial headroom, can increase their output on request) that are located further away from the network constraints. It can be seen in Figure 5-8 that the majority of the cost of replacement energy is coming from the CCGT and "Penalty Offer" generation types. The difference in cost between strategies A1 and A2 is coming for the most part from the difference in use of those two types.

There are two factors at play here. The first one is the obvious one that, by reducing the volume of constrained generation (by coordinating the pre-fault QB tap settings) less energy is required to replace it. The second is that, at times of high wind output and medium or low network demand, wind generation is displacing the more expensive thermal generation in the unconstrained (market) dispatch. At certain dispatch periods throughout the year, the thermal generation capacity dispatched (synchronised) and the volume of energy that can be made available in the balancing mechanism (Offers submitted) by it is not be enough to replace the total volume of energy constrained. The "Penalty Offer" generation type is used in our analysis to capture this. The cost of using "Penalty Offer" is higher than the other generation types to reflect, for instance, the cost of "starting up" and making available to the ESO a thermal generator that it is not economic to run. The cost of replacement energy is often overlooked but, when accounted for, it can provide additional arguments for the coordination of preventive QB tap settings.

Next, we use data from strategies **B1, B2 and B3**. They utilise BMUs for corrective actions, so they incur less constraint cost (and less use of the penalty variables) than A1 or A2 overall. The extent of use of QBs for preventive actions increases from B1 to B3 (Figure 5-10). It can be seen that using strategy B2 instead of B1 the constraint cost is expected to be less in all months with the highest decrease in December. Using B3 – where all QBs are available – offers only marginal additional reduction in constraint cost.

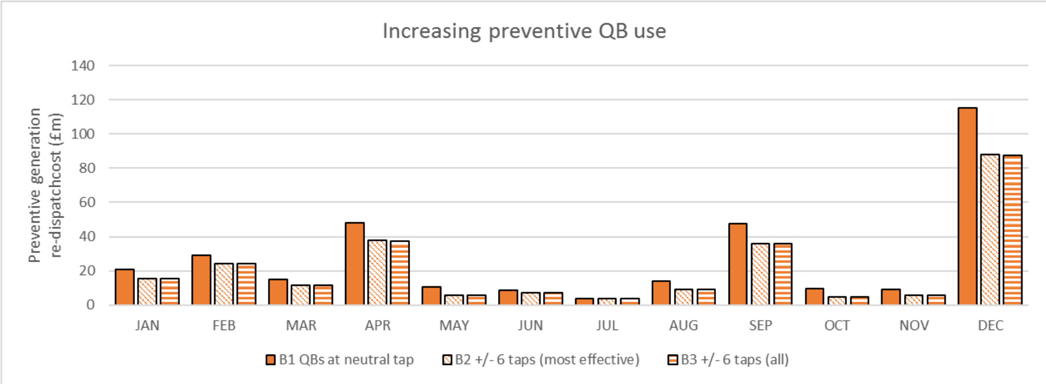

Figure 5-10: Increasing preventive QB use

Figure 5-11 shows the preventive generation re-dispatch cost of strategies B2 and B3 as a percentage of that of strategy B1 in each month (in January for instance, the cost of strategy B2 is 74.1% of that of strategy B1). It can be seen that, although the percentage improvement is substantial in some off peak months (as for instance May or October where the percentage improvement exceeds 40%) the actual monetary improvement is less than that of most other months. In December, September or April where using strategies B2 or B3 result to the highest monetary improvement the average improvement is about 25%. Further, the average improvement over the winter months is about 23%.

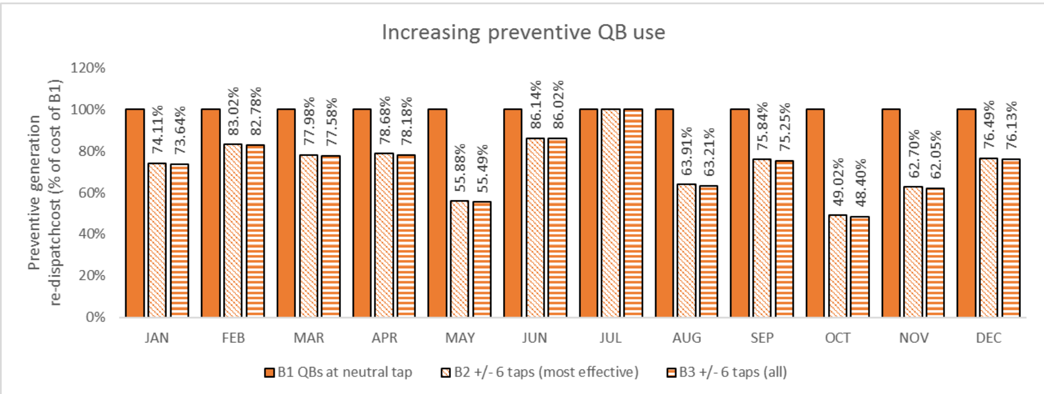

Figure 5-11: Increasing preventive QB use – percental change

In the following we focus in December. Figure 5-12 shows the reduction of wind power re-dispatch necessary to secure the network in strategy B2 (when compared to B1) in each dispatch period[130] of December against the number of QB tap pairs or devices used (tapped away from neutral tap). A reduction of up to 600 MW of wind is possible in some dispatch

130 Only dispatch periods where a branch would overload after a fault are displayed. In dispatch periods when wind curtailment reduction is zero, constraint cost saving result from the reduction of the curtailment of other generation types. Dispatch periods in ELSI are numbered consecutively starting from the 1st of January. Four dispatch periods are used per day (Appendix E: Study setup).

periods when 4 devices/pairs are used. In dispatch periods when there is no improvement in the wind curtailment metric, preventive generation re-dispatch savings can still occur from reduction of Bid or Offer acceptances of other generation types.

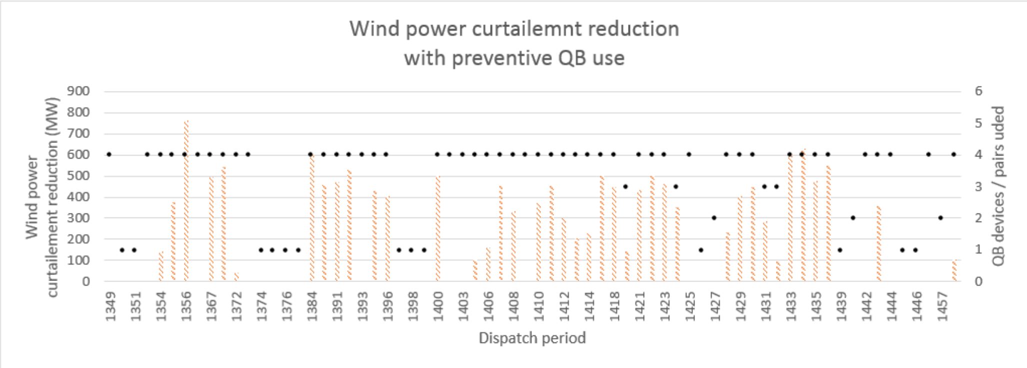

Figure 5-12: Wind power curtailment reduction of strategy B2 plotted agains number of QB devices used

Figure 5-13 shows which QBs the optimiser makes use of in strategies B2 and B3 and how often each device or pair of is used. In strategy B2, the ‘most effective’ criterion limits the optimiser to the PEWO, DEES and KEAD QBs #1 pairs as well as STSB single QB device in all dispatch periods.

From them, the PEWO QBs must be used in all dispatch periods and the DEES QBs (also on the “west” group – section 5.1.1) must be used quite often in both strategies. This is indicative of the presence of the network constraints in that area and, indeed, by comparing the location of the prevailing network constraints (Figure 5-4) and that of the most frequently used QBs (Figure 5-13), it can be seen how the placement of PEWO and DEES QBs allows them to have a greater impact on the flow through most of the network constraints.

Note however that, in strategy B2, one of the two QB pairs on the “east group” of the network (KEAD QBs #1) and the “central” QB (STSB) also need to be used (together with the PEWO and DEES QB) often[131] to achieve the best possible reduction in constraint cost. This shows that the coordination of QB devices in different areas of the network is necessary.

131 In the dispatch periods when 4 QB pairs are used, the “fourth” one is almost always the KEAD QBs # 2 pair.

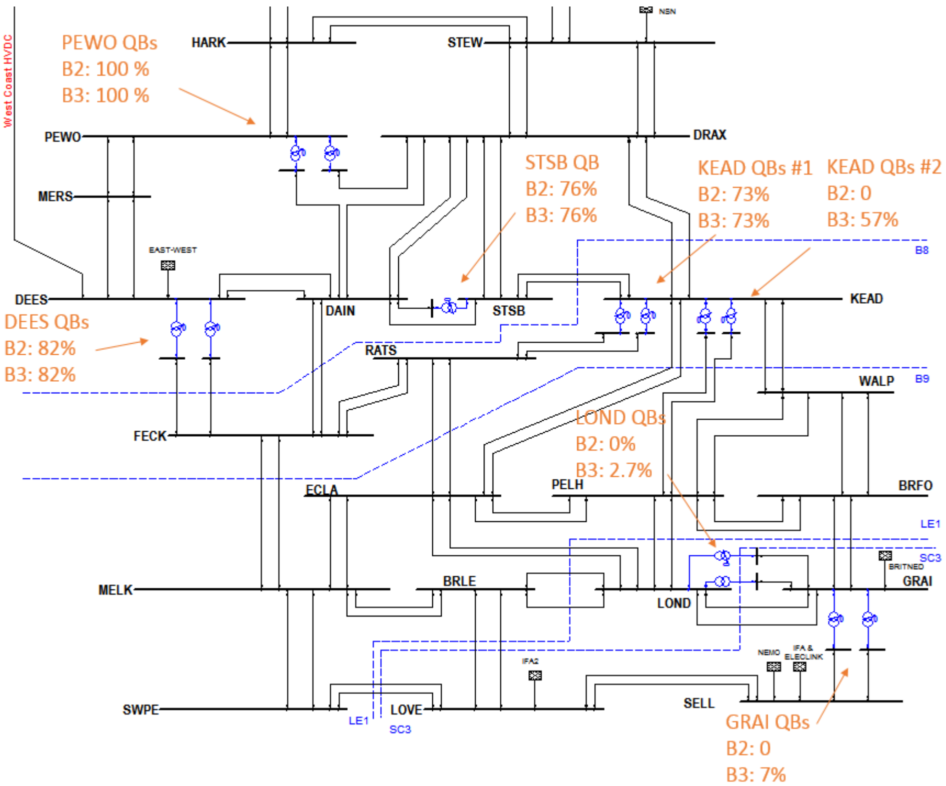

Figure 5-13: Frequncy of use of QBs in strategies B1 and B2 as a percentage of the dispatch periods that require preventive actions

We now focus on strategy B3 where the ‘most effective’ criterion does not apply and all QB devices are available to the optimiser. Due to the way the OPF method works, it does make use of most of them most of the time. In certain dispatch periods, it even uses QBs located in the south coast (GRAI and LOND QB pairs).

From an economic and network planning perspective, the additional reduction in constraint cost is marginal. The amount of MW saving[132] is below the level of accuracy of either long term or short term planning processes[133]. Based on that, it can be said that the applied process to limit the QB devices used to the ‘most effective’ ones meets its purpose.

5.3.3.2 Extent of use of QBs for corrective actions

In this section, we will use data from **strategies B1, C1 and D1** where QBs are not used for preventive actions (kept neutral tap) but the extent of use of QBs for corrective actions gradually increases (kept at pre-fault tap, single pair used, multiple pairs used respectively –

132 In the dispatch periods of December that strategy B3 offers additional benefit to strategy B2 the reduction in the amount of power that needs to Bid off is on average about 10 MW.

133 Short term planning processes are subject to the forecast accuracy. Small changes in weather impact renewable resource output and demand. Managing uncertainty at a larger scale is an inherent aspect of long term planning.

Figure 5-14). As before, the use of BMUs for preventive and corrective actions is consistent across the three strategies to allow for comparison.

Using a single pair of QBs post-fault, together with corrective control actions from BMUs, offers a clear advantage in some of the months, with the biggest difference in December. Allowing each Post-contingency OPF problem to make use of multiple pairs if required – in this strategy comparison where QBs are not used for preventive actions – offers a limited amount of additional reduction in constraint cost only - coming from certain dispatch periods of April or December and caused by specific contingency cases.

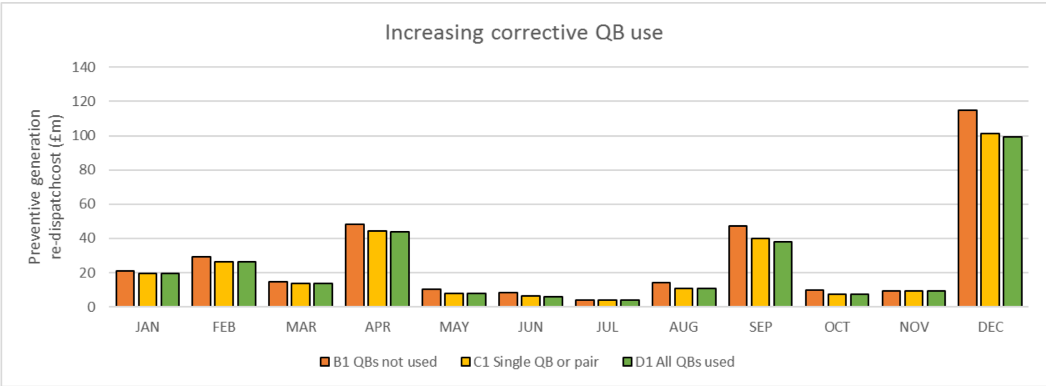

Figure 5-14: Increasing the corrective use of QBs

We now focus again in December. Figure 5-15 shows how often, among the dispatch periods of December that require preventive or corrective actions, each contingency case[134] needs to be secured to the continuous rating (red area of each contingency/column), the short-term rating (orange area), or to no rating if there is not a need to be secured at all (green area). Of course this metric is not, by itself, the decisive factor for the preventive constraint cost. Contingencies do not cause an equal amount of overload and not all of them would produce 'active' OPF constraints if included in the P-SCOPF.

However, it can be observed in Figure 5-15 that, by increasing the corrective use (using strategy C1 instead of B1 or D1 instead of C1), for most of the contingency cases, the red areas (continuous rating) will reduce in favour of the orange ones (short-term rating) or the orange ones will reduce in favour of the green ones (not secured with preventive actions). This shows that when less restrictive or fewer OPF constraints are added to the P-SCOPF problem that is generally expected to result to more economical solutions.

134 Only contingency cases that produce overloads are shown.

Figure 5-15: How the increase in corrective use of QBs changes how contingency cases are secured with preventive actions

The mechanism by which using a single pair (instead of no pairs) or multiple pairs (instead of a single pair) for corrective actions contributes towards reducing the preventive cost, is the same in both cases. Contingency cases that would be "infeasible" in the Post-contingency OPF (step A5 – Figure 4-7 or step B8 – Figure 4-8) can now be secured with corrective actions fully or partially. This determines if they are included in the P-SCOPF problem and what rating they are secured to (see sections 4.3.3 and 4.3.4).

An infeasible Post-contingency OPF problem (Table 4-1) in this application is, to some extent, the result of restrictions in the use of other active power controls for corrective actions (as explained in section 3.1.4). From an engineering perspective, if there was unlimited ability to utilise the BMUs post-fault (no limits on the number of BMU control actions or the volume of power that can be bid off or offered on), every post-contingency overload would be "correctable". Re-dispatching a certain volume of generation, coming from the BMUs that had "created" the flows that caused the overload, would be enough to mitigate it. With restrictions on the corrective use of BMUs in place, the ability of QBs to redirect the flows post-fault limits the volume of megawatts or the number BMU actions that need to be used to reduce the flow through the overloaded circuits.

As an example, we can use data from the dispatch period #1408 ("night through" – 17th of December). During that period, the unrestricted flows through the onshore circuits crossing the Scotland to England boundary of the test system sum to 6.5 GW[135]. Using strategy C1 or D1 instead of B1 results in having to constrain less generation (in each hour of the dispatch period slot). The calculated saving in constraint cost is £1.25m in the first case and £1.49m in the second (Table 5-2).

Table 5-2: Constraint cost and bid off power savings of strategies C1 and D1 when compared to strategy B1

QB use for corrective actions	Power constrained difference (MW)	Preventive generation re-dispatch cost difference (£m)
C1 - Single pair	287	£1.25m
D1 - Multiple pairs	342	£1.49m

Data from the detailed output of the QB coordination framework[136] show that four contingencies must be secured to the continuous rating (secured with preventive actions only) in strategy B1 where QBs are not used for corrective actions. Having a single QB or pair available for corrective actions (strategy C1) two of these contingencies (60042 and 60056) can be secured to the short-term rating instead (secured with preventive and corrective actions). Having all QBs available for corrective actions (strategy D1) enables one more contingency (60151) to be secured to the short-term instead of the continuous rating (Table 5-3[137]). Three of these four contingencies[138] end up producing 'active' OPF constraints at the respective P-SCOPF solutions so the rating used for their overloaded circuits impacts the P-SCOPF solution.

135 This is an overnight period, where the overall network demand is low. But due to the high wind resource at that time of the year and the low demand in the northern parts of the test network, the north-to-south flows through these areas are very high.
136 It can be found in Appendix G: Detailed results
137 Note that a number of other contingencies (not displayed) need to be secured to the short-term rating in all three strategies. They are not included in the table for brevity and because there is no change in the rating they are secured to in any of the strategies and they do not produce constraints that are 'active' at the optimal solution.
138 In more detail: 60042 and 60151 produce active constraint in the P-SCOPF solution of strategy B1; 60042, 60151 and 60042 do so in the P-SCOPF solutions of strategies C1 and D1.

Table 5-3: Contingencies of dispatch period 1408 secured to the continuos or the short-term rating in each strategy

QB use for corrective actions	Secured to continuous rating	Secured to short-term rating
B1 - Not used	60004 – PEWO4_Q1-DAIN4-PEWO4_Q2-DRAX4 60042 – ECCL4-STEW4-ECCL4-STEW4 60151 – STEW4-DRAX4-STEW4-DRAX4 60056 – PEWO4_Q2-DRAX4	
C1 - Single pair	60004 – PEWO4_Q1-DAIN4-PEWO4_Q2-DRAX4 60151 – STEW4-DRAX4-STEW4-DRAX4	60042 – ECCL4-STEW4-ECCL4-STEW4 60056 – PEWO4_Q2-DRAX4
D1 - Multiple pairs	60004 – PEWO4_Q1-DAIN4-PEWO4_Q2-DRAX4	60042 – ECCL4-STEW4-ECCL4-STEW4 60056 – PEWO4_Q2-DRAX4 60151 – STEW4-DRAX4-STEW4-DRAX4

As all four contingencies produce overloads that exceed the short-term rating, an attempt is made to secure them to the short-term rating first in all strategies. At the updated operating point (step B4 – Figure 4-8) the Post-contingency OPFs for these contingencies in strategy B1 are not feasible so, in the next iteration of the framework, they are secured to the more restrictive continuous rating.

In strategy C1 instead, the use of PEWO QBs enables the Post-contingency OPFs to be feasible for two of them (60056 and 60042 – Table 5-3). It is worth noting that PEWO QBs needs to be tapped towards a different direction in each of these two contingencies according to the solution of the respective Post-Contingency OPFs. In the case of 60056, PEWO QBs are tapped to a higher tap setting "blocking" power through the overloaded branch (PEWO4_Q2-DRAX4) that is downstream on the direction of flow from the QBs. In the case of 60042, the overloaded branch (STEW4-HARK4 circuit 1) is upstream on the direction of flow so the QBs are tapped towards a lower tap setting. That reduces their effective impedance effectively "pulling" power away from the overloaded branch and towards branches of higher capacity. In practice, the control room engineer would have to manually increase the tap settings of the PEWO QBs – relative to the pre-fault tap[139] –in the event of the first contingency and to decrease it in the event of the second to match the corrective tap settings of the respective Post-Contingency OPF solutions. This is a good example of how QBs can provide flexibility in managing post-fault flows under multiple operating conditions and contingency events.

