# A Multi-Objective Transmission Reinforcement Planning Approach for Analysing Future Energy Scenarios in the GB Network

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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.

*To my wife Kirsty, my daughter Ella, and my parents Mary and Michael Barnacle*

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# Abbreviations, Acronyms and Technical Terms

| | |
|---|---|
| AC | Alternating Current |
| ACPF | AC Power Flow |
| ACS Condition | The Average Cold Spell condition is a combination of weather elements which give rise to a level of peak demand within a financial year (1st April to 31st March) which has a 50% chance of being exceeded due to weather variation alone. |
| AGR | Advanced Gas-cooled Reactor |
| APR | Advanced Power Reactor |
| BETTA | British Electricity Trading and Transmission Arrangements |
| BM | Balancing Mechanism |
| CAPEX | Capital Expenditure |
| CCGT | Combined Cycle Gas Turbine |
| CCS | Carbon Capture and Storage |
| CfD | Contract for Difference |
| CHP | Combined Heat and Power |
| DC | Direct Current |
| DCPF | DC Power Flow |
| DCOPF | DC Optimal Power Flow |
| EA | Evolutionary Algorithm |
| Embedded Generation | Electricity generating plant connected to the distribution network. |
| EPR | European Pressurised Reactor (sometimes marketed as an Evolutionary Power Reactor) |
| EPTC | Economy Planned Transfer Condition |
| ETYS | Electricity Ten Year Statement |
| EU | European Union |
| GA | Genetic Algorithm |
| GB | Great Britain |
| GW | Gigawatt |
| HV | High Voltage |
| HVAC | High Voltage Alternating Current |
| HVDC | High Voltage Direct Current |
| IED | Industrial Emissions Directive |

| | |
|---|---|
| km | Kilometre |
| kV | Kilovolt |
| LCPD | Large Combustion Plant Directive |
| LDC | Load Duration Curve |
| LV | Low Voltage |
| MITS | Main Interconnected Transmission System |
| MOEA | Multi-objective Evolutionary Algorithm |
| MOTEP | Multi-objective Transmission Expansion Planning |
| MOTREP | Multi-objective Transmission Reinforcement Planning |
| MVA | Mega-volt amperes |
| MW | Mega-watt |
| MWh | Mega-watt hour |
| MX | Magnox |
| NETS | National Electricity Transmission System |
| NGET | National Grid Electricity Transmission (plc) |
| OCGT | Open Cycle Gas Turbine |
| OFTO | Offshore Transmission Owner |
| OHL | Overhead Line |
| RO | Renewable Obligation |
| SHE-T | Scottish Hydro Electric Transmission Limited |
| SO | System Operator |
| SPT | Scottish Power Transmission (plc) |
| SQSS | Security and Quality of Supply Standard |
| SYS | Seven Year Statement |
| TEC | Transmission Entry Capacity |
| TEP | Transmission Expansion Planning |
| Thermal Overload | Thermal loading above the capacity of the line. |
| Thermal Violation | Thermal loading above a pre-defined power flow condition. |
| TRP | Transmission Reinforcement Plan |
| TNO | Transmission Network Owner |
| TNUoS Charges | Transmission Network Use of System Charges |
| UGC | Underground Cable |
| UK | United Kingdom |

# Abstract

Due to increasing worldwide environmental concern, the United Kingdom (UK) government, under the Climate Change Act (2008), has set a target of at least an 80% reduction in the net UK carbon account, from baseline 1990 levels, by 2050. Recently there has been a rise in the number of low-carbon policy related studies, creating a growing number of national energy scenarios, some of which achieve the emission targets for 2050.

A key aspect of evaluating the technical and economic impact of these energy scenarios is in assessing the associated effect on the electrical transmission network. As a result of a new scenario-related generation background, network limitations are likely to occur on the system. By creating a transmission reinforcement plan to alleviate these network issues, a conclusion can be made as to the economic impact of a future scenario to the electrical transmission network; thereby aiding the overall assessment of the scenario. However, by its nature the transmission planning problem is multi-objective with multiple economic conflicts. For a reinforcement designed for the main interconnected transmission system to gain economic approval from the network regulator, the reinforcement needs to alleviate annual network congestion such that the cost savings associated are greater than the capital expenditure and maintenance costs of the project. Further, this reinforcement will need to be established with minimal outages to existing network assets.

This thesis proposes a flexible framework to evaluate the thermal and economic effect of applying a future energy scenario to the GB network. This is achieved through locating an optimal set of transmission reinforcement plans for the multi-criteria problem outlined above. The framework utilises a novel systematic algorithm to generate individual reinforcements and overall reinforcement plans for a large-scale multi-voltage network. The systematic algorithm can alter the associated reinforcements should they exacerbate thermal constraints. Specific reinforcements are therefore created for the scenario, and the framework can therefore be used to evaluate a wide range of future scenarios.

The framework is designed to cater for three variations in reinforcement characteristic; location, configuration (line upgrading, single-circuit and double-circuit addition) and thermal capacity. The new framework carries out a thorough exploration of each characteristic and uses a proven multi-objective meta-heuristic technique to perform the optimisation, which can handle complex multi-criteria problems such as transmission network planning effectively.

The reinforcement plans generated are assessed against a stochastic, seasonal evaluation of annual network congestion, which reflects the uncertainty of annual generation output and the impact of planned network outages on annual system constraints. Although meta-heuristic techniques have been successfully applied to solve a variant of the multi-objective transmission planning problem proposed in this thesis, these approaches often simplified the reinforcement characteristics considered and the impact of these reinforcements on the objectives involved, and were often tested against small-scale simplified network backgrounds.