In strategy D1 contingency 60151 can also be secured to the short-term rating. To achieve that the Post-Contingency OPF makes use of three QB pairs and one single device for corrective actions (the PEWO, DEES and KEAD # 1 pairs and the STSB single QB). The reason that so

139 In the case of the B1/C1/D1 strategies of the example, the pre-fault tap is the neutral tap. Generally, it is the tap provided by the P-SCOPF solution

many QB devices have to be used, more than the restrictions regarding the use other active power flow controls discussed earlier, is that the overload that contingency 60151 results in is higher than in the cases discussed previously and also the overloaded branch is in a more meshed area of the network. The latter means that a single QB device/pair is not enough to remove the overload anymore as the effect of its control actions is “shared” between more branches and coordinated use of multiple devices in necessary. Detailed output of the QB coordination framework for the example presented above can be found in Appendix G: Detailed results. There it can be seen the type and location of the generators that the optimiser is using for preventive action.

Using multiple devices for corrective actions increases the complexity of the action plan and the risk that the consequences of the contingency may not be removed in time but it does result in some reduction in the preventive generation re-dispatch cost. The QB coordination framework can be used to quantify the trade-off between the increase in complexity and risk and the decrease in constraint cost.

5.3.3.3 Increasing both preventive and corrective QB use

In this section we will show how increasing both the preventive and corrective use of QBs can achieve the best overall constraint cost reduction (D3 – in Figure 5-7). Data from strategies B1, C2 and D3 are used. Each differs from the previous one in that it increases the extent of both preventive and corrective use. Figure 5-16 presents the monthly breakdown of the cost for the three strategies.

It can be seen that the savings in constraint cost when using C2 instead of B1 are spread across several months with the most significant reduction taking place in December. In most months, the savings of using D3 instead of C2 are limited with the highest reductions taking place in September and in December. Overall the savings from using C2 instead of B1 (about £99m) are much higher than that of using D3 instead of C2 (about £20m).

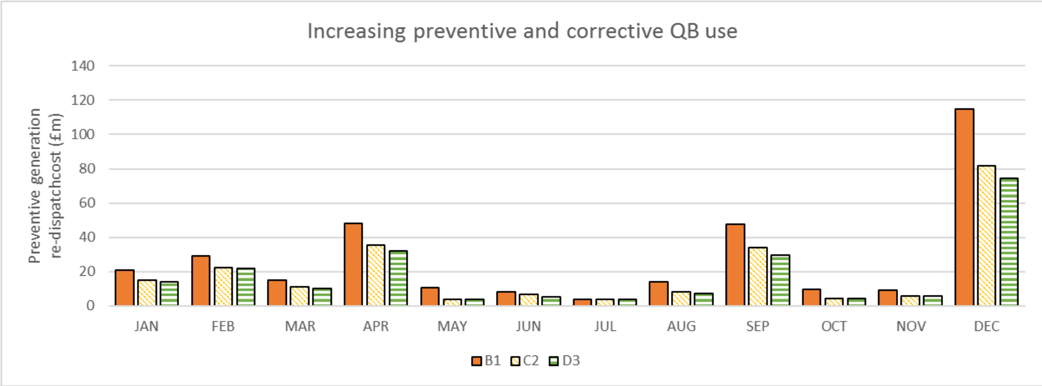

Figure 5-16: Increasing both preventive and corrective use of QBs

The two mechanisms by which increasing the preventive or corrective use of QBs affect the preventive generation re-dispatch cost, explained earlier, interact in network operation. This is captured in the workings of the iterative framework. Having more QBs available for preventive actions changes the pre-fault operating point of each trial P-SCOPF solution/iteration and affects the results of the subsequent contingency analysis which will determine which additional contingency cases will need to be considered for possible inclusion in the next iteration. Having more QB devices available for corrective actions, effects which contingency cases would need to be considered for preventive actions in the first place.

The above effects are combined in a non-separable way so the cumulative reduction of increasing both preventive and corrective use is higher than that of increasing each aspect individually. At the same time, an upper limit is reached to what can be achieved with operational measures and making more flexible use of the existing network capacity through active power control. To achieve a further reduction, investment in transmission capacity is necessary.

6 Conclusions and further work

Quadrature booster transformers can control the active power flow of the circuits they are installed in series with and, through that, exercise influence over the power flow of circuits in other parts of the network. QBs are able to redirect power flows away from a circuit that has exceeded its rating after a transmission fault or improve the sharing of flows between the circuits that cross a transmission boundary.

Through these two mechanisms, they are able to increase the transmission transfer capacity of a boundary – the power that can be securely transferred out of it or into it before there is a need for renewable or other high merit/low cost generation to be constrained off somewhere on the system. That way they could allow for a more economic operation of the network. That becomes particularly important due to the increased power flows experienced in the previous year in the GB transmission system that are expected to continue to grow in the near future as more renewable and low carbon generation will connect to the networks.

It is reasonable to expect that the benefit from the use of QBs would be greater if multiple QB devices (in multiple locations) are used for the above functions and if devices are used in a "coordinated" way. It has been shown in the past that you would need to use devices in more than one areas of the network to increase the transmission transfer capacity of some of the wider boundaries (that have multiple sets of circuits crossing them) to an even higher level [3][140].

Coordination is multi-perspective issue. The tap settings of every device have to be coordinated with the actions planned with other types of active power controls (such as generators and interconnectors) and between the preventive and corrective actions planned for the same QB. Further, coordination of the tap settings of multiple devices is necessary to avoid unwanted interactions between system areas/boundaries. A set of preventive tap-settings that maximises the transmission transfer capacity of one area/boundary of the system, for instance, is not guaranteed to also be optimal for another boundary or, even, to not make it worst.

The optimal power flow method has found many uses in the past. However, it is used less frequently in the context of operational planning and operation where SO engineers have to prepare a set of actions for the control room, some to be applied at present time and others that would need to applied after one of a set of credible contingencies. Several deficiencies of the

140 Higher than what would be possible with the use of QBs in a single location or no QB use at all. Note that the exact results of that reference apply to an older evolution of the GB network however the principle remains the same.

‘default’ OPF method have been highlighted by researchers and power system practitioners and attempts have been made to address them.

It was argued in Chapter 2 that in certain cases a more targeted approach could be necessary when designing a framework or process based around OPF or mathematical programming optimisation methods. An approach that tries to solve the problem at hand and provide part of the overall answer (to the operational planning and operation question) that can be readily used as part of the broader decision making process of the SOs, for instance, rather than an approach that tries to provide a holistic answer that covers every aspect of the problem [141] .

An example of the above argument is the use of a “direct” corrective SC-OPF model – that includes constraints and controls of both the base case and of a number of contingency cases in the same model – or of a model that prices both active power and reactive power controls in its objective function. In the first case, decisions for “present time” preventive operation would be influenced (as the optimiser is trying to find the solution with the minimum objective cost overall) by actions that are relevant to the post-fault states that the system may find itself in. In the second case, reactive power controls would be used in the OPF solution, in a non-separable way, to partly influence active power flows. If controls of the post-contingency states or the reactive power controls are not priced in the objective at all, the chosen solution might be arbitrary with regards to those controls.

Further, the operational objectives (or otherwise what the SO engineers are trying to achieve) are different during preventive and corrective operation. As discussed in Chapter 4, during preventive operation the objective should be to minimise the preventive generation[142] re-dispatch cost, while ensuring the secure operation of the system. The latter means that in the case of any of a number of pre-specified events certain consequences are avoided. The preventive generation re-dispatch cost is the only component of the cost that is definitely incurred.

When preparing for corrective, post-fault, operation, the primary objective is to have a plan of actions ready that is compatible with the operational practice and processes of the SOs[143]. The latter two are derived from (or are in-line with) the security standards that apply and they also reflect the communication and control capabilities of the power flow control devices and other active power control methods and the acceptable level of ‘risk’ regarding the application of

141 Let’s not forget that the optimal power flow is based on steady stare analysis. Other type of studies (dynamic studies or operability assessment) are also necessary when preparing for operation.
142 In this context “generation” also means interconnector and any other market participants that have to be compensated to change their output.
143 Generators are compensated for corrective actions, however, as it was explained in previous chapters that cost is only incurred if the contingency actually happens.

corrective control. Overall, the above two operational objectives combined ensure that the system is operated with as a good a level of economy as possible while maintaining a pre-defined level of security (and, resulting from that, level of reliability).

The above two operational objectives also favour the decomposition of the overall coordination of QB tap settings problem into two components: one that decides the preventive tap settings in coordination with the other active power controls and one that calculates the tap settings when QBs are used for corrective actions after a transmission fault.

Operating with corrective security takes into account the ability of the system to withstand the consequences of a transmission fault for a short period of time and that of the SO engineers to apply appropriate corrective actions that remove the consequences before that times elapses. It makes use of the short-term thermal ratings of the transmission branches that provide an additional "headroom" above the more restrictive continuous rating. Operating using the short-term ratings – securing contingency cases with corrective actions or with a combination of preventive and corrective actions – is expected to result in lower preventive generation re-dispatch than what would be otherwise required.

The iterative QB coordination framework developed in Chapter 4 consists of a preventive SC-OPF step, a process that checks if the criteria for operating with corrective security apply for each contingency case at a given operating point (and provides a plan of corrective actions for each contingency if they do) and a contingency and rating selection step. The active power controls considered are the QBs, generators, interconnectors and embedded HVDC links.

The objective of the preventive SC-OPF step is to minimise the preventive generation re-dispatch cost (constraint cost). It is able to provide a solution that includes only the 'most effective' controls using the method developed in Chapter 3. The criteria checking process makes use of contingency analysis and a single state post-contingency OPF model. The latter is able to provide a solution that limits the number of control actuations in a way that reflects SO processes regarding the corrective use of QBs and the limited time for corrective actions. The contingency and rating selection step includes the logic that decides which contingency cases should be secured with preventive actions and what the rating used for each (short-term or continuous) should be. Since the overall objective is to achieve a minimum cost operation, the framework selects only the necessary cases to be included in the P-SCOPF and tries to secure them to as high a rating as possible.

A study was setup in Chapter 5 to help draw conclusions regarding the use of the QBs through the coordination framework. It makes use of an economic (market) dispatch tool, a test model that preserves some of the main characteristics of the GB transmission network and a set of strategies regarding the preventive and corrective use of active power controls. The QB coordination framework enforces the secure operation of the network in each snapshot where the generation and demand dispatch is initially determined by the market.

The strategies examine alternative operational objectives. The two key parameters considered are the extent of use of QBs for preventive and corrective actions – both in isolation and when combined. Each strategy achieves a different level of economy and ‘complexity’ of operation while maintaining the same, pre-defined, level of security. The settings of the strategies range from not using QBs for preventive or corrective actions, to the baseline strategy of using the ‘most effective’ QBs only for preventive actions and devices of a single location for corrective actions to, finally, having available devices in all locations for preventive or corrective actions on the other extreme (Figure 5-7)

The QB coordination framework was applied in the dispatch periods of a (simulated) calendar year. That way the preventive generation re-dispatch cost of each strategy is evaluated over an extended period of time and varying conditions. The detailed output of the framework provides additional insights such as how the specific QBs and generators are utilised by the mathematical programming optimiser and what the ‘active’ network branch constraints are.

It was found that, if only one of two aspects (preventive or corrective operation) could be improved (from the no QB use scenario), it is the preventive use that is, by itself, able to achieve the highest overall reduction in constraint cost. This can be understood because using QBs to re-distribute and direct flows away from the components of lower capacity of the network (“weak” links) can directly influence the extent that generators have to be used to reduce the flow through the same components. Having all QBs available instead of using the ‘most effective’ criterion provides only a limited additional reduction in constraint cost.

The optimiser is using multiple QBs of the test network in coordination to achieve the best possible outcome. The QBs of the “west”, “central” and “east” group are used together to “block” or “pull” power across the circuits they are installed in series with and redistribute the flows across the circuits of a wider area of the network. When the ‘most effective’ criterion is applied, only one of the two QB pairs of the “east” group is used (in addition to the “west” and “central” QBs). When it is not, the optimiser makes use of the second QB pair of the “east” group often and, in certain dispatch periods, even of the QBs of the “south coast” group. The latter two are located areas of the network distant from to the prevailing network constraints and would not be normally considered by the SO engineers.

Having started using QBs for preventive actions, increasing the extent of use for corrective actions can contribute to a further decrease in constraint cost to the degree that it allows certain contingency cases to be secured with corrective actions only or, if preventive actions are also required, to a higher thermal rating (short-term instead of continuous rating). It is expected that, for most contingency cases and operating conditions, using the generators and other active power controls would be sufficient to remove the overload(s) caused by the contingency. The cost of the generator corrective actions will only be incurred if the contingency takes place so it does not contribute to the preventive generation re-dispatch cost.

Following the contingency there are certain restrictions to the volume or number of post-fault actions that apply. This is captured in the study setup where a maximum number of post-fault BMU (generator) instructions is enforced, the ramp-up rate of thermal generators (most commonly used to provide replacement energy) is taken into account and a limit is set to the amount of power that can be Bid off to stay within the limits of the frequency containment service. Further, in certain dispatch periods where there is high renewable output and low transmission demand, it is possible that there is not enough thermal generation synchronised in the network and ready to be used to balance the system after a contingency if a lot of power needs to be constrained in order to remove the overload.

In a similar way as in the preventive use scenario, QBs can be used post-fault to redirect flows away from the overloaded branch or re-distribute the flows across a number of circuits in a way that limits the amount of corrective generation re-dispatch required. Subject to the study setup assumptions, the use of QBs for corrective actions can circumvent the restrictions and make it possible that more contingency cases become “correctable” or secured to a higher thermal rating in the preventive SC-OPF as described previously.

Using the QBs of a single network location for corrective actions (as in the baseline strategy) was found to be sufficient for many contingency cases and dispatch snapshots. For some of the others, devices in as many as four network locations had to be used. The latter is a departure from the baseline strategy. Acting on four network locations results in the simultaneous change in flows in multiple branches (as all tap and BMU actions have to be completed by the end of the short-term rating time period). The transition from the set of initial tap settings to the final one poses a challenge in term of not creating additional overloads. This increases the ‘complexity’ of the proposed action plan and the risk that comes with its execution.

To conclude, the active and coordinated use of QBs in multiple locations for preventive actions is the single most important factor for the reduction in the preventive generation re-dispatch cost. The preventive use of QBs can directly impact the preventive generation re-dispatch cost (constraint cost) and their active use should be preferred against a strategy that aims to maximise their post-fault utilisation. Coordination of the preventive tap settings of devices in multiple locations in way that the transmission transfer capacity of the different areas of the network is utilised is as an economic way as possible can be achieved with the use of the optimal power flow method.

In addition to the above, also using QBs for corrective actions can provide a further reduction in constraint cost. Coordination between the preventive and corrective QB tap settings can be achieved through the use of the described framework. A portion of that reduction is possible with the use of devices in a single location only. To achieve the full reduction, devices of multiple locations would have to be used for specific contingencies and dispatch periods that are likely to result in action plans of increased complexity. This may bring forward the need to investigate alternative (operational) solutions for preventive or corrective constraint management to be used in these conditions and for these contingency cases.

Finally, actively using QBs for both preventive and corrective actions does offer the possibility for an important cumulative reduction in constraint cost over an extended period of time but a limit is reached with what can be achieved with the flexible use of the existing network capacity through active power control. Following that, investment in transmission network capacity may be necessary.

In summary, if all QBs are used for preventive actions (instead of the 'most effective' ones) and if QBs of multiple locations are used for corrective actions (instead of devices of a single location), the analysis showed that a 36% reduction in the preventive generation re-dispatch cost is possible over a strategy where QBs are not used at all for either preventive or corrective actions and it is the recommended strategy[144]. Further, the described strategy can result in a reduction of 8.6% over a strategy of where only the 'most effective' QBs are used for preventive actions and only QBs of a single location are used for corrective actions.

So, the novelty and contribution of this work is twofold. First, the developed framework is a comprehensive, practical and complete method for coordinating the QB tap settings and it also addresses many of the considerations of SO engineers in a way that it could be readily used to enhance existing processes. Second, it draws a clear conclusion regarding what is the best way to utilise the QB devices that is supported by bespoke analysis and data.

144 In Chapter 5, this would be either strategy D2 or D3 since they both achieve the same preventive generation re-dispatch cost figure.

6.1 Further work

One of the first areas where further work is needed is the application of the QB coordination framework in alternative study setups. They should include additional test networks or study setups where reactive power and voltage are considered in the contingency analysis at the new temporary operating point. The objective is to determine how well the framework performs and how it can scale or be ported to other applications than the one the results of Chapter 5 are based on and if any improvements or adjustment are needed to do so.

Having concluded this part of the work there are some enhancements or possible directions that future work should take. One enhancement would be to include more discrete steps in the strategies that examine the extent of use of QBs for corrective actions. Currently, the steps considered are ‘no QB use’, ‘single QB or pair’ and ‘all QBs’. Having more granularity in the between of the latter two steps (such as a ‘two QB pairs’ step) could allow the evaluation of a more granular increase in the post-fault operational complexity and the effect it may have on reducing the preventive generation re-dispatch cost. The framework can be straightforwardly extended to include that, but further analysis of the results is required.

Further, this work focuses on the use of QBs and embedded HVDC links – there are already many QBs installed in the GB network, and there is one embedded HVDC link with more planned. There is scope to extend it to include other FACTS devices such as thyristor controlled series compensation or other methods for active power controls such as topological actions [170], [171]. Although the modelling of the different FACTS devices in steady state conditions is similar, each type of device should be included in a way that respects the operational practice regarding its use and the capabilities of the control and supervision systems available.

One aspect of power system operation that has not been addressed in this work is the management of uncertainty [172] – as for instance when wind power output or demand does match the forecast – and how this can be included in an optimisation based decision making process [173], making use of potential flexibility offered by storage or demand side response [174] and of the power flow control ability of HVDC links [175] or QBs.

Similarity, the work so far has not directly addressed the use of active power flow control or QBs within a probabilistic or risk based approach for network planning, where the probability and impact of various contingencies is considered when estimating the actual system reliability [176] and optimisation models and processes consider the effect of probability and cost on the optimal mix of preventive and corrective actions [177] or when candidate transmission reinforcement options have to be considered against a large number of varying operating conditions [178].

One more area where further work is needed is that of the inclusion of offshore HVDC networks (that could be of multi-terminal or meshed configuration) into the coordination framework. Offshore HVDC networks allow multiple offshore wind farms to connect (avoiding the need for costly radial links to land) [179] [180] but they also increase transmission transfer capacity of the onshore AC network by providing additional routes that power can follow to bypass the onshore network limitations. As the HVDC networks can control the power flow through their individual components – and though that influence the power flow on the AC parts of the network [75] – coordination between the use of AC active power control devices and the control ability of the HVDC network is required to ensure the overall onshore and offshore network capacity is used as efficiently as possible [181].

Appendixes

Appendix A: QB technology

Principle of operation

Phase-shifting transformers can be considered as transformers with a complex turn ratio, able to control the phase angle difference between the voltage phasors on their input (V_s) and output (V_l) terminals. Indeed, according to IEC/IEEE guide for the application, specification and testing of phase-shifting transformers [182], an equivalent for a PST would be an ideal transformer with impedance $Z_t = 0$ that is able to introduce a no-load phase angle "a" and an additional transformer with 1:1 turns ratio and an impedance $Z_t = R_t + j\,X_t$.

Therefore, a PST has two separate effects on the flow of power. An additional voltage is created by the no-load phase angle that drives additional current through the line while at the same time additional impedance is added to the circuit that leads to a voltage drop.

The total (under load) phase-shift angle a^* that is finally introduced to the line is made up by the effect of the no-load phase angle a of the ideal transformer and the load angle that occurs within the PST because of the internal impedance Z_t.

Phase-shift angle a^* can be chosen to restrict (or "buck") the flow through the device when the output terminal voltage phasor V_l (with respect to the direction of flow) lags the input terminal voltage phasor V_s. The device is then said to operate in "retard" phase-shift angle. Respectively, a^* can be produced to advance (or "boost") the flow through the device (with respect to the original flow when $\alpha = 0$) when V_l leads V_s. The device is then said to operate in "advance" phase-shift angle.

The flow of active and reactive power over a long distance, high voltage transmission line in steady state conditions is described by the following equations [183],

$$P = \frac{(|V_s||V_r|)}{X} \sin\delta \qquad \text{Ap. 1}$$

$$Q = \frac{(|V_s||V_r|)}{X} \left(\cos\delta - \frac{|V_s|}{|V_r|}\right) \qquad \text{Ap. 2}$$

where the subscript s stands for the sending end of the transmission line, r for the receiving end, X is the reactance and δ is the load angle - the angular difference of the voltage phasors on either end - of the line.

Consequently, the phase-shift angle a^* is added up to δ to increase or decrease the flow on the line.

Types of phase-shifting transformers

There are different types of PST available, each having different structural and operational characteristics. One of the main distinguishing factors is the way the no-load phase angle is acquired.

The simplest way to acquire a no-load phase shift angle between the terminals of a single 3-phase transformer is by the appropriate connection its windings (single-core design).

A different design option is to use two different transformer units (two-core design). One of them is connected in series with the line circuit (series unit), bearing the regulated circuit where it is desirable to control the phase angle and/or voltage magnitude. The second transformer (main or shunt or parallel unit) is connected in parallel with the line circuit. It bears the excitation windings that draws energy from the source and the regulating windings where taps are changed. The main unit furnishes excitation to the series unit. So real power is extracted from the network through the parallel branch and injected back to the transmission line, by injection of a voltage, through the series branch [184].

The two-core design is more complex but it gives flexibility in selecting the characteristics of the Load Tap Changers (LTCs) -like the voltage per step, the current of the regulating winding and LTC switching capacity- and the ability to better match these characteristics with the rating of the PST and the phase angle requirements. LTCs are one of the main limiting factors for the rating and the operating range of the PST. So it is often than more than one tap changers per phase or LTCs with an “advance – retard switch” (that doubles the available taps) are used [182].

Depending on the arrangements and the electrical connections between the different windings, PSTs with different operational characteristics will occur. A common connection is depicted in Figure Ap. -1.

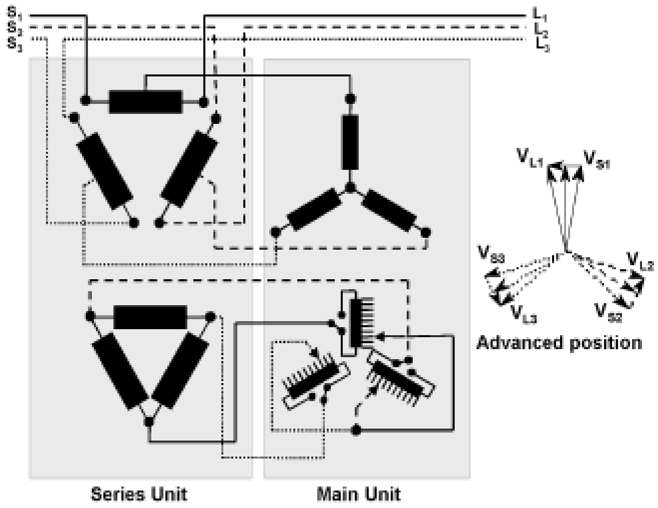

Figure Ap. -1: Common two-core PST connections. Source: [182]

A special type of PST is the Quadrature boosting transformer (QB). The main characteristic of a QB is that the injected voltage ("quadrature" voltage) is at 90˚ phase difference with respect to the line voltage and current (line voltage and current are in phase). The 90˚ phase shift is acquired at the intermediate circuit (the circuit connecting the series and the shunt unit) as a result of the different electrical connections within the series unit. In particular, series winding is not tapped from its centre (as it appears to be in Fig. 1). The design is therefore simpler than a typical PST and the HV connection between the series and shunt unit is simplified. It also allows for the better utilisation of the LTCs switching capacity [40]. The injected voltage causes a phase angle shift across the terminals of the device.

Because the injected voltage is always in quadrature with the line voltage, the magnitude of the injected voltage is the control variable [185]. The magnitude and the direction (either leading or lagging) are controlled by the tap position of the LTCs of the regulating windings. Consequently, the phase angle shift and the power flow on the line is a function of the tap position as well.

As a result, a QB transformer will produce an output terminal voltage different both in phase and in magnitude with regard to its input terminal voltage. This has a greater effect on load flow characteristics and on the voltage profile of the network than other types of PSTs. However the difference in magnitude is judged to be moderate for small phase shift angles and it can be tolerated by the power system [186].

PSTs are generally classified as "symmetrical" or "asymmetrical". An asymmetrical PST will create an output voltage with different phase angle and magnitude compared to its input voltage (without considering the effect of the impedances internal to the device). A symmetrical PST will create a voltage with a different phase angle but of the same magnitude as its input terminal voltage (again, neglecting internal PST losses) [183].

Design and performance factors

Many design and performance factors have to be specified before the procurement of a PST by a TSO. The design process usually involves consultation of the TSO with the manufacturer and the PST is constructed for the particular power system and its planned location in the network and also having in mind a range of 'planned' operational circumstances more likely to occur.

For example, considerations about shipping (size and weight limitations) might determine the type of the transformer and eventually might even limit its operational range as well [3]. Other requirements may include the ability to exchange position of the PSTs within the network.

Other design and performance factors as cited in [182] [186] [187]are:

- The continuous power rating, that has to match that of the line, and the short-term power ratings.
- The rated phase angle (under no-load conditions) and the phase-shift angle requirements (under load) towards the advance and retard directions.
- The impedance characteristics; rated impedance at zero phase-shift and the change in impedance with phase-angle regulation.
- The voltages at the different parts of the transformer as well as in the intermediate circuit. The internal voltages and fluxes may limit the operational range in "buck" mode.
- The connected system short-circuit capability.
- LTC performance characteristics (switching capability, voltage per tap under rated loading conditions and through current rating).
- LTC design; number of available taps per direction, number of LTCs per phase, use or "advance-retard" switch and/or coarse change-over selector.
- Electrical protection scheme.
- Control, supervision and protection system of the device;
- control of the tap changer,
- monitor, supervision and logging of operation parameters (core and windings temperatures, oil condition, voltages and currents and more),
- over-voltage and over-excitation protection.

Examples of the consultation and design process that took place before the procurement of PST devices as well as the laying down of the specification and the requirements for the different applications can be found in the references. In particular, the authors of [186] examine the design issues, the specifications and the requirements for the procurement of four HV and high rating (2750 MVA) QBs by National Grid Electricity Transmission (NGET). Some of the pre-commission tests that took place are also described.

Appendix B: Power system sensitivities

In this section we will show how the PTFD and QBDF sensitivity ratios are derived. It is assumed that the DC model network approximations apply.

Then the flow inserted in the 'from' side of the branch i, j is approximated by:

$$\mathrm{pf}_{\mathrm{i,j}} = \frac{\theta_{\mathrm{i}} - \theta_{\mathrm{j}}}{\mathrm{x}_{\mathrm{i,j}}} \quad (\mathrm{p.u.\,MW}) \qquad \text{Ap. 3}$$

And the sum of the active power injections from the branches connected to bus i is given by:

$$\mathrm{pbus}_{\mathrm{i}} = \sum_{\mathrm{m}\,\in\Omega} \frac{\theta_{\mathrm{ij}}}{\mathrm{x}_{\mathrm{ij}}} = \sum_{\mathrm{m}\,\in\Omega} \frac{\theta_{\mathrm{i}}}{\mathrm{x}_{\mathrm{ij}}} + \sum_{\mathrm{m}\,\in\Omega} -\frac{\theta_{\mathrm{j}}}{\mathrm{x}_{\mathrm{ij}}} \quad (\mathrm{p.u.\,MW}) \qquad \text{Ap. 4}$$

where Ω is the set of buses directly connected to bus i.

The above relations for all the branches and all the buses can be compactly written in matrix form, respectively, as:

$$\mathbf{pf} = \mathbf{Bf} * \boldsymbol{\theta} \qquad \text{Ap. 5}$$

$$\mathbf{pbus} = \mathbf{Bbus} * \boldsymbol{\theta} \qquad \text{Ap. 6}$$

Or in incremental form:

$$\mathbf{dpf} = \mathbf{Bf} * \mathbf{d}\boldsymbol{\theta} \qquad \text{Ap. 7}$$

$$\mathbf{dpbus} = \mathbf{Bbus} * \mathbf{d}\boldsymbol{\theta} \qquad \text{Ap. 8}$$

The detailed explanation of how each vector or matrix is formed is given in Table Ap. -1.

Combining (Ap. 7) and (Ap. 8) we get:

$$\mathbf{dpf = Bf * d\theta = Bf * Bbus^{-1} * dpbus} \qquad \text{Ap. 9}$$

Or:

$$\frac{\mathbf{\Delta Pf}}{\mathbf{\Delta Pbus}} = \mathbf{Bf * Bbus^{-1}} \qquad \text{Ap. 10}$$

The last equation provides the matrix of the generations shift factors for the particular network configuration.

Using the DC model approximations, a phase-shifting transformer can be modelled as an ideal transformer with complex turns ratio in-series with a reactance (Figure Ap. -2).

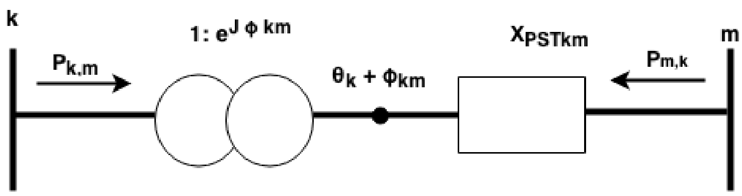

Figure Ap. -2: PST Model

Then the flow through the transformer is given by:

$$pf_{k,m} = \frac{\theta_k + \varphi_{km} - \theta_m}{x_{k,m}} \quad (\mathrm{p.u. MW}) \qquad \text{Ap. 11}$$

$pf_{k,m}$ depends on both on the natural voltage angle difference across the branch θ_{km} and the resulting phase-shift angle due to the injection of voltage by the PST, expressed through the argument of the complex turns ratio, φ_{km}. If φ_{km} is considered to be constant, the term φ_km/x_km can be represented as an extra pair of generators on buses k and m. The generator on bus k would produce $\varphi\_km/x_{\_km}$ p.u. MW and the generator of bus m would absorb an equal amount when $\varphi_{km} > 0$ or the opposite when $\varphi_{km} < 0$.

The effect of a single tap change, that introduces a phase-shift angle of φ_{km} (rad) across the terminals of PST km, to the MW flows on the 'from' side of all the branches of the network can then be calculated as:

$$\frac{\mathbf{\Delta Pf_{PSTkm}}}{\mathbf{\Delta \varphi_{km}}} = \mathbf{Bf} * (\mathbf{Bbus^{-1}} * \ \mathbf{\Delta Pbus_{km}}) - \ \mathbf{\Delta Pfinj_{km}} \qquad \text{Ap. 12}$$

Generation shift factors carry the implicit assumption that a given bus injection is compensated by an opposite and equal MW injection from the 'slack' generator [145]. However, every real world transaction takes place between two real network elements or two groups of elements as anticipated by PTDFs.

PTDFs can be calculated directly from generation shift factors due to the superposition principle [188]. For instance, the effect of the exchange of one unit of power between buses i and j to branch l is equal to the combined effect of two exchanges: the first between bus i and the slack bus and the second between bus j and the slack bus (Ap. 13). In the same way transactions between two sets of elements can be calculated.

Further, due to the same principle generation shift factors can be used in an OPF calculation to quantify the effect of bus injections to branch flows so long as the power balance is explicitly maintained.

$$\mathrm{PTDFs}_l^{i,j} = \frac{\Delta \mathrm{Pf}}{\Delta \mathrm{Pbus}}(l,i) - \frac{\Delta \mathrm{Pf}}{\Delta \mathrm{Pbus}}(l,j) \qquad \text{Ap. 13}$$

Table Ap. -1: Notation of the section

nb	Number of buses
nl	Number of branches
θi	Voltage angle of bus i (rad)
$x_{i,j}$	Reactance of the branch connecting buses i and j (p.u.) i is considered to be the 'from' and j the 'to' side of the branch
$x_{PST\ k.m}$	Series admittance of a PST transformer connected between buses k and m (p.u.)
pbus	Column vector of net bus MW injections (p.u. MW) of dimension *nb*.
$\boldsymbol{\theta}$	Column vector of bus voltage angles (rad) of dimension *nb*.
pf	Column vector of branch MW flows ('from' side) (p.u. MW) of dimension *nl*.

145 The 'slack generator' is a computational concept where the losses of the system (or in the case of a contingency any power imbalance and incremental losses as well) are assigned to a single, fictional generator. A more realistic alternative is the 'distributed slack generator' where the losses are distributed among all generators according to participation factors.

Bbus	Sparse DC model bus admittance matrix of dimensions *nb x nb* $$\mathrm{Bbus(i,j)} = \begin{cases} -\frac{1}{X_{ij}} \text{ if } i \neq j \\ \sum_{m \in \Omega} -\frac{1}{X_{im}} \text{ if } i = j \end{cases}$$ where Ω is the set of buses directly connected to bus i
Bf	Sparse DC model branch admittance matrix ('from' side) - dimensions *nl x nb.* If there is a branch connecting buses i and j $$\mathrm{Bf(i,j)} = \frac{1}{X_{ij}} \; and \; \mathrm{Bf(j,i)} = -\frac{1}{X_{ij}}$$ else $\mathrm{Bf(i,j)} = 0 \; and \; \mathrm{Bf(j,i)} = 0$
$\frac{\mathbf{\Delta Pf}}{\mathbf{\Delta Pbus}}$	Matrix of generation shift factors of dimensions nl x nb.
$\frac{\mathbf{\Delta Pf_{PSTkm}}}{\mathbf{\Delta \varphi_{km}}}$	Column vector of ΔFlow/ΔTap sensitivity ratios of dimension *nl.* $\frac{\Delta Pf_{PSTkm}}{\Delta \varphi_{km}}(i)$ quantifies the variation in 'from' MW flow across branch i due to a tap change of PST *km* that results to an additional phase-shift of φ_km across the branch *km*.
$\mathbf{\Delta Pbus_{km}}$	Sparse column vector of dimension *nb*. It contains the equivalent 'from' and 'to' side MW injections that model the effect of a tap change of PST km. $$\Delta \mathrm{Pbus_{km}}(i) = \begin{cases} \frac{\varphi_{km}}{X_{km}} \quad \text{if } i = k \\ -\frac{\varphi_{km}}{X_{km}} \quad \text{if } i = m \end{cases}$$
$\mathbf{\Delta Pfinj_{km}}$	Sparse column vector of dimension *nl*. It contains the equivalent 'from' side MW injection through branch *km* that models the effect of a tap change of PST km. $$\mathrm{Pfinj_{km}}(i) = \frac{\varphi_{km}}{X_{km}} \quad if\ i\ is\ the\ index\ of\ branch\ km\ in\ vector\ \mathrm{Pf}$$

Appendix C: Sparse OPF model

Model Ap. -1 is an alternative OPF model formulation that can be used to find the optimal settings of active power controls. Its main differences with Model 3-3 are:

- It uses a quadratic objective instead of a linear objective function.

- It uses sparse formulation for the equality and inequality constraints. The DC power flow equations for establishing the active power injection balance of the buses and for calculating power flow across the braches are embedded in the model in the equality constraint and inequality constraints respectively
- The objective variable is the phase shift angle of the QBs (**shift)** instead of tap

$$\min_{\Theta, \mathrm{pg}, \mathrm{shift}} [\boldsymbol{\Theta}\ \mathbf{pg}\ \mathbf{shift}]^{\mathrm{T}} * \mathbf{H} * [\boldsymbol{\Theta}\ \mathbf{pg}\ \mathbf{shift}] \quad \text{Ap. 14}$$

s.t. $$\mathbf{Bbus} * \boldsymbol{\Theta} - \mathbf{Cg} * \mathbf{pg} + \mathbf{Bbusqb} * \mathbf{shift} - \mathbf{pd} = \mathbf{0} \quad \text{Ap. 15}$$

$$\mathbf{Bf} * \boldsymbol{\Theta} + \mathbf{Bfqb} * \mathbf{shift} \leq \mathbf{fmax} \quad \text{Ap. 16}$$

$$-\mathbf{Bf} * \boldsymbol{\Theta} - \mathbf{Bfqb} * \mathbf{shift} \leq -\mathbf{fmax} \quad \text{Ap. 17}$$

$$\theta_{\mathrm{i}}^{\mathrm{ref}} = 0 \qquad \mathrm{i} \in \mathrm{I}_{\mathrm{ref}} \quad \text{Ap. 18}$$

$$\mathbf{pg}_{\mathbf{min}} \leq \mathbf{pg} \leq \mathbf{pg}_{\mathbf{max}} \quad \text{Ap. 19}$$

$$\mathbf{shift}_{\mathbf{min}} \leq \mathbf{shift} \leq \mathbf{shift}_{\mathbf{max}} \quad \text{Ap. 20}$$

Model Ap. -1: Sparse formulation single state OPF model

Appendix D: Test network data

Background

The test network is based on the "Representative GB Network Model" [162], [163] that was developed at the University of Strathclyde by the author with the support of the EPSRC "Supegen Flexnet" (EP/E04011X/1) program [189]. The representative model is a simplified, scaled down version of the actual GB transmission system and it is configured and validated against a solved AC power flow study that was provided by National Grid[146] [190].

The test system used in this thesis is an updated version of the Representative GB Network Model that includes changes in the GB system since the original model was developed. Only publicly available sources such as the Electricity Ten Year Statement (ETYS), the Electricity Scenario Illustrator (ELSI) model [191] and the Interconnector Register [192] were used for the update.

146 That study dispatched the available generation and interconnectors according to the SQSS 'Economy Criterion' to meet the winter 2009/10 Average Cold Spell (peak) demand.

The Representative GB Network Model, in its original form or in a custom version, has been used over the years in various BSc or MEng student projects. It has also been used in a number of research publications within and beyond the "Flexnet" consortium.

In the test network (Figure Ap. -3), the Scottish Hydro Electric Transmission (SHET) TO area (north Scotland) is modelled by the nodes and branches "north" of boundary B4. That of Scottish Power Transmission (SPT) TO (central and south Scotland) by the area between boundaries B4 and B6. The National Grid Electricity Transmission (NGET) TO area (England and Wales) is "south" of the boundary B6.

In Figure Ap. -4 the test model nodes are overlaid on the one-line diagram of the GB system. The generation capacity and demand of each of the GB system buses has been aggregated into the test model nodes. The transfer capacity between the buses has been captured in the lines connecting the nodes in the model.

In order to capture some of the characteristics of the actual GB system the test model nodes are chosen, to the extent possible, so that they:

- Enclose an area with high concertation of generation or demand, or
- Are connected by branches of lower capacity or branches that are expected to become the limiting factor for transferring power across the different areas after a network fault.

The test system should not be used to draw conclusions about the technical or economic performance of the actual GB system. It should be used as a benchmarking tool and for the early development and comparison of concepts.

Network diagrams

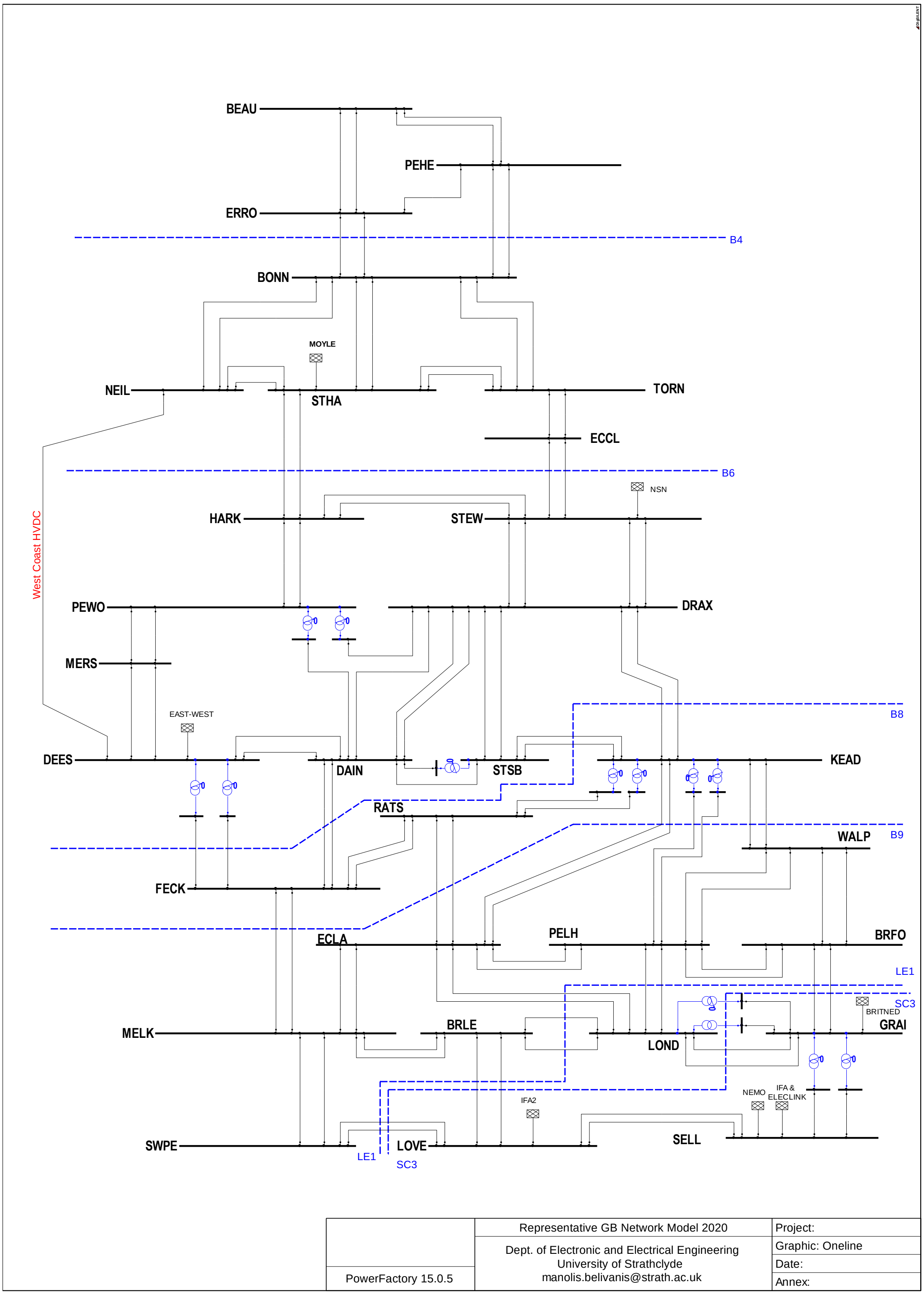

Figure Ap. -3: Test network oneline diagram

This Figure has been removed by the author for copyright reasons. The background image can be found in Appenix A (Figure A4) of referece [193].

Figure Ap. -4: Test model nodes and boundaries overlaid on the GB transmission network one-line diagram. Background source: [193]

Detailed network data

The following tables present the data of the test model in detail.

Bus data:

- The active (PD) and reactive (QD) power demand values have been aggregated from the solved AC power flow study [190]. They correspond to the winter 2009/10 Average Cold Spell demand.
- The shunt susceptance (BS) values are provided in MVAr at 1.0 pu bus voltage. They model reactive power injection coming from shunt elements such as shunt capacitors and reactors but also: a) the line charging susceptance of the branches and cables encircled in each test model node and b) the LV shunt gain of the distribution network fed from the transmission system Grid Supply Points. The reported values have been aggregated from the solved AC power flow study [190].
- All three (PD QD and BS) should be adjusted by the user depending on the application.

Table Ap. -2: Bus data

FnKey	Node	Flop	kV	TO	PD (MW)	QD (MVAr)	BS (MVAr)
10001	BEAU4	T	400	SHET	490	242.5	121.25
10002	PEHE4	T	400	SHET	543	420	210
10003	ERRO4	T	400	SHET	599	263.4	131.7
10004	BONN4	S	400	SPT	1327.3	923.5	461.75
10005	NEIL4	S	400	SPT	505.8	260.2	130.1
10006	STHA4	S	400	SPT	1203.4	827.7	413.85
10007	TORN4	S	400	SPT	753	496.9	248.45
10008	ECCL4	S	400	NGET	118.5	44.1	22.05

10009	HARK4	Q	400	NGET	134.9	192.4	96.2
10010	STEW4	Q	400	NGET	2569	1225	612.5
10011	PEWO4	R	400	NGET	717.8	530.4	265
10012	DEES4	M	400	NGET	1209	1112	556
10013	DAIN4	N	400	NGET	2545	1498.5	749.25
10014	STSB4	P	400	NGET	1843.5	1065.7	532.85
10015	DRAX4	P	400	NGET	2669	1902.4	951.2
10016	KEAD4	P	400	NGET	1851.5	3389.6	1694.8
10017	RATS4	L	400	NGET	895.5	942.1	471.05
10018	FECK4	L	400	NGET	4351.5	3381	1833.5
10019	WALP4	J	400	NGET	930	1460	870.5
10020	BRFO4	J	400	NGET	1942	1059	394.4
10021	PELH4	D	400	NGET	1219	1000	424.1
10022	ECLA4	D	400	NGET	1861.8	1498.1	749.05
10023	MELK4	H	400	NGET	4781.4	3185.8	1592.9
10024	BRLE4	B	400	NGET	1423.9	894.7	447.35
10025	LOND4	A	400	NGET	10504	5569.7	2784.85
10026	GRAI4	C	400	NGET	1025	1287	713
10027	SELL4	C	400	NGET	462.8	359.7	179.85
10028	LOVE4	B	400	NGET	2762	1242.7	621.35
10029	SWPE4	F	400	NGET	2602	923.7	461.85
10030	MERS4	N	400	NGET	2236.2	1652.3	826.35
10031	PEWO4_Q1	R	400	NGET	0	0	0
10034	PEWO4_Q2	R	400	NGET	0	0	0
10035	DEES4_Q1	M	400	NGET	0	0	0
10036	DEES4_Q2	M	400	NGET	0	0	0
10037	STSB4_Q1	P	400	NGET	0	0	0
10038	KEAD4_Q1	P	400	NGET	0	0	0

10039	KEAD4_Q2	P	400	NGET	0	0	0
10040	KEAD4_Q3	P	400	NGET	0	0	0
10045	KEAD4_Q4	P	400	NGET	0	0	0
10046	LOND4_Q1	A	400	NGET	0	0	0
10047	LOND4_Q2	A	400	NGET	0	0	0
10048	GRAI4_Q1	C	400	NGET	0	0	0
10049	GRAI4_Q2	C	400	NGET	0	0	0

Branch data:

The resistance (R), reactance (X) and susceptance (B) values are provided in pu on a 100 MVA base. The rating (RATE_A) is the winter continuous thermal rating of the branch.

Table Ap. -3: Branch data (OHL)

FnKey	Node1	Node2	BR_R (pu)	BR_X (pu)	BR_B (pu)	RATE_A (MVA)
20001	STEW4	DRAX4	0.00052	0.0063	1.0636	2000
20002	STEW4	DRAX4	0.00052	0.0063	1.0636	2000
20003	STEW4	HARK4	0.00492	0.0343	0.2502	775
20004	STEW4	HARK4	0.00352	0.02453	0.1898	855
20005	MERS4	DEES4	0.0001	0.0085	0.0798	3320
20006	MERS4	DEES4	0.0001	0.0085	0.0798	3320
20007	PEWO4_Q1	DAIN4	0.0004	0.003	0.2664	2420
20008	PEWO4_Q2	DRAX4	0.0004	0.003	0.2498	2420
20009	DAIN4	DRAX4	0.0004	0.003	0.2498	2420
20010	DEES4_Q1	FECK4	0.00097	0.0053	0.3835	2400
20011	DEES4_Q2	FECK4	0.00074	0.0053	0.2911	2400
20012	DAIN4	DEES4	0.00096	0.01078	0.385	3100
20013	DAIN4	DEES4	0.00096	0.01078	0.385	3100
20014	DAIN4	STSB4	0.00082	0.01201	1.2125	1330
20015	DAIN4	STSB4_Q1	0.00107	0.00793	1.1745	1649
20016	DAIN4	FECK4	0.00084	0.007	0.7759	2170
20017	DAIN4	FECK4	0.00049	0.007	0.1943	2170

20018	DRAX4	DAIN4	0.00164	0.023	0.1104	955
20019	DRAX4	DAIN4	0.00137	0.023	0.6643	1240
20020	DRAX4	STSB4	0.00018	0.0012	0.5573	2700
20021	DRAX4	STSB4	0.00019	0.0012	0.7592	2700
20022	DRAX4	KEAD4	0.00016	0.0012	0.3992	3300
20023	DRAX4	KEAD4	0.00033	0.0012	0.3534	3300
20024	KEAD4	STSB4	0.005	0.018	0.1466	1040
20025	KEAD4	STSB4	0.0005	0.016	0.2795	2000
20026	KEAD4_Q1	RATS4	0.001	0.00702	0.2651	2150
20027	KEAD4_Q2	RATS4	0.001	0.00702	0.4573	2150
20028	KEAD4	WALP4	0.00056	0.0141	0.4496	3300
20029	KEAD4	WALP4	0.00056	0.0141	0.4496	3300
20030	KEAD4_Q3	PELH4	0.00145	0.01454	0.9169	2780
20031	KEAD4_Q4	PELH4	0.00145	0.01454	0.9169	2780
20032	KEAD4	ECLA4	0.00178	0.0172	0.627	2010
20033	KEAD4	ECLA4	0.00178	0.0172	0.8403	2010
20034	RATS4	FECK4	0.00042	0.0018	0.2349	3300
20035	RATS4	FECK4	0.00042	0.0018	0.2349	3000
20036	RATS4	ECLA4	0.00069	0.0097	0.4574	2000
20037	RATS4	ECLA4	0.00068	0.0097	0.4566	2000
20038	FECK4	MELK4	0.00117	0.0096	0.4122	1970
20039	FECK4	MELK4	0.00138	0.0096	0.4829	1970
20040	WALP4	BRFO4	0.00132	0.0143	0.3656	3300
20041	WALP4	BRFO4	0.00178	0.0213	0.6682	3300
20042	WALP4	PELH4	0.00037	0.0059	0.2955	3100
20043	WALP4	PELH4	0.00037	0.0059	0.294	3100
20044	BEAU4	PEHE4	0.001	0.0148	0.4917	3460
20045	BEAU4	PEHE4	0.001	0.0148	0.4917	3460
20046	BEAU4	ERRO4	0.001	0.0148	0.4917	3460
20047	BEAU4	ERRO4	0.001	0.0148	0.4917	3460
20048	BRFO4	PELH4	0.0012	0.0048	0.7	3100
20049	BRFO4	PELH4	0.0012	0.0048	0.4446	2700
20050	BRFO4	GRAI4	0.00035	0.0023	0.2249	2210
20051	BRFO4	GRAI4	0.00035	0.0023	0.2249	2400
20052	PELH4	ECLA4	0.00048	0.0061	0.3041	3100
20053	PELH4	ECLA4	0.00019	0.00111	0.1232	3100
20054	PELH4	LOND4	0.00025	0.01	0.1586	2780
20055	PELH4	LOND4	0.00025	0.01	0.1586	2780
20056	ECLA4	MELK4	0.00039	0.003	0.2466	2780
20057	ECLA4	MELK4	0.00055	0.003	0.3468	2780

20058	ECLA4	LOND4	0.00034	0.0041	0.429	1590
20059	ECLA4	LOND4	0.00037	0.0041	0.4098	1590
20060	MELK4	SWPE4	0.00151	0.0182	0.53	2010
20061	MELK4	SWPE4	0.00151	0.0182	0.53	2010
20062	BRLE4	MELK4	0.00023	0.0007	2.8447	1389
20063	BRLE4	MELK4	0.00086	0.0008	0.9622	1389
20064	BRLE4	LOND4	0.00104	0.0095	0.2918	2200
20065	BRLE4	LOND4	0.00104	0.0095	0.2918	2200
20066	BRLE4	LOVE4	0.00068	0.007	0.2388	2210
20067	BRLE4	LOVE4	0.00068	0.007	0.2388	2210
20068	GRAI4	LOND4_Q1	0.0002	0.0045	0.532	2000
20069	GRAI4	LOND4_Q2	0.0002	0.0045	0.532	2000
20070	SELL4	GRAI4_Q1	0.0002	0.00133	0.1797	3100
20071	SELL4	GRAI4_Q2	0.0002	0.00133	0.1797	3100
20072	SELL4	LOVE4	0.00038	0.00711	0.2998	3070
20073	SELL4	LOVE4	0.00038	0.00711	0.2998	3070
20074	LOVE4	SWPE4	0.00051	0.00796	0.34	2780
20075	LOVE4	SWPE4	0.00051	0.00796	0.34	2780
20076	PEHE4	ERRO4	0.03004	0.077	0.0124	3460
20077	PEHE4	BONN4	0.002	0.019	0.5	3460
20078	PEHE4	BONN4	0.002	0.019	0.5	3460
20079	ERRO4	BONN4	0.001	0.0148	0.4917	3460
20080	ERRO4	BONN4	0.001	0.0148	0.4917	3460
20081	BONN4	NEIL4	0.001	0.024	0.125	1000
20082	BONN4	NEIL4	0.001	0.024	0.125	1000
20083	BONN4	STHA4	0.0013	0.023	0.16256	1700
20084	BONN4	STHA4	0.0013	0.023	0.16256	1700
20085	BONN4	TORN4	0.00211	0.0135	0.1174	1500
20086	BONN4	TORN4	0.0021	0.0135	0.1538	1500
20087	NEIL4	STHA4	0.00085	0.01051	0.38254	2500
20088	NEIL4	STHA4	0.00151	0.01613	0.59296	2500
20089	STHA4	TORN4	0.0017	0.0163	0.4692	1390
20090	STHA4	TORN4	0.0017	0.0163	0.4692	1390
20091	STHA4	HARK4	0.00078	0.00852	0.4635	2170
20092	STHA4	HARK4	0.00078	0.00852	0.0737	2170
20093	TORN4	ECCL4	0.0004	0.0001	1.2872	2500
20094	TORN4	ECCL4	0.0004	0.0001	0.728	2180
20095	ECCL4	STEW4	0.00083	0.0175	0.6624	2770
20096	ECCL4	STEW4	0.00083	0.0175	0.6624	2770
20097	PEWO4	MERS4	0.000887	0.009606	0.066274	1520

20098	PEWO4	MERS4	0.000887	0.009606	0.066274	1520
20099	LOND4	GRAI4	0.0007	0.007	0.22	2000
20100	LOND4	GRAI4	0.0007	0.007	0.22	2000
20101	HARK4	PEWO4	0.001269	0.015642	0.488243	2770
20102	HARK4	PEWO4	0.001269	0.015642	0.488243	2770
20103	STEW4	DRAX4	0.00053	0.00835	5.373	2420
20104	STEW4	DRAX4	0.00053	0.00835	5.373	2420

<u>QB data:</u>

Only the 400 kV QBs of the England and Wales region of GB system are included in the test system. Each QB is assumed to have a thermal rating that matches or exceeds that of the branch it is connected to in both continuous or short-term operation so that the branch is always the limiting component. Each is assumed to have 37 taps with tap 0 the neutral tap (no phase shift). Every tap contributes to an additional 0.6 degrees of phase shift that gives a total range of -10.8 to +10.8 degrees of phase shift angle. A positive phase shift means that the QB is blocking power when the direction of flow is from Node1 to Node2.

Table Ap. -4: Branch data (QB)

FnKey	Node1	Node2	Group	BR_R (pu)	BR_X (pu)	BR_B (pu)	tap min	neutral tap	tap max	degrees per tap
50001	PEWO4	PEWO4_Q1	West	0	0.0037	0	-18	0	+18	0.6
50002	PEWO4	PEWO4_Q2	West	0	0.0037	0	-18	0	+18	0.6
50003	DEES4	DEES4_Q1	West	0	0.0037	0	-18	0	+18	0.6
50004	DEES4	DEES4_Q2	West	0	0.0037	0	-18	0	+18	0.6
50005	STSB4	STSB4_Q1	Central	0	0.0037	0	-18	0	+18	0.6
50006	KEAD4	KEAD4_Q1	East	0	0.0037	0	-18	0	+18	0.6
50007	KEAD4	KEAD4_Q2	East	0	0.0037	0	-18	0	+18	0.6
50008	KEAD4	KEAD4_Q3	East	0	0.0037	0	-18	0	+18	0.6
50009	KEAD4	KEAD4_Q4	East	0	0.0037	0	-18	0	+18	0.6

50010	LOND4	LOND4_Q1	South coast	0	0.0037	0	-18	0	+18	0.6
50011	LOND4	LOND4_Q2	South coast	0	0.0037	0	-18	0	+18	0.6
50012	GRAI4	GRAI4_Q1	South coast	0	0.0037	0	-18	0	+18	0.6
50013	GRAI4	GRAI4_Q2	South coast	0	0.0037	0	-18	0	+18	0.6

Interconnector data:

The interconnection capacity of the GB system to Europe and Ireland is modelled in test network as follows.

Table Ap. -5: Interconnector data

FnKey	Node	Flop	kV	Interconnector	TEC (MW)	Connects to
40001	STHA4	S9	400	MOYLE	500	IE
40002	DEES4	M5	400	EAST-WEST	500	IE
40003	STEW4	Q6	400	NSN	1400	NO
40004	GRAI4	C3	400	BRITNED	1000	NL
40005	SELL4	C7	400	NEMO	1000	BE
40006	SELL4	C9	400	IFA & ELECLINK	3000	FR
40007	LOVE4	B2	400	IFA2	1000	FR

Generation capacity and dispatch

In this section present data for the generation capacity of the test model and we provide an active power dispatch. The generation capacity is based on the projection of Future Energy Scenarios 2016 (FES 16) for the year 2020 (Gone Green scenario) as provided in the ELSI market dispatch model. The capacity of each "ELSI zone" has been allocated to the corresponding test model node. The generation is dispatched according to the SQSS economy criterion to meet the peak demand of 56076 MW

Generation type	Directly scaled factor	Variably scaled ranking	TEC	Directly scaled MW	Variable scaled MW	Dispatch MW
Air	0.5		0	0	0	0
Battery	0.5		0	0	0	0
Biomass	0	3	4480	0	0	0
CHP	0	2	3180	0	0	0
Coal	0	4	1290	0	0	0
CCGT	0	1	24670	0	18504.3	18504.3
Hydro	0.2		1800	360	0	360
NotIdentified	0		0	0	0	0
Nuclear	0.85		8990	7641.5	0	7641.5
OCGT	0		5810	0	0	0
OffWind	0.7		9920	6944	0	6944
OnWind	0.7		12580	8806	0	8806
Other	0		0	0	0	0
Pumped	0.5		4220	2110	0	2110
Solar	0.2		16240	3248	0	3248
Tidal	0.7		90	63	0	63
Wave	0.7		0	0	0	0
Interconnector	1		8400	8400	0	8400
SUM			101670	37572.5	18504.3	56076.8

Generation Capacity (TEC) in MW	Biomass	CHP	Hydro	OCGT	OffWind	OnWind	Pumped	Solar	Tidal	CCGT	Nuclear	Coal
BEAU4	20	10	670	10	560	2680	300	50	30	0	0	0
PEHE4	0	40	0	10	0	390	0	40	0	400	0	0
ERRO4	10	10	700	10	0	690	0	80	10	0	0	0
BONN4	30	90	10	20	10	300	440	70	0	0	0	0
NEIL4	0	0	0	0	0	0	0	0	0	0	954.4186	0
STHA4	100	250	140	0	0	2937	0	160	0	0	0	0
TORN4	0	0	0	0	470	1513	0	0	0	0	1205.581	0
HARK4	0	20	10	0	180	140	0	70	0	0	0	0
STEW4	530	510	20	280	70	380	0	260	0	60	1210	0
PEWO4	10	310	20	80	1650	170	100	100	0	0	2410	0
DEES4	0	20	120	30	1010	300	2000	260	0	0	0	0
DRAX4	3000	0	0	0	0	355	0	740	0	0	0	1280
KEAD4	20	190	20	200	1030	555	0	800	0	8800	0	0
RATS4	150	0	0	0	0	85	0	1420	0	0	0	0
FECK4	0	410	10	0	0	85	200	0	0	0	0	0
WALP4	0	10	0	140	820	180	0	270	0	820	0	0
BRFO4	80	30	0	70	2510	40	0	890	0	410	1220	10
PELH4	0	85	0	0	0	160	0	2200	0	493.3333	0	0
ECLA4	0	85	0	0	0	160	0	0	0	246.6667	0	0
MELK4	130	150	70	880	0	740	680	2910	20	5100	0	0
BRLE4	10	20	0	90	0	0	0	150	0	50	0	0
LOND4	120	290	0	840	0	20	100	340	0	1190	0	0
GRAI4	60	60	0	1090	0	80	0	500	0	2800	0	0
SELL4	0	10	0	220	1100	70	0	370	0	0	1080	0
LOVE4	110	270	0	550	400	0	0	1040	0	1320	0	0
SWPE4	40	40	10	450	0	350	400	3150	30	970	910	0

MERS4	60	270	0	840	110	200	0	370	0	2010	0	0

Generation Dispatch in MW												
	Biomass	CHP	Hydro	OCGT	OffWind	OnWind	Pumped	Solar	Tidal	CCGT	Nuclear	Coal
BEAU4	0	0	134	0	392	1876	150	10	21	0	0	0
PEHE4	0	0	0	0	0	273	0	8	0	300.0292	0	0
ERRO4	0	0	140	0	0	483	0	16	7	0	0	0
BONN4	0	0	2	0	7	210	220	14	0	0	0	0
NEIL4	0	0	0	0	0	0	0	0	0	0	811.2558	0
STHA4	0	0	28	0	0	2055.9	0	32	0	0	0	0
TORN4	0	0	0	0	329	1059.1	0	0	0	0	1024.744	0
HARK4	0	0	2	0	126	98	0	14	0	0	0	0
STEW4	0	0	4	0	49	266	0	52	0	45.00438	1028.5	0
PEWO4	0	0	4	0	1155	119	50	20	0	0	2048.5	0
DEES4	0	0	24	0	707	210	1000	52	0	0	0	0
DRAX4	0	0	0	0	0	248.5	0	148	0	0	0	0
KEAD4	0	0	4	0	721	388.5	0	160	0	6600.642	0	0
RATS4	0	0	0	0	0	59.5	0	284	0	0	0	0
FECK4	0	0	2	0	0	59.5	100	0	0	0	0	0
WALP4	0	0	0	0	574	126	0	54	0	615.0598	0	0
BRFO4	0	0	0	0	1757	28	0	178	0	307.5299	1037	0
PELH4	0	0	0	0	0	112	0	440	0	370.036	0	0
ECLA4	0	0	0	0	0	112	0	0	0	185.018	0	0
MELK4	0	0	14	0	0	518	340	582	14	3825.372	0	0
BRLE4	0	0	0	0	0	0	0	30	0	37.50365	0	0
LOND4	0	0	0	0	0	14	50	68	0	892.5868	0	0
GRAI4	0	0	0	0	0	56	0	100	0	2100.204	0	0

SELL4	0	0	0	0	770	49	0	74	0	0	918	0
LOVE4	0	0	0	0	280	0	0	208	0	990.0963	0	0
SWPE4	0	0	2	0	0	245	200	630	21	727.5708	773.5	0
MERS4	0	0	0	0	77	140	0	74	0	1507.647	0	0

Zonal to nodal generation allocation

The following tables, based on info from [164], determines how the zonal generation capacity or a dispatch of the ELSI model is must be allocated to the test model nodes. The second one (Table Ap. -7) covers the case of certain ELSI zones that cannot be allocated to a single test model node. The capacity or dispatch of these zones has to be split between the nodes according to the provided distribution factors.

Table Ap. -6: ELSI zone to test network node allocation - I

ELSI zone	Test model node	ELSI zone	Test model node
GB_A	LOND4	**GB_S1**	LOVE4
GB_B	BRLE4	**GB_T**	SELL4
GB_C	GRAI4	**GB_U**	BRFO4
GB_C1	SELL4	**GB_V**	DEES4
GB_D	PELH4/ECLA4 – See Table Ap. -7 /Part 2	**GB_W**	ERRO4
GB_E	SWPE4	**GB_X**	ERRO4
GB_F	SWPE4	**GB_Y**	PEHE4
GB_G	MELK4	**GB_Y1**	PEHE4
GB_H	MELK4	**GB_Z**	BEAU4
GB_I	NEIL4/STHA4/TORN4/ECCL4 - See Table Ap. -7/Part 1	**GB_Z1**	BEAU4
GB_J	PELH4/ECLA4 – See Table Ap. -7 /Part 2	**GB_1**	SWPE4
GB_K	KEAD4	**GB_2**	WALP4
GB_L	RATS4/FECK4 – See Table Ap. -7 / Part 4	**GB_3**	DEES4
GB_M	DEES4	**GB_4**	DEES4
GB_N	MERS4	**GB_5**	DEES4
GB_O	BONN4	**GB_6**	KEAD4
GB_P	DRAX4/KEAD4 –See Table Ap. -7 / Part 3	**GB_7**	STEW4
GB_Q	HARK4	**GB_8**	BEAU4
GB_R	PEWO4	**GB_9**	MELK4

GB_S	LOVE4	**GB_0**	MELK4

Table Ap. -7: ELSI zone to test network node allocation - II

Generation type	Part 1 Zone I rule				Part 2 Zones D and J rule		Part 3 Zone P rule		Part 4 Zone L rule	
	NEIL4	STHA4	TORN4	ECCL4	PELH4	ECLA4	DRAX4	KEAD4	RATS4	FECK4
Air	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Battery	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Biomass	0	1	0	0	n/a	n/a	1	0	1	0
CHP	0	1	0	0	0.5	0.5	0	1	0	1
Coal	n/a	n/a	n/a	n/a	n/a	n/a	1	0	1/3	2/3
CCGT	n/a	n/a	n/a	n/a	2/3	1/3	0	1	n/a	n/a
Hydro	0	1	0	0	n/a	n/a	0	1	0	1
Nuclear	0.44186	0	0.55814	0	n/a	n/a	n/a	n/a	n/a	n/a
OCGT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
OffWind	0	0	1	0	n/a	n/a	0	1	n/a	n/a
OnWind	0	0.66	0.34	0	0.5	0.5	0.5	0.5	0.5	0.5
Other	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pumped	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	1
Solar	0	1	0	0	1	0	1	0	1	0
Tidal	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Wave	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Appendix E: Study setup

In this appendix additional details are provided about how the year around study is set up and the input data choices made. Note the modelling setup and assumptions used should only be viewed in the context of this thesis. They are relevant to the test model used. They should not be attributed to any operational practices of the ESO.

Year round market dispatch

The National Grid Electricity Scenario Illustrator model (ELSI) is used to produce a year round market dispatch [194]. ELSI is an excel based economic dispatch and constraint cost modelling tool and the latest public version can be found in [191][147]. It is preconfigured with the National Grid Future Energy Scenario 2016 data set [23] - excluding the EU to GB interconnection capacity that must be set up by the user. Info on the latter can be found in reference [192]. ELSI uses a zonal representation for the generation and demand. Network capacity is modelled by boundaries or interconnectors.

ELSI was used to produce an 'unconstrained' North West Europe (NWE) economic 'dispatch'. This means that the economic dispatch optimisation model was solved for the entirety of north west Europe and GB. Further, while no GB transmission network constraints (boundary flow constraints) were considered (hence unconstrained), the available interconnection capacity between EU countries and between EU counties and GB was taken into account. This is reflected in our analysis in the resulting GB to EU interconnection flows.

ELSI separates each 24-hour day into four periods based on the shape of the demand curve (peak, plateau, pickup/drop off and night through) and provides a single dispatch snapshot - also called "slot"- for each. It is assumed that in the remaining hours of the period the dispatch will be the same. As a result, 1460 slots/snapshots are produced for each calendar year.

For this thesis, an unconstrained NWE dispatch of the year 2020 according to the Gone Green 2016 Future Energy Scenario was obtained as a starting point for testing the QB coordination framework.

147 Note ELSI has been replaced by the more advanced Afry Bid3 software tool within National Grid ESO. ELSI is still useful for research and education.

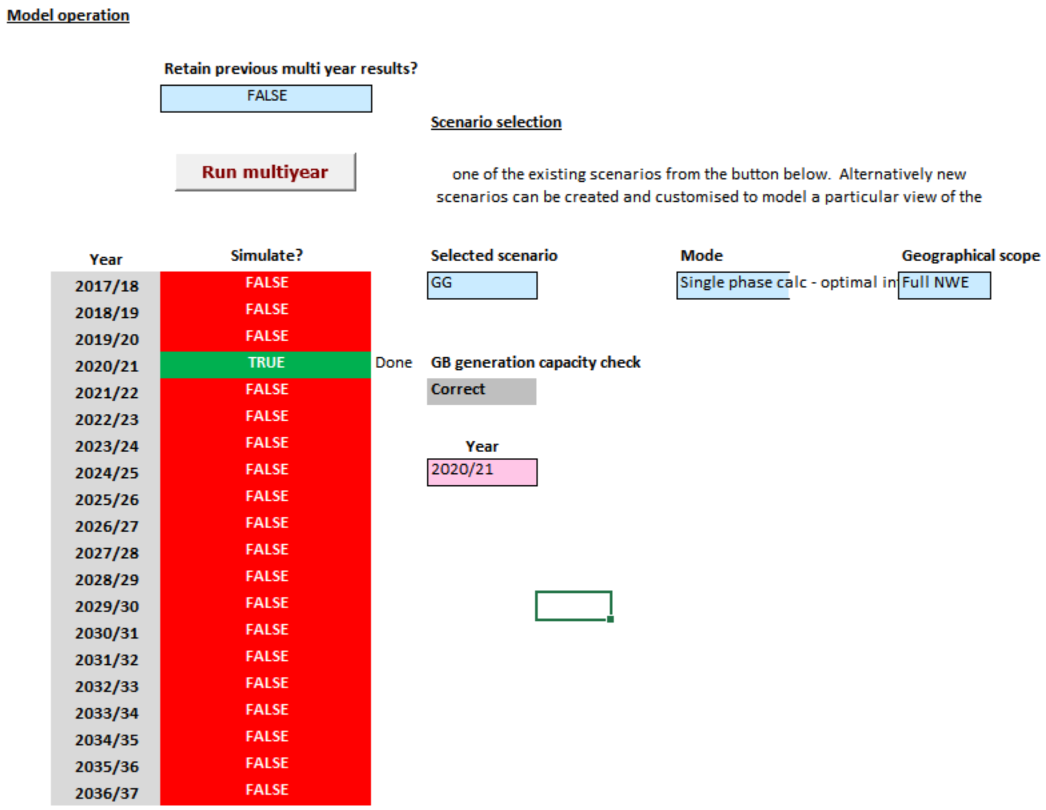

Figure Ap. -5: Settings of the ELSI model (Control tab)

West coast HVDC link

The west coast HVDC (W-HVDC) is a 2.2 GW Line Commutated Converter (LCC) 385 km link that connects the Hunterston substation in Scotland to the Flintshire Bridge substation in North Wales (which is adjacent to the Connah's Quay substation)[148]. It was commissioned in December 2017 and it is jointly owned by the National Grid Electricity Transmission (NGET) and Scottish Power Transmission (SPT) TOs. The link bypasses the onshore transmission network limitations in the Scottish border area (boundary B6) and in Teeside and Mersey Ring ones (boundary B7a) and it brings power from Scotland closer to the demand centres of the Midlands and the south of England.

The W-HVDC is a controllable transmission network asset and its output can be directly set by the ESO. The following simple rule is used to determine the output of the link for each dispatch period initially – before the process enters the QB coordination framework. The rule is based on the difference between the generation and demand dispatched in Scotland ("B6 Net flow" in Figure Ap. -6). The rule aims to maximise the use of the link at medium and high B6 boundary transfers in order to reduce the loading of the onshore circuits. At low B6 transfer

148 It connects Neilston to Deeside nodes in the test model

levels, that pose no risk for overloading the onshore circuits after a fault, the link is kept at a lower transfer level. The assumption is that a minimum level of loading is needed on the onshore AC circuits in the bypassed areas to reduce the voltage gain that can make voltage management more challenging [195]. In short, the link is dispatched to its full capacity of 2 GW[149] when "B6 Net " flow exceeds 3500 MW. For B6 net flow between 0 MW to 3500 MW, the MW set-point of the link increases in gradual steps. The direction of flow through the link (north to south or the opposite) follows that of the AC overhead lines.

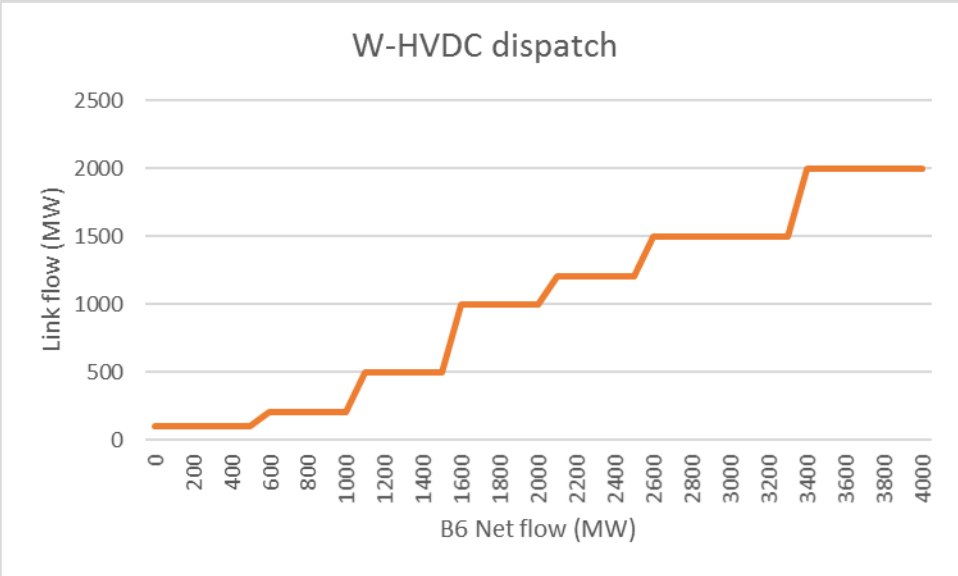

Figure Ap. -6: Rule for the W-HVDC dispatch

Note also that the rule is not based on and should not be attributed to any operational practices of the ESO. It is an assumed link dispatch used for the purposes of this thesis. It simply aims to provide a reasonable W-HVDC set-point at the start of the QB coordination framework.

W-HVDC as a control variable

In the framework, the W-HVDC link can be used for both preventive and corrective actions. The set point of the link is coordinated with the QB tap settings. Due to the converter and cable technology, when the link is used for corrective actions it is not possible to reverse the direction of flow (See Appendix E of [50]). So in the QB coordination framework (in the Post-Contingency OPF) it is only allowed to de-load to the "float" position – close to zero.

Contingencies and monitored circuits

The test network branches below are monitored for overloads (i.e. are included in the OPF as optimisation constraints):

- All circuits in the National Grid Electricity Transmission TO area

149 A more conservative "continuous" rating of the link rather than the nameplate capacity of 2.2 GW is used.

- All circuits in the Scottish Power Transmission TO area
- Circuits crossing the Scotland to England boundary

The circuits further north, in the SHET TO area are not monitored for overloads as the test network is not detailed enough to capture the network structure in that area and the England and Wales QBs have no effect on them.

The following table lists the unplanned branch network outages that are considered as contingencies. The fault outage of the W-HVDC link is also considered as an unplanned event that the network has to be secured against in the study. The contingency link outage is modelled by re-dispatching the two generators modelling the link power injections to zero.

The assumption about what contingencies and monitored circuits to include in the study setup should only be viewed for the purpose of this thesis. It is relevant to the test model. It is not based on and should not be attributed to any operational practice of the ESO

Table Ap. -8: Considered contingencies

FnKey	FnKey1	FnKey2	Branch1_Node 1	Branch1_Flop 1	Branch1_Node 2	Branch1_Flop 2	Branch2_Node 1	Branch2_Flop 1	Branch2_Node 2	Branch2_Flop 2	TO	Case_ Type
60001	20001	20002	STEW4	Q	DRAX4	P	STEW4	Q	DRAX4	P	NGET	ND
60002	20003	20004	STEW4	Q	HARK4	Q	STEW4	Q	HARK4	Q	NGET	ND
60003	20005	20006	MERS4	R	DEES4	M	MERS4	R	DEES4	M	NGET	ND
60004	20007	20008	PEWO4_Q1	R	DAIN4	N	PEWO4_Q2	R	DRAX4	N	NGET	ND
60005	20008	20009	PEWO4_Q2	R	DRAX4	N	DAIN4	P	DRAX4	N	NGET	ND
60006	20007	20009	PEWO4_Q1	R	DAIN4	N	DAIN4	P	DRAX4	N	NGET	ND
60007	20010	20011	DEES4_Q1	M	FECK4	L	DEES4_Q2	M	FECK4	L	NGET	ND
60008	20012	20013	DAIN4	N	DEES4	M	DAIN4	N	DEES4	M	NGET	ND
60009	20014	20015	DAIN4	N	STSB4	P	DAIN4	N	STSB4_Q1	P	NGET	ND
60010	20016	20017	DAIN4	N	FECK4	L	DAIN4	N	FECK4	L	NGET	ND
60011	20018	20019	DRAX4	P	DAIN4	N	DRAX4	P	DAIN4	N	NGET	ND
60012	20020	20021	DRAX4	P	STSB4	P	DRAX4	P	STSB4	P	NGET	ND
60013	20022	20023	DRAX4	P	KEAD4	P	DRAX4	P	KEAD4	P	NGET	ND
60014	20024	20025	KEAD4	P	STSB4	P	KEAD4	P	STSB4	P	NGET	ND
60015	20026	20027	KEAD4_Q1	P	RATS4	L	KEAD4_Q2	P	RATS4	L	NGET	ND
60016	20028	20029	KEAD4	P	WALP4	J	KEAD4	P	WALP4	J	NGET	ND
60017	20030	20031	KEAD4_Q3	P	PELH4	D	KEAD4_Q4	P	PELH4	D	NGET	ND
60018	20032	20033	KEAD4	P	ECLA4	D	KEAD4	P	ECLA4	D	NGET	ND
60019	20034	20035	RATS4	L	FECK4	L	RATS4	L	FECK4	L	NGET	ND
60020	20036	20037	RATS4	L	ECLA4	D	RATS4	L	ECLA4	D	NGET	ND
60021	20038	20039	FECK4	L	MELK4	H	FECK4	L	MELK4	H	NGET	ND
60022	20040	20041	WALP4	J	BRFO4	J	WALP4	J	BRFO4	J	NGET	ND
60023	20042	20043	WALP4	J	PELH4	D	WALP4	J	PELH4	D	NGET	ND
60024	20048	20049	BRFO4	J	PELH4	D	BRFO4	J	PELH4	D	NGET	ND
60025	20050	20051	BRFO4	J	GRAI4	C	BRFO4	J	GRAI4	C	NGET	ND

60026	20052	20053	PELH4	D	ECLA4	D	PELH4	D	ECLA4	D	NGET	ND
60027	20054	20055	PELH4	D	LOND4	A	PELH4	D	LOND4	A	NGET	ND
60028	20056	20057	ECLA4	D	MELK4	H	ECLA4	D	MELK4	H	NGET	ND
60029	20058	20059	ECLA4	D	LOND4	A	ECLA4	D	LOND4	A	NGET	ND
60030	20060	20061	MELK4	H	SWPE4	F	MELK4	H	SWPE4	F	NGET	ND
60031	20062	20063	BRLE4	B	MELK4	H	BRLE4	B	MELK4	H	NGET	ND
60032	20064	20065	BRLE4	B	LOND4	A	BRLE4	B	LOND4	A	NGET	ND
60033	20066	20067	BRLE4	B	LOVE4	B	BRLE4	B	LOVE4	B	NGET	ND
60034	20068	20069	GRAI4	C	LOND4_Q1	A	GRAI4	C	LOND4_Q2	A	NGET	ND
60035	20070	20071	SELL4	C	GRAI4_Q1	C	SELL4	C	GRAI4_Q2	C	NGET	ND
60036	20072	20073	SELL4	C	LOVE4	B	SELL4	C	LOVE4	B	NGET	ND
60037	20074	20075	LOVE4	B	SWPE4	F	LOVE4	B	SWPE4	F	NGET	ND
60038	20097	20098	PEWO4	R	MERS4	N	PEWO4	R	MERS4	N	NGET	ND
60039	20099	20100	LOND4	A	GRAI4	C	LOND4	A	GRAI4	C	NGET	ND
60040	20101	20102	HARK4	Q	PEWO4	R	HARK4	Q	PEWO4	R	NGET	ND
60041	20091	20092	STHA4	S	HARK4	Q	STHA4	S	HARK4	Q	BORDER2	ND
60042	20095	20096	ECCL4	S	STEW4	Q	ECCL4	S	STEW4	Q	BORDER2	ND
60151	20103	20104	STEW4	Q	DRAX4	P	STEW4	Q	DRAX4	P	NGET	ND
60049	20001	0	STEW4	Q	DRAX4	P					NGET	N1
60050	20002	0	STEW4	Q	DRAX4	P					NGET	N1
60051	20003	0	STEW4	Q	HARK4	Q					NGET	N1
60052	20004	0	STEW4	Q	HARK4	Q					NGET	N1
60053	20005	0	MERS4	R	DEES4	M					NGET	N1
60054	20006	0	MERS4	R	DEES4	M					NGET	N1
60055	20007	0	PEWO4_Q1	R	DAIN4	N					NGET	N1
60056	20008	0	PEWO4_Q2	R	DRAX4	N					NGET	N1
60057	20009	0	DAIN4	P	DRAX4	N					NGET	N1
60058	20010	0	DEES4_Q1	M	FECK4	L					NGET	N1

60059	20011	0	DEES4_Q2	M	FECK4	L	NGET	N1
60060	20012	0	DAIN4	N	DEES4	M	NGET	N1
60061	20013	0	DAIN4	N	DEES4	M	NGET	N1
60062	20014	0	DAIN4	N	STSB4	P	NGET	N1
60063	20015	0	DAIN4	N	STSB4_Q1	P	NGET	N1
60064	20016	0	DAIN4	N	FECK4	L	NGET	N1
60065	20017	0	DAIN4	N	FECK4	L	NGET	N1
60066	20018	0	DRAX4	P	DAIN4	N	NGET	N1
60067	20019	0	DRAX4	P	DAIN4	N	NGET	N1
60068	20020	0	DRAX4	P	STSB4	P	NGET	N1
60069	20021	0	DRAX4	P	STSB4	P	NGET	N1
60070	20022	0	DRAX4	P	KEAD4	P	NGET	N1
60071	20023	0	DRAX4	P	KEAD4	P	NGET	N1
60072	20024	0	KEAD4	P	STSB4	P	NGET	N1
60073	20025	0	KEAD4	P	STSB4	P	NGET	N1
60074	20026	0	KEAD4_Q1	P	RATS4	L	NGET	N1
60075	20027	0	KEAD4_Q2	P	RATS4	L	NGET	N1
60076	20028	0	KEAD4	P	WALP4	J	NGET	N1
60077	20029	0	KEAD4	P	WALP4	J	NGET	N1
60078	20030	0	KEAD4_Q3	P	PELH4	D	NGET	N1
60079	20031	0	KEAD4_Q4	P	PELH4	D	NGET	N1
60080	20032	0	KEAD4	P	ECLA4	D	NGET	N1
60081	20033	0	KEAD4	P	ECLA4	D	NGET	N1
60082	20034	0	RATS4	L	FECK4	L	NGET	N1
60083	20035	0	RATS4	L	FECK4	L	NGET	N1
60084	20036	0	RATS4	L	ECLA4	D	NGET	N1
60085	20037	0	RATS4	L	ECLA4	D	NGET	N1
60086	20038	0	FECK4	L	MELK4	H	NGET	N1

60087	20039	0	FECK4	L	MELK4	H	NGET	N1
60088	20040	0	WALP4	J	BRFO4	J	NGET	N1
60089	20041	0	WALP4	J	BRFO4	J	NGET	N1
60090	20042	0	WALP4	J	PELH4	D	NGET	N1
60091	20043	0	WALP4	J	PELH4	D	NGET	N1
60092	20048	0	BRFO4	J	PELH4	D	NGET	N1
60093	20049	0	BRFO4	J	PELH4	D	NGET	N1
60094	20050	0	BRFO4	J	GRAI4	C	NGET	N1
60095	20051	0	BRFO4	J	GRAI4	C	NGET	N1
60096	20052	0	PELH4	D	ECLA4	D	NGET	N1
60097	20053	0	PELH4	D	ECLA4	D	NGET	N1
60098	20054	0	PELH4	D	LOND4	A	NGET	N1
60099	20055	0	PELH4	D	LOND4	A	NGET	N1
60100	20056	0	ECLA4	D	MELK4	H	NGET	N1
60101	20057	0	ECLA4	D	MELK4	H	NGET	N1
60102	20058	0	ECLA4	D	LOND4	A	NGET	N1
60103	20059	0	ECLA4	D	LOND4	A	NGET	N1
60104	20060	0	MELK4	H	SWPE4	F	NGET	N1
60105	20061	0	MELK4	H	SWPE4	F	NGET	N1
60106	20062	0	BRLE4	B	MELK4	H	NGET	N1
60107	20063	0	BRLE4	B	MELK4	H	NGET	N1
60108	20064	0	BRLE4	B	LOND4	A	NGET	N1
60109	20065	0	BRLE4	B	LOND4	A	NGET	N1
60110	20066	0	BRLE4	B	LOVE4	B	NGET	N1
60111	20067	0	BRLE4	B	LOVE4	B	NGET	N1
60112	20068	0	GRAI4	C	LOND4_Q1	A	NGET	N1
60113	20069	0	GRAI4	C	LOND4_Q2	A	NGET	N1
60114	20070	0	SELL4	C	GRAI4_Q1	C	NGET	N1

60115	20071	0	SELL4	C	GRAI4_Q2	C	NGET	N1
60116	20072	0	SELL4	C	LOVE4	B	NGET	N1
60117	20073	0	SELL4	C	LOVE4	B	NGET	N1
60118	20074	0	LOVE4	B	SWPE4	F	NGET	N1
60119	20075	0	LOVE4	B	SWPE4	F	NGET	N1
60120	20091	0	STHA4	S	HARK4	Q	BORDER2	N1
60121	20092	0	STHA4	S	HARK4	Q	BORDER2	N1
60122	20095	0	ECCL4	S	STEW4	Q	BORDER2	N1
60123	20096	0	ECCL4	S	STEW4	Q	BORDER2	N1
60124	20097	0	PEWO4	R	MERS4	N	NGET	N1
60125	20098	0	PEWO4	R	MERS4	N	NGET	N1
60126	20099	0	LOND4	A	GRAI4	C	NGET	N1
60127	20100	0	LOND4	A	GRAI4	C	NGET	N1
60128	20101	0	HARK4	Q	PEWO4	R	NGET	N1
60129	20102	0	HARK4	Q	PEWO4	R	NGET	N1
60130	20093	0	TORN4	S	ECCL4	S	SPT	N1
60131	20094	0	TORN4	S	ECCL4	S	SPT	N1
60132	20089	0	STHA4	S	TORN4	S	SPT	N1
60133	20090	0	STHA4	S	TORN4	S	SPT	N1
60134	20087	0	NEIL4	S	STHA4	S	SPT	N1
60135	20088	0	NEIL4	S	STHA4	S	SPT	N1
60136	20081	0	BONN4	S	NEIL4	S	SPT	N1
60137	20082	0	BONN4	S	NEIL4	S	SPT	N1
60138	20083	0	BONN4	S	STHA4	S	SPT	N1
60139	20084	0	BONN4	S	STHA4	S	SPT	N1
60140	20085	0	BONN4	S	TORN4	S	SPT	N1
60141	20086	0	BONN4	S	TORN4	S	SPT	N1

Seasonal thermal ratings

The ability of an overhead line to transfer power is often limited by its ability to dissipate heat in the environment. In the summer or spring, when the ambient temperature is higher and there is overall less wind to help dissipate the heat, the achieved thermal rating is lower. We use the following scaling factors profile to convert the continuous winter thermal rating to that of summer, autumn and spring. It is an assumption used for the purposes of the study setup and does not correspond to any actual branch of the GB network.

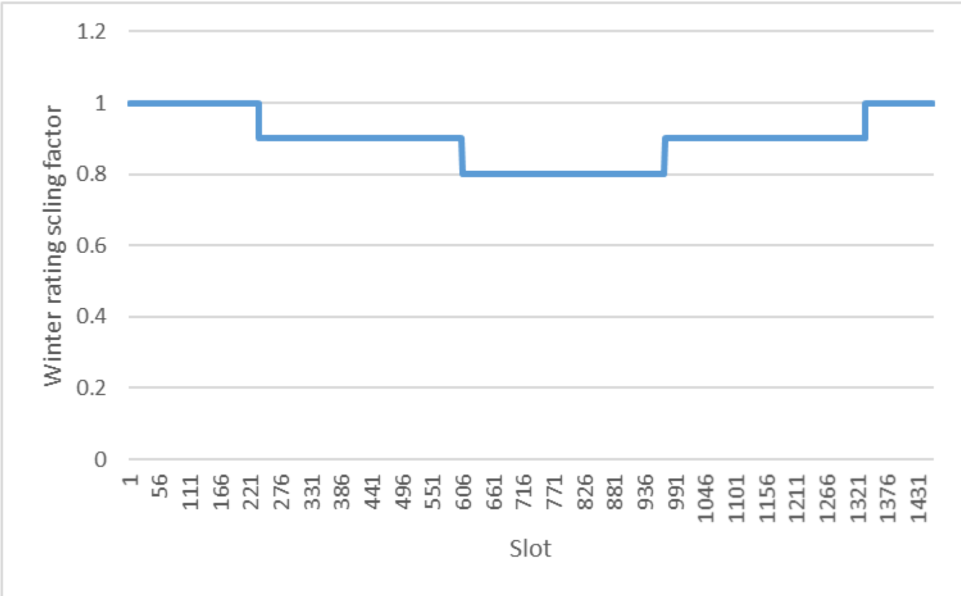

Figure Ap. -7: Winter rating scaling factors profile

Short term thermal ratings

The short-term thermal rating is the loading exceeding the continuous rating that a branch can endure for a limited amount of time – usually up to 20 minutes. For overhead lines, the exact rating depends on the pre-fault loading of the branch that determines the "sag" of the overhead line at the time of the fault. The higher the pre-fault loading/sag the lower the short-term rating that can be achieved so that the clearance below the wires does reach a critical point because of the additional sag. Note that in some occasions equipment in the terminating substations or in series with the branch, such as circuit breakers, cable sections or transformers, may set a hard limit to the short-term rating that can be achieved.

We assume that the following short-term rating factors for all the branches of the test model. It is an assumption used for the purposes of the study setup and does not correspond to any actual branch of the GB network.

Table Ap. -9: Scaling factors for the short-term thermal ratings

Pre-fault loading interval %	**20-minute short-term rating scaling factor**
(84,100]	1.09
(75 , 84]	1.09
(60 , 75]	1.12
(30 , 60]	1.15
(0 , 30]	1.19

Bids and Offers

The values for the generators are adopted from the ELSI model. The Bid values for the interconnectors are set at an assumed, arbitrary value, lower than that of generators (as a negative Bid represent expenditure) so that they are used by the optimiser as last resort measure. This reflects the high cost of re-dispatching interconnectors either through the balancing mechanism, day ahead trading or through a commercial agreement for constraint management.

In the following table, a negative Bid is revenue for the ESO and a positive Bid an expenditure. Offers (always positive) is also an expenditure. Note that some generation types and the interconnectors can only be re-dispatched in one direction.

Table Ap. -10: Bid and Offer values used

BMU type	**Bid (£/MWh)**	**Offer (£/MWh)**
Battery	As in ELSI model	As in ELSI model
Biomass	As in ELSI model	As in ELSI model
CHP	As in ELSI model	As in ELSI model
Coal	As in ELSI model	As in ELSI model
CCGT	As in ELSI model	As in ELSI model
Hydro	As in ELSI model	n/a
OCGT	As in ELSI model	As in ELSI model
OffWind	As in ELSI model	n/a
OnWind	As in ELSI model	n/a
Pumped	As in ELSI model	As in ELSI model
Solar	As in ELSI model	n/a
Tidal	As in ELSI model	n/a
Wave	As in ELSI model	n/a
Interconnector	min generator bid - £100	n/a

The following table presents the Bids and Offers used for the "penalty variables" that are used to prevent infeasibility of the preventive SC-OPF problem. Two penalty "generators" are modelled in each node, one accepting Bids and the other accepting Offers only. In this context "Penalty Bid" is a reduction in the active power injected to the bus and "Penalty Offer" an increase.

Table Ap. -11: Penalty variables

BMU type	Purpose	Bid (£/MWh)	Offer (£/MWh)
Penalty Bid (up to 150 MW)	When Bids of generators are not enough to relieve overload	-500	
Penalty Offer (up to 600 MW)	Models cost to start-up additional plant or demand reduction		+500

Limiting generation re-dispatch post-fault

In the test model we use one generator per type in each test model node that aggregates all the individual plants of the same type in the area. Consequently, each of them has a higher output/capacity than any single plant (BMU) in the area would have. To set an upper bound on the power that the optimiser can re-dispatch in each post-contingency OPF problems to a realistic level the following methods are combined:

- Ramp rates are used for thermal plants – adapted from [106]

Table Ap. -12: Ramp rates for thermal generation

Generation type	ramp down rate (MW/min)	ramp up rate (MW/min)
Biomass	17	17
CHP	17	17
Coal	17	17
CCGT	25	25
OCGT	17	17

- Re-dispatch limit for pumped storage and battery plants: in MW, as a percentage of their dispatched output – assumption.

Table Ap. -13: Capacity made available in the balancing mechanism by pumped storage and battery generation

Generation type	Bid (% of dispatched MW)	Offer (% of dispatched MW)
Pumped storage	30	30
Battery	50	50

- Locational Bid upper bound for wind farms depending on their connection area or node – assumption using info from Transmission Entry Capacity (TEC) Register [196]

Table Ap. -14: Max capacity made available to the balancing mechanism by lumped wind generators in each test network node or FLOP zone

Onshore Wind		**Offshore Wind**	
FLOP Zone	Bid upper bound (MW)	Node	Bid upper bound(MW)
A	80	BEAU4	392
B	80	BONN4	7
C	80	TORN4	329
D	80	HARK4	126
F	80	STEW4	49
H	80	PEWO4	461.3
J	80	DEES4	403.2
L	80	KEAD4	153.3
M	80	WALP4	406
N	80	BRFO4	352.8
P	80	SELL4	441
Q	200	LOVE4	280
R	80	MERS4	77
S	200		
T	150		

- Limit on the number of “model generators” than can be used: max 2 generators for Bid and 3 for Offers – assumption.
- Overall limit on the power that can be re-dispatched: 1000 MW

Appendix F: Year round market dispatch and network constraints

In this section, overview data from the ELSI year round economic dispatch and the network constraints that result when it is applied to the test network are presented. Note they are relevant to the study setup and the test model used. For relevant info about the actual GB system refer to the information the ESO has made available through its publications [168] or the data portal [169].

Generation and demand disposition

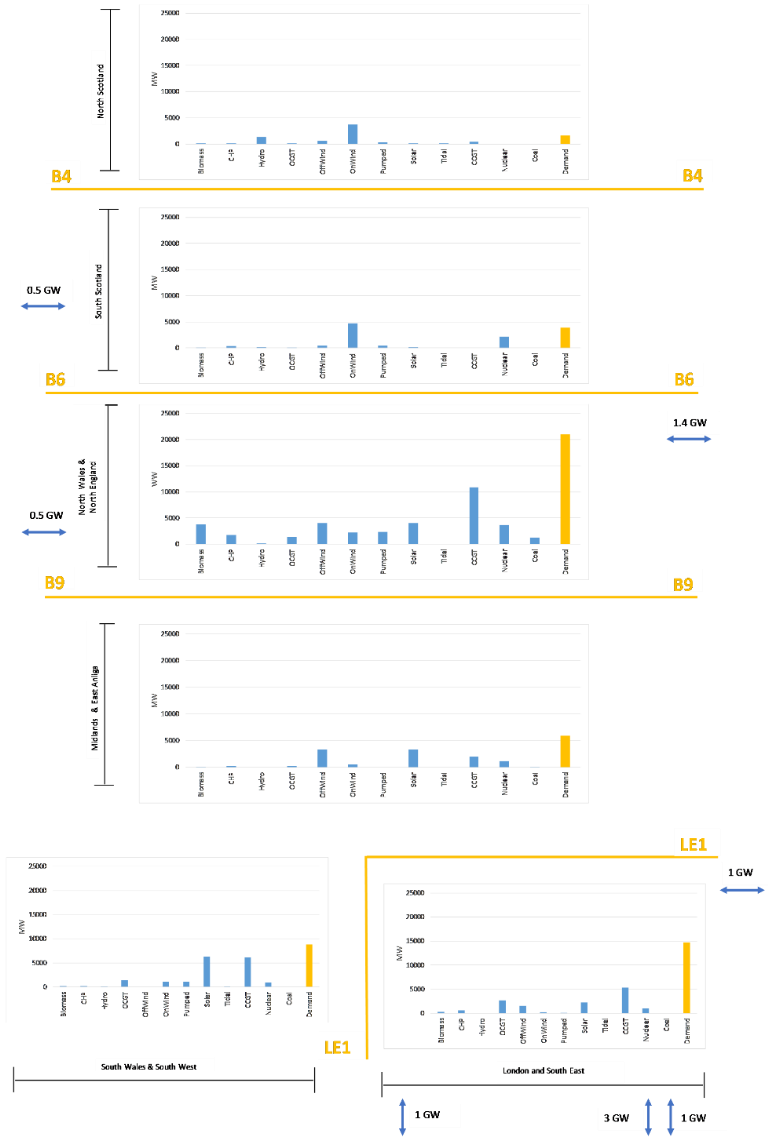

Figure Ap. -8: Disposition of demand and generation in the test network

Generation dispatch by type

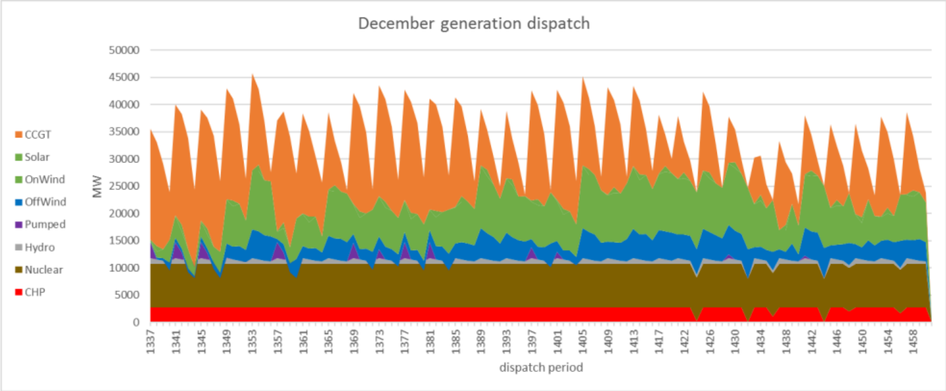

Figure Ap. -9: December generation dispatch

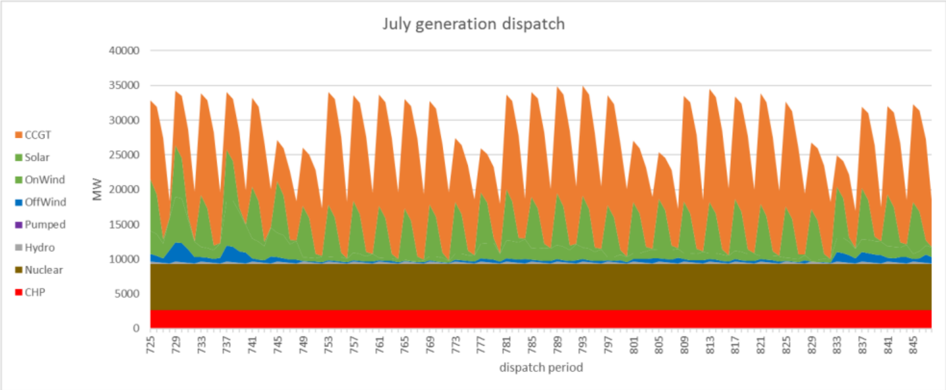

Figure Ap. -10: July generation dispatch

Network flows

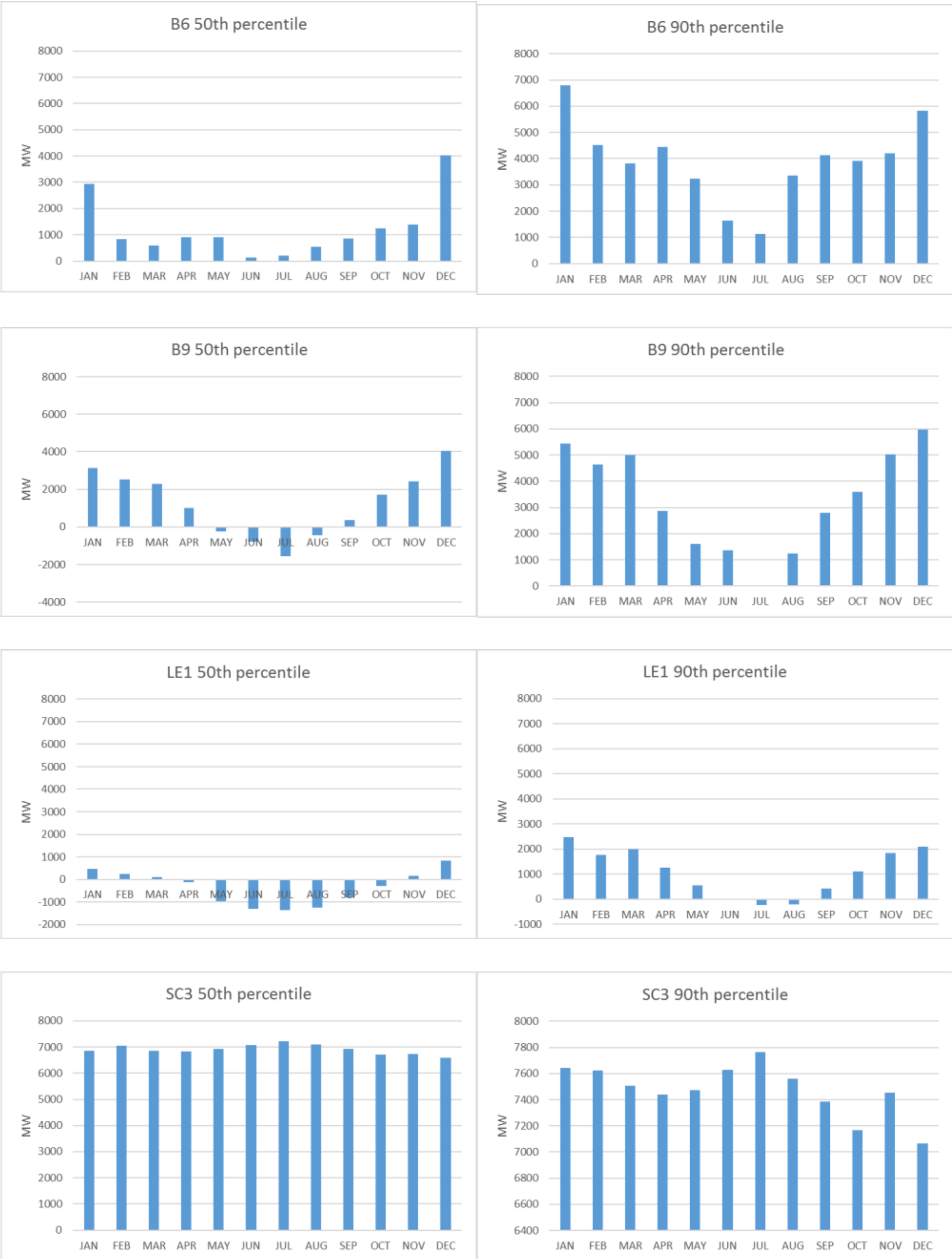

Figure Ap. -11: Network flows across the test system boundaries

Test network constraints

The following tables present the most "severe" network constraints. The test network branches that on average exceed their continuous rating the most or more often and the contingency that causes the worst overload.

Table Ap. -15: Test network constraints - December

Constraint	Worst Contingency	Average flow over cont. rating (MW)
TORN4-ECCL4 ct 1 (ct 2)	TORN4-ECCL4 ct2 (ct 1) N-1	357
STEW4-HARK4 ct 1 & ct 2	ECCL4-STEW4 N-D	252
STHA4-HARK4 ct 1 & ct 2	ECCL4-STEW4 N-D	206
STEW4-DRAX4 ct 1 & ct 2	STEW4-DRAX4 N-D	172
PEWO4_Q1-DAIN4	PEWO4_Q2-DRAX4/DAIN4-DRAX4 N-D	119
PEWO4-MERS4 ct 1 & ct 2	PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4 N-D	83
PEWO4_Q2-DRAX4	PEWO4_Q1-DAIN4 N-1	76
DRAX4-KEAD4 ct 1 (ct 2)	DRAX4-KEAD4 ct 2 (ct 1) N-1	42
ECCL4-STEW4 ct 1 (ct 2)	STHA4-HARK4 N-D	36
ECLA4-LOND4 ct 1 (ct 2)	ECLA4-LOND4 ct 2 (ct 1) N-1	5

Appendix G: Detailed results

Monthly results

The results presented in this section should only be viewed in the context of this thesis. They are specific to the study setup and the input data used. Only publicly available input data were used. The constraint cost figures, either in absolute or incremental form (as for example when comparing two strategies), should not be taken as indicative of the constraint cost expected to be incurred in the actual GB network. For the later please refer to the information the ESO has made available through its publications [168] or the data portal [169].

Table Ap. -16: Monthly preventive generation re-dispatch cost of each strategy

Constraint cost (£m)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
A1	£28.16	£33.48	£19.71	£55.54	£14.33	£20.50	£28.57	£30.20	£48.81	£14.52	£15.51	£134.95
A2	£22.42	£28.57	£15.41	£44.48	£9.15	£19.23	£28.48	£22.84	£37.71	£8.48	£10.35	£106.29
B1	£20.90	£29.10	£14.85	£48.03	£10.38	£8.37	£3.80	£14.16	£47.40	£9.67	£9.25	£115.06
B2	£15.49	£24.16	£11.58	£37.79	£5.80	£7.21	£3.80	£9.05	£35.95	£4.74	£5.80	£88.01
B3	£15.39	£24.09	£11.52	£37.55	£5.76	£7.20	£3.80	£8.95	£35.67	£4.68	£5.74	£87.60
C1	£19.29	£26.45	£13.78	£44.29	£7.97	£6.51	£3.80	£10.90	£39.99	£7.29	£9.25	£101.44
C2	£14.76	£22.49	£11.08	£35.52	£3.95	£6.51	£3.80	£8.05	£33.92	£4.13	£5.80	£81.61
C3	£14.66	£22.41	£11.03	£35.28	£3.97	£6.51	£3.80	£8.00	£33.73	£4.09	£5.74	£81.24
D1	£19.29	£26.45	£13.54	£43.86	£7.97	£5.88	£3.80	£10.90	£37.82	£7.29	£9.25	£99.07
D2	£14.05	£21.88	£10.15	£32.46	£3.95	£5.17	£3.80	£6.52	£29.13	£4.13	£5.80	£75.03
D3	£13.95	£21.80	£10.10	£32.21	£3.97	£5.17	£3.80	£7.19	£29.74	£4.09	£5.74	£74.64

Detailed output of QB coordination framework

This section includes part of the detailed output of the QB coordination framework for the example of section 5.3.3.2.

Figure App-12: Preventive SC-OPF output. Strategy B1 dispatch period 1408 (final iteration)

```
Dispatch period: 1408
Preventive SCOPF
secured to post-fault continuous:
60004      PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4
60042      ECCL4   -STEW4/ECCL4   -STEW4
60151      STEW4   -DRAX4/STEW4   -DRAX4
60056      PEWO4_Q2-DRAX4/        -
secured to post-fault short term (20 min):
60005      PEWO4_Q2-DRAX4/DAIN4-DRAX4
60006      PEWO4_Q1-DAIN4/DAIN4-DRAX4
60038      PEWO4   -MERS4/PEWO4-MERS4
60040      HARK4   -PEWO4/HARK4-PEWO4
60041      STHA4   -HARK4/STHA4-HARK4
60049      STEW4   -DRAX4/     -
60050      STEW4   -DRAX4/     -
60055      PEWO4_Q1-DAIN4/     -
60070      DRAX4   -KEAD4/     -
60071      DRAX4   -KEAD4/     -
60120      STHA4   -HARK4/     -
60121      STHA4   -HARK4/     -
60130      TORN4   -ECCL4/     -
60131      TORN4   -ECCL4/     -
Unrestricted flows
   B6 OHL: 6540.54 MW
   B6 DC_link: 2000.00 MW
Restricted flows
   B6 OHL: 3235.60 MW
   B6 DC_link: 2000.00 MW

Bid off: -3304.94 MW; Offered on: 3304.94 MW
fval: 12207.509
       Type       P_Offer                  P_Bid
    __________    _______    __________    _______

    'CHP'          354.1                   -293.15
    'CCGT'          1527                         0
    'Hydro'            0                   -332.45
```

'OnWind'	0	-2679.3
'penaltyO'	1423.9	0

FnKey	Node	GenType	PMIN	PG	PMAX	PG_final	P_Offer	C_Offer	P_Bid	C_Bid
30005	'BEAU4'	'Hydro'	0	162.59	670	0	0	0	-162.59	5625.5
30009	'BEAU4'	'OnWind'	0	2526.7	2680	1260.1	0	0	-1266.7	56367
30031	'ERRO4'	'Hydro'	0	169.87	700	0	0	0	-169.87	5877.4
30042	'BONN4'	'CHP'	0	77.599	90	0	0	0	-77.599	-550.96
30068	'STHA4'	'CHP'	0	215.55	250	0	0	0	-215.55	-1530.4
30087	'TORN4'	'OnWind'	0	1412.7	1513	0	0	0	-1412.7	62863
30120	'STEW4'	'CHP'	0	439.73	510	510	70.27	3506.5	0	0
30133	'PEWO4'	'CHP'	0	267.29	310	310	42.713	2131.4	0	0
30198	'KEAD4'	'CHP'	0	163.82	190	190	26.179	1306.3	0	0
30224	'FECK4'	'CHP'	0	353.51	410	410	56.491	2818.9	0	0
30263	'PELH4'	'CHP'	0	73.288	85	85	11.712	584.41	0	0
30276	'ECLA4'	'CHP'	0	73.288	85	85	11.712	584.41	0	0
30289	'MELK4'	'CHP'	0	129.33	150	150	20.668	1031.3	0	0
30314	'LOND4'	'CCGT'	0	387.48	1190	1190	802.52	46867	0	0
30315	'LOND4'	'CHP'	0	250.04	290	290	39.957	1993.9	0	0
30327	'GRAI4'	'CCGT'	0	2075.6	2800	2800	724.44	42308	0	0
30354	'LOVE4'	'CHP'	0	232.8	270	270	37.202	1856.4	0	0
30380	'MERS4'	'CHP'	0	232.8	270	270	37.202	1856.4	0	0
30399	'STEW4'	'penaltyO'	0	1	600	352.21	351.21	1.7561e+05	0	0
30403	'STSB4'	'penaltyO'	0	1	600	474.66	473.66	2.3683e+05	0	0
30404	'DRAX4'	'penaltyO'	0	1	600	600	599	2.995e+05	0	0

FnKey	Node1	Node2	Type	RATE_A	PF_init	loading_init	PF_final	loading_final	PF_change
20007	'PEWO4_Q1'	'DAIN4'	'LINE'	2420	2003	82.769	1647.7	68.086	355.32
20008	'PEWO4_Q2'	'DRAX4'	'LINE'	2420	1830.3	75.634	1492.6	61.678	337.74
20001	'STEW4'	'DRAX4'	'LINE'	2000	1744.3	87.215	1214.5	60.724	529.82
20002	'STEW4'	'DRAX4'	'LINE'	2000	1744.3	87.215	1214.5	60.724	529.82

Over_branch	Case_FnKey	Case	Over_MW
"TORN4 -ECCL4"	60130	"TORN4 -ECCL4/ - "	1163.1
""	60041	"STHA4 -HARK4/STHA4 -HARK4"	931.53
"STHA4 -HARK4"	60042	"ECCL4 -STEW4/ECCL4 -STEW4"	1100.8
""	60121	"STHA4 -HARK4/ - "	190.21
"STHA4 -HARK4"	60042	"ECCL4 -STEW4/ECCL4 -STEW4"	1100.8
""	60120	"STHA4 -HARK4/ - "	190.21

```
"STEW4   -DRAX4"    60151         "STEW4   -DRAX4/STEW4   -DRAX4"    872.28
""                  60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    184.41
""                  60050         "STEW4   -DRAX4/        -     "    178.23
""                  60040         "HARK4   -PEWO4/HARK4   -PEWO4"    125.27
""                      1         "        -     /        -     "    64.792
""                  60041         "STHA4   -HARK4/STHA4   -HARK4"    29.265
"STEW4   -DRAX4"    60151         "STEW4   -DRAX4/STEW4   -DRAX4"    872.28
""                  60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    184.41
""                  60049         "STEW4   -DRAX4/        -     "    178.23
""                  60040         "HARK4   -PEWO4/HARK4   -PEWO4"    125.27
""                      1         "        -     /        -     "    64.792
""                  60041         "STHA4   -HARK4/STHA4   -HARK4"    29.265
"STEW4   -HARK4"    60042         "ECCL4   -STEW4/ECCL4   -STEW4"    773.61
""                  60040         "HARK4   -PEWO4/HARK4   -PEWO4"    389.45
""                  60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    327.98
"TORN4   -ECCL4"    60131         "TORN4   -ECCL4/        -     "    739.34
""                  60041         "STHA4   -HARK4/STHA4   -HARK4"    507.73
"PEWO4_Q1-DAIN4"    60056         "PEWO4_Q2-DRAX4/        -     "    458.84
""                  60005         "PEWO4_Q2-DRAX4/DAIN4   -DRAX4"    223.12
""                  60042         "ECCL4   -STEW4/ECCL4   -STEW4"    220.03
""                  60038         "PEWO4   -MERS4/PEWO4   -MERS4"    20.546
"STEW4   -HARK4"    60042         "ECCL4   -STEW4/ECCL4   -STEW4"    389.86
""                  60040         "HARK4   -PEWO4/HARK4   -PEWO4"    77.154
""                  60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    71.166
"PEWO4   -MERS4"    60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    339.69
"PEWO4   -MERS4"    60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    339.69
"DRAX4   -KEAD4"    60071         "DRAX4   -KEAD4/        -     "    245.69
"DRAX4   -KEAD4"    60070         "DRAX4   -KEAD4/        -     "    245.69
"PEWO4_Q2-DRAX4"    60042         "ECCL4   -STEW4/ECCL4   -STEW4"    238.81
""                  60055         "PEWO4_Q1-DAIN4/        -     "    157.06
""                  60006         "PEWO4_Q1-DAIN4/DAIN4   -DRAX4"    74.003
"ECCL4   -STEW4"    60041         "STHA4   -HARK4/STHA4   -HARK4"    168.37
"ECCL4   -STEW4"    60041         "STHA4   -HARK4/STHA4   -HARK4"    168.37

          Case                 Active_constraints    Shadow_price
_________________________    __________________    ____________

"ECCL4-STEW4/ECCL4-STEW4"    "STEW4-HARK4"         2387.7
"STEW4-DRAX4/STEW4-DRAX4"    "STEW4-DRAX4"         225.41
```

Figure App-13: Preventive SC-OPF output. Strategy C1 dispatch period 1408 (final iteration)

```
----------------------------------------------------------------------------------
Dispatch period: 1408
Preventive SCOPF
secured to post-fault continuos:
60004      PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4
60151      STEW4   -DRAX4/STEW4   -DRAX4
secured to post-fault short term (20 min):
60005      PEWO4_Q2-DRAX4/DAIN4-DRAX4
60006      PEWO4_Q1-DAIN4/DAIN4-DRAX4
60038      PEWO4   -MERS4/PEWO4-MERS4
60040      HARK4   -PEWO4/HARK4-PEWO4
60041      STHA4   -HARK4/STHA4-HARK4
60042      ECCL4   -STEW4/ECCL4-STEW4
60049      STEW4   -DRAX4/     -
60050      STEW4   -DRAX4/     -
60055      PEWO4_Q1-DAIN4/     -
60056      PEWO4_Q2-DRAX4/     -
60070      DRAX4   -KEAD4/     -
60071      DRAX4   -KEAD4/     -
60120      STHA4   -HARK4/     -
60121      STHA4   -HARK4/     -
60130      TORN4   -ECCL4/     -
60131      TORN4   -ECCL4/     -
Unrestricted flows
   B6 OHL: 6540.54 MW
   B6 DC_link: 2000.00 MW
Restricted flows
   B6 OHL: 3522.11 MW
   B6 DC_link: 2000.00 MW

Bid off: -3018.43 MW; Offered on: 3018.43 MW
fval: 10410.494
       Type       P_Offer                  P_Bid
    __________    _______    __________    _______

    'CHP'          354.1                   -293.15
    'CCGT'          1527                         0
    'Hydro'            0                   -332.45
    'OnWind'           0                   -2392.8
    'penaltyO'    1137.4                         0

    FnKey     Node       GenType      PMIN       PG       PMAX    PG_final     P_Offer     C_Offer       P_Bid      C_Bid
```

30005	'BEAU4'	'Hydro'	0	162.59	670	0	0	0	-162.59	5625.5
30009	'BEAU4'	'OnWind'	0	2526.7	2680	2228.4	0	0	-298.38	13278
30031	'ERRO4'	'Hydro'	0	169.87	700	0	0	0	-169.87	5877.4
30042	'BONN4'	'CHP'	0	77.599	90	0	0	0	-77.599	-550.96
30068	'STHA4'	'CHP'	0	215.55	250	0	0	0	-215.55	-1530.4
30074	'STHA4'	'OnWind'	0	2742.2	2937	2060.4	0	0	-681.79	30339
30087	'TORN4'	'OnWind'	0	1412.7	1513	0	0	0	-1412.7	62863
30120	'STEW4'	'CHP'	0	439.73	510	510	70.27	3506.5	0	0
30133	'PEWO4'	'CHP'	0	267.29	310	310	42.713	2131.4	0	0
30198	'KEAD4'	'CHP'	0	163.82	190	190	26.179	1306.3	0	0
30224	'FECK4'	'CHP'	0	353.51	410	410	56.491	2818.9	0	0
30263	'PELH4'	'CHP'	0	73.288	85	85	11.712	584.41	0	0
30276	'ECLA4'	'CHP'	0	73.288	85	85	11.712	584.41	0	0
30289	'MELK4'	'CHP'	0	129.33	150	150	20.668	1031.3	0	0
30314	'LOND4'	'CCGT'	0	387.48	1190	1190	802.52	46867	0	0
30315	'LOND4'	'CHP'	0	250.04	290	290	39.957	1993.9	0	0
30327	'GRAI4'	'CCGT'	0	2075.6	2800	2800	724.44	42308	0	0
30354	'LOVE4'	'CHP'	0	232.8	270	270	37.202	1856.4	0	0
30380	'MERS4'	'CHP'	0	232.8	270	270	37.202	1856.4	0	0
30399	'STEW4'	'penaltyO'	0	1	600	99.712	98.712	49356	0	0
30403	'STSB4'	'penaltyO'	0	1	600	440.65	439.65	2.1982e+05	0	0
30404	'DRAX4'	'penaltyO'	0	1	600	600	599	2.995e+05	0	0

FnKey	Node1	Node2	Type	RATE_A	PF_init	loading_init	PF_final	loading_final	PF_change
20007	'PEWO4_Q1'	'DAIN4'	'LINE'	2420	2003	82.769	1659.7	68.581	343.33
20008	'PEWO4_Q2'	'DRAX4'	'LINE'	2420	1830.3	75.634	1507.5	62.295	322.81
20001	'STEW4'	'DRAX4'	'LINE'	2000	1744.3	87.215	1214.5	60.724	529.82
20002	'STEW4'	'DRAX4'	'LINE'	2000	1744.3	87.215	1214.5	60.724	529.82

Over_branch	Case_FnKey	Case	Over_MW
"TORN4 -ECCL4"	60130	"TORN4 -ECCL4/ - "	1163.1
""	60041	"STHA4 -HARK4/STHA4 -HARK4"	931.53
"STEW4 -DRAX4"	60151	"STEW4 -DRAX4/STEW4 -DRAX4"	872.28
""	60004	"PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"	184.41
""	60050	"STEW4 -DRAX4/ - "	178.23
""	60040	"HARK4 -PEWO4/HARK4 -PEWO4"	125.27
""	1	" - / - "	64.792
""	60041	"STHA4 -HARK4/STHA4 -HARK4"	29.265
"STEW4 -DRAX4"	60151	"STEW4 -DRAX4/STEW4 -DRAX4"	872.28

```
    ""                 60004        "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    184.41
    ""                 60049        "STEW4   -DRAX4/        -     "    178.23
    ""                 60040        "HARK4   -PEWO4/HARK4   -PEWO4"    125.27
    ""                     1        "        -     /        -     "    64.792
    ""                 60041        "STHA4   -HARK4/STHA4   -HARK4"    29.265
    "STHA4   -HARK4"   60042        "ECCL4   -STEW4/ECCL4   -STEW4"    840.37
    ""                 60121        "STHA4   -HARK4/        -     "    190.21
    "STHA4   -HARK4"   60042        "ECCL4   -STEW4/ECCL4   -STEW4"    840.37
    ""                 60120        "STHA4   -HARK4/        -     "    190.21
    "TORN4   -ECCL4"   60131        "TORN4   -ECCL4/        -     "    739.34
    ""                 60041        "STHA4   -HARK4/STHA4   -HARK4"    507.73
    "STEW4   -HARK4"   60042        "ECCL4   -STEW4/ECCL4   -STEW4"    696.66
    ""                 60040        "HARK4   -PEWO4/HARK4   -PEWO4"    389.45
    ""                 60004        "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    327.98
    "PEWO4   -MERS4"   60004        "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    339.69
    "PEWO4   -MERS4"   60004        "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    339.69
    "STEW4   -HARK4"   60042        "ECCL4   -STEW4/ECCL4   -STEW4"    296.86
    ""                 60040        "HARK4   -PEWO4/HARK4   -PEWO4"    77.154
    ""                 60004        "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    71.166
    "DRAX4   -KEAD4"   60071        "DRAX4   -KEAD4/        -     "    245.69
    "DRAX4   -KEAD4"   60070        "DRAX4   -KEAD4/        -     "    245.69
    "PEWO4_Q1-DAIN4"   60056        "PEWO4_Q2-DRAX4/        -     "    241.04
    ""                 60005        "PEWO4_Q2-DRAX4/DAIN4   -DRAX4"    223.12
    ""                 60038        "PEWO4   -MERS4/PEWO4   -MERS4"    20.546
    ""                 60042        "ECCL4   -STEW4/ECCL4   -STEW4"    2.2274
    "ECCL4   -STEW4"   60041        "STHA4   -HARK4/STHA4   -HARK4"    168.37
    "ECCL4   -STEW4"   60041        "STHA4   -HARK4/STHA4   -HARK4"    168.37
    "PEWO4_Q2-DRAX4"   60055        "PEWO4_Q1-DAIN4/        -     "    157.06
    ""                 60006        "PEWO4_Q1-DAIN4/DAIN4   -DRAX4"    74.003
    ""                 60042        "ECCL4   -STEW4/ECCL4   -STEW4"    21.015

                 Case                  Active_constraints    Shadow_price
    _______________________________    __________________    ____________

    "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    "PEWO4-MERS4"         272.22
    "STEW4   -DRAX4/STEW4   -DRAX4"    "STEW4-DRAX4"         196.67
    "ECCL4   -STEW4/ECCL4   -STEW4"    "STEW4-HARK4"         2294.4

-----------------------------------------------------------------------------------
```

Figure App -14: Preventive SC-OPF output. Strategy D1 dispatch period 1408 (final iteration)

```
-----------------------------------------------------------------------------------
Dispatch period: 1408
Preventive SCOPF
secured to post-fault continuous:
60004      PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4
secured to post-fault short term (20 min):
60005      PEWO4_Q2-DRAX4/DAIN4-DRAX4
60006      PEWO4_Q1-DAIN4/DAIN4-DRAX4
60038      PEWO4   -MERS4/PEWO4-MERS4
60040      HARK4   -PEWO4/HARK4-PEWO4
60041      STHA4   -HARK4/STHA4-HARK4
60042      ECCL4   -STEW4/ECCL4-STEW4
60151      STEW4   -DRAX4/STEW4-DRAX4
60049      STEW4   -DRAX4/     -
60050      STEW4   -DRAX4/     -
60055      PEWO4_Q1-DAIN4/     -
60056      PEWO4_Q2-DRAX4/     -
60070      DRAX4   -KEAD4/     -
60071      DRAX4   -KEAD4/     -
60120      STHA4   -HARK4/     -
60121      STHA4   -HARK4/     -
60130      TORN4   -ECCL4/     -
60131      TORN4   -ECCL4/     -
Unrestricted flows
   B6 OHL: 6540.54 MW
   B6 DC_link: 2000.00 MW
Restricted flows
   B6 OHL: 3578.56 MW
   B6 DC_link: 2000.00 MW

Bid off: -2961.98 MW; Offered on: 2961.98 MW
fval: 10056.487
       Type       P_Offer                  P_Bid
    __________    _______    __________    _______

    'CHP'          354.1                   -293.15
    'CCGT'          1527                         0
    'Hydro'            0                   -332.45
    'OnWind'           0                   -2336.4
    'penaltyO'    1080.9                         0

    FnKey     Node       GenType      PMIN      PG       PMAX    PG_final    P_Offer     C_Offer       P_Bid      C_Bid
```

30005	'BEAU4'	'Hydro'	0	162.59	670	0	0	0	-162.59	5625.5
30031	'ERRO4'	'Hydro'	0	169.87	700	0	0	0	-169.87	5877.4
30042	'BONN4'	'CHP'	0	77.599	90	0	0	0	-77.599	-550.96
30068	'STHA4'	'CHP'	0	215.55	250	0	0	0	-215.55	-1530.4
30074	'STHA4'	'OnWind'	0	2742.2	2937	1495.2	0	0	-1247.1	55494
30087	'TORN4'	'OnWind'	0	1412.7	1513	323.33	0	0	-1089.3	48475
30120	'STEW4'	'CHP'	0	439.73	510	510	70.27	3506.5	0	0
30133	'PEWO4'	'CHP'	0	267.29	310	310	42.713	2131.4	0	0
30198	'KEAD4'	'CHP'	0	163.82	190	190	26.179	1306.3	0	0
30224	'FECK4'	'CHP'	0	353.51	410	410	56.491	2818.9	0	0
30263	'PELH4'	'CHP'	0	73.288	85	85	11.712	584.41	0	0
30276	'ECLA4'	'CHP'	0	73.288	85	85	11.712	584.41	0	0
30289	'MELK4'	'CHP'	0	129.33	150	150	20.668	1031.3	0	0
30314	'LOND4'	'CCGT'	0	387.48	1190	1190	802.52	46867	0	0
30315	'LOND4'	'CHP'	0	250.04	290	290	39.957	1993.9	0	0
30327	'GRAI4'	'CCGT'	0	2075.6	2800	2800	724.44	42308	0	0
30354	'LOVE4'	'CHP'	0	232.8	270	270	37.202	1856.4	0	0
30380	'MERS4'	'CHP'	0	232.8	270	270	37.202	1856.4	0	0
30399	'STEW4'	'penaltyO'	0	1	600	426.15	425.15	2.1257e+05	0	0
30403	'STSB4'	'penaltyO'	0	1	600	57.768	56.768	28384	0	0
30404	'DRAX4'	'penaltyO'	0	1	600	600	599	2.995e+05	0	0

FnKey	Node1	Node2	Type	RATE_A	PF_init	loading_init	PF_final	loading_final	PF_change
20007	'PEWO4_Q1'	'DAIN4'	'LINE'	2420	2003	82.769	1662.2	68.685	340.84
20001	'STEW4'	'DRAX4'	'LINE'	2000	1744.3	87.215	1323.8	66.19	420.49
20002	'STEW4'	'DRAX4'	'LINE'	2000	1744.3	87.215	1323.8	66.19	420.49
20008	'PEWO4_Q2'	'DRAX4'	'LINE'	2420	1830.3	75.634	1503.4	62.126	326.9

Over_branch	Case_FnKey	Case	Over_MW
"TORN4 -ECCL4"	60130	"TORN4 -ECCL4/ - "	1163.1
""	60041	"STHA4 -HARK4/STHA4 -HARK4"	931.53
"STHA4 -HARK4"	60042	"ECCL4 -STEW4/ECCL4 -STEW4"	840.37
""	60121	"STHA4 -HARK4/ - "	190.21
"STHA4 -HARK4"	60042	"ECCL4 -STEW4/ECCL4 -STEW4"	840.37
""	60120	"STHA4 -HARK4/ - "	190.21
"TORN4 -ECCL4"	60131	"TORN4 -ECCL4/ - "	739.34
""	60041	"STHA4 -HARK4/STHA4 -HARK4"	507.73
"STEW4 -HARK4"	60042	"ECCL4 -STEW4/ECCL4 -STEW4"	696.66
""	60040	"HARK4 -PEWO4/HARK4 -PEWO4"	389.45

```
    ""                  60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    327.98
    "STEW4   -DRAX4"    60151         "STEW4   -DRAX4/STEW4   -DRAX4"    692.28
    ""                  60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    184.41
    ""                  60050         "STEW4   -DRAX4/        -     "    178.23
    ""                  60040         "HARK4   -PEWO4/HARK4   -PEWO4"    125.27
    ""                      1         "        -     /        -     "    64.792
    ""                  60041         "STHA4   -HARK4/STHA4   -HARK4"    29.265
    "STEW4   -DRAX4"    60151         "STEW4   -DRAX4/STEW4   -DRAX4"    692.28
    ""                  60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    184.41
    ""                  60049         "STEW4   -DRAX4/        -     "    178.23
    ""                  60040         "HARK4   -PEWO4/HARK4   -PEWO4"    125.27
    ""                      1         "        -     /        -     "    64.792
    ""                  60041         "STHA4   -HARK4/STHA4   -HARK4"    29.265
    "PEWO4   -MERS4"    60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    339.69
    "PEWO4   -MERS4"    60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    339.69
    "STEW4   -HARK4"    60042         "ECCL4   -STEW4/ECCL4   -STEW4"    296.86
    ""                  60040         "HARK4   -PEWO4/HARK4   -PEWO4"    77.154
    ""                  60004         "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    71.166
    "DRAX4   -KEAD4"    60071         "DRAX4   -KEAD4/        -     "    245.69
    "DRAX4   -KEAD4"    60070         "DRAX4   -KEAD4/        -     "    245.69
    "PEWO4_Q1-DAIN4"    60056         "PEWO4_Q2-DRAX4/        -     "    241.04
    ""                  60005         "PEWO4_Q2-DRAX4/DAIN4   -DRAX4"    223.12
    ""                  60038         "PEWO4   -MERS4/PEWO4   -MERS4"    20.546
    ""                  60042         "ECCL4   -STEW4/ECCL4   -STEW4"    2.2274
    "ECCL4   -STEW4"    60041         "STHA4   -HARK4/STHA4   -HARK4"    168.37
    "ECCL4   -STEW4"    60041         "STHA4   -HARK4/STHA4   -HARK4"    168.37
    "PEWO4_Q2-DRAX4"    60055         "PEWO4_Q1-DAIN4/        -     "    157.06
    ""                  60006         "PEWO4_Q1-DAIN4/DAIN4   -DRAX4"    74.003
    ""                  60042         "ECCL4   -STEW4/ECCL4   -STEW4"    21.015

                 Case                 Active_constraints    Shadow_price
    _______________________________    __________________    ____________

    "PEWO4_Q1-DAIN4/PEWO4_Q2-DRAX4"    "PEWO4-MERS4"         272.22
    "ECCL4   -STEW4/ECCL4   -STEW4"    "STEW4-HARK4"         2294.4
    "STEW4   -DRAX4/STEW4   -DRAX4"    "STEW4-DRAX4"         196.67

  ---------------------------------------------------------------------------------
```

Figure App -15: Post-Contingency OPF: Strategy C1 Dispatch period 1408 Contingency 60042 (second framework iteration)

```
----------------------------------------------------------------------------------
Post-contingency OPF 2
----------------------------------------------------------------------------------
Dispatch period: 1408
Post-contingency OPF
obj:  min cost of control actions
maxQBmoves 2 maxBidmoves 2 maxOffermoves 3
60042      ECCL4-STEW4/ECCL4-STEW4
Unrestricted flows
   B6 OHL: 3522.11 MW
   B6 DC_link: 2000.00 MW
Restricted flows
   B6 OHL: 3522.11 MW
   B6 DC_link: 2000.00 MW

Bid off: 0.00 MW; Offered on: 0.00 MW
Cost: £ 0.00
fval: 8.547
     Node1       Node2       Type    TAP_init    TAP_final     D_TAP
    _______    __________    ____    ________    _________    _______

    'PEWO4'    'PEWO4_Q1'    'QB'    0           -4.2734      -4.2734
    'PEWO4'    'PEWO4_Q2'    'QB'    0           -4.2734      -4.2734

    FnKey      Node1         Node2      Type     RATE_A    PF_init    loading_init    PF_final    loading_final    PF_change
    _____    __________    _______    ______    ______    _______    ____________    ________    _____________    __________

    20004    'STEW4'       'HARK4'    'LINE'     855      -931.45    108.94          -854.5      99.942                76.95
    20007    'PEWO4_Q1'    'DAIN4'    'LINE'    2420       2008.6        83          2206.9      91.196               198.34
    20008    'PEWO4_Q2'    'DRAX4'    'LINE'    2420       1961.4    81.051          2158.2      89.182               196.77
    20091    'STHA4'       'HARK4'    'LINE'    2170       1761.1    81.155          1761.1      81.155           4.3201e-12
    20092    'STHA4'       'HARK4'    'LINE'    2170       1761.1    81.155          1761.1      81.155           4.3201e-12

     Over_branch     Case_FnKey              Case              Over_MW
    _____________    __________    _________________________    _______

    "STEW4-HARK4"    60042         "ECCL4-STEW4/ECCL4-STEW4"    76.95

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```

Figure App -16: Post-Contingency OPF: Strategy D1 Dispatch period 1408 Contingency 60151 (second framework iteration)

```
-----------------------------------------------------------------------------------
Post-contingency OPF 2
-----------------------------------------------------------------------------------
Dispatch period: 1408
Post-contingency OPF
obj:  min cost of control actions
maxQBmoves  maxBidmoves 2 maxOffermoves 3
60151      STEW4-DRAX4/STEW4-DRAX4
Unrestricted flows
   B6 OHL: 3578.56 MW
   B6 DC_link: 2000.00 MW
Restricted flows
   B6 OHL: 3578.56 MW
   B6 DC_link: 2000.00 MW

Bid off: -13.12 MW; Offered on: 13.12 MW
fval: 65.464
     Node1       Node2       Type    TAP_init    TAP_final    D_TAP
    _______    __________    ____    ________    _________    _____

    'PEWO4'    'PEWO4_Q1'    'QB'    0           -7           -7
    'PEWO4'    'PEWO4_Q2'    'QB'    0           -7           -7
    'DEES4'    'DEES4_Q1'    'QB'    0           -7           -7
    'DEES4'    'DEES4_Q2'    'QB'    0           -7           -7
    'STSB4'    'STSB4_Q1'    'QB'    0            7            7
    'KEAD4'    'KEAD4_Q1'    'QB'    0            7            7
    'KEAD4'    'KEAD4_Q2'    'QB'    0            7            7

    Type     P_Offer               P_Bid
    _____    _______    _______    _______

    'CHP'    13.119                -13.119

    FnKey     Node       GenType    PMIN      PG       PMAX    PG_final    P_Offer    C_Offer    P_Bid      C_Bid
    _____    _______    _______    ____    ______    ____    ________    _______    _______    _______    _______

    30120    'STEW4'    'CHP'      0          510     510    496.88            0          0    -13.119    -93.145
    30237    'WALP4'    'CHP'      0       8.6222      10        10       1.3778     68.754          0          0
    30250    'BRFO4'    'CHP'      0       25.866      30        30       4.1335     206.26          0          0
    30328    'GRAI4'    'CHP'      0       51.733      60    59.341       7.6076     379.62          0          0

    FnKey      Node1         Node2       Type      RATE_A    PF_init    loading_init    PF_final    loading_final    PF_change
```

20001	'STEW4'	'DRAX4'	'LINE'	2000	2179.5	108.97	1999.5	99.975	180
20002	'STEW4'	'DRAX4'	'LINE'	2000	2179.5	108.97	1999.5	99.975	180
20007	'PEWO4_Q1'	'DAIN4'	'LINE'	2420	1761	72.767	2104.4	86.961	343.49
20008	'PEWO4_Q2'	'DRAX4'	'LINE'	2420	1631.9	67.436	1737.4	71.792	105.42

Over_branch	Case_FnKey	Case	Over_MW
"STEW4-DRAX4"	60151	"STEW4-DRAX4/STEW4-DRAX4"	180
"STEW4-DRAX4"	60151	"STEW4-DRAX4/STEW4-DRAX4"	180

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