From the frameworks output, a verdict on the economic impact of a future scenario to the electrical transmission network can be made which considers the different perspectives and complexities of the transmission planning problem. By comparing verdicts, a scenario can be located that is the best route forward, from the perspective of the electrical transmission network, to economically meet governmental emission targets. Hence the approach proposed can be used to improve current understanding on the economic impact of a wide range of penetrations in renewable and conventional generation to the network, to guide governmental energy policy and transmission network owner investment. Results from several scenario studies show that the framework is valuable for use in the evaluation of a UK energy scenario which envisions the continuation of a centralised power system.

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# Chapter 1

# 1. Introduction

This chapter introduces the current state of the Great British (GB) electrical transmission network and discusses the need for network reinforcement to enable the future connection of generation. Thereafter the options available for network reinforcement are discussed, a description of the transmission network planning problem is included and the approaches to transmission network planning, and the techniques used for evaluating the network impact of future UK energy scenarios, that motivated this research, are introduced. Further, this chapter outlines the thesis objectives and methodology and details the main contributions of the thesis. The chapter structure of this thesis is then described.

## 1.1. *Thesis Background*

### 1.1.1. The GB Transmission Network and the Need to Reinforce

An electricity transmission network is a high voltage (HV) network designed to carry electricity over long distances, with minimal losses, from large-scale power providers to commercial and domestic users through the more localised medium (MV) and low voltage (LV) electrical distribution network. There are currently three transmission network operators (TNOs), owners and licensees in the GB onshore network, permitted to plan, develop, operate and maintain the high voltage network within their own onshore transmission area, they are; Scottish Hydro Electric Transmission (SHE-T) for northern Scotland and the Scottish Islands, Scottish Power Transmission (SPT) for southern Scotland and National Grid Electricity Transmission (NGET) for England and Wales. Further, National Grid is system operator (SO) for the whole GB transmission network and as such is responsible for ensuring stable and secure operation. The GB transmission network currently consists of around 836 network nodes and 998 transmission lines, 22362km of which are overhead lines (OHLs) and 850km of which are underground cables (UGCs) [1.1]. Three voltage levels exist in the GB transmission network; 400kV, 275kV and 132kV (only in Scotland). The predominant power flow of the GB transmission network is currently from net generation in the north (Scotland) to net demand in the south (England). Figure 1-1 (based on [1.2]) details a simplified pattern

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**Figure 1-1 2011/12 GB Power Flow at ACS peak demand (adapted from [1.2])**

of the power flow experienced at winter peak demand for the average cold spell (ACS) condition in 2011/12.

Since the construction of the 400kV AC network in the 1960s and 1970s, which resulted in the integration of the original 132kV AC transmission lines (constructed throughout the 1930s and 1940s) in England and Wales onto the distribution network, the layout and design of the GB transmission network has seen little change in comparison. The construction of the 275kV AC super-grid in the 1950s reduced network losses making it cheaper to transmit electricity than coal. Hence new generating stations fuelled from coal, the main contributor to electrical demand at the time, were built closer to the fuel source. This approach in combination with new nuclear stations – whose location is restricted by cooling considerations (Nuclear power plants are recommended to be sited within 2km of abundant water [1.3]) – largely dictated the design of the 400kV network. Despite the layout of the GB transmission network being largely unchanged for this length of time, the transmission system has operated with a very high reliability that has historically fluctuated between 99.9997% and 99.9999% [1.4]. Hence there has been very little interruption in electrical supply due to fault outages of transmission assets; a reliability that needs to be maintained due partly to the present expectation of service from network users.

With the emergence of the Large Combustion Plant Directive (LCPD) in 2001 due to increased environmental concern – which includes legislative limits on emissions from combustion plants that have a capacity of 50MW or greater [1.5] – several coal and oil fuelled plants, that have refused to comply with the LCPD (now part of the Industrial Emissions Directive), were forced to close by 2015. This has resulted in a loss of 11,358MW of generation to the grid [1.6], which equates to around 20% of peak electrical demand[1]. This capacity needs to be replaced to maintain network security and reliability. To meet legally binding government environmental targets under the Climate Change Act (2008) – which aims to achieve at least an 80% reduction in the net UK carbon account, from baseline 1990 levels by 2050 [1.8] – this electrical capacity is likely to be largely replaced by power from wind, nuclear and natural gas; fuels that result in less output emissions. Particularly regarding wind and nuclear, this results in generation from new locations and therefore necessitates the need to reinforce the GB transmission network.

Electrical generation from wind, both offshore and onshore, produces zero direct emissions of air pollutants and in terms of levelised cost - an economic measure which considers the lifetime costs of a technology – onshore wind turbines are currently the cheapest renewable technology in the UK [1.9]. Also, due to the financial support provided to renewable generation initially through the Renewables Obligation (RO) – which effectively doubled the income for renewable generators [1.9] – and now through Contract for Difference (CfD) agreements [1.10], to provide certainty in investment against a volatile electricity market, wind generation has been on the rise in the UK. In 2015, onshore and offshore wind generation supplied 27%

[1] Calculated assuming a 56.1GW peak demand value which is the Total Gross System Demand (TGSD) registered in 2011/12 [1.7] – TGSD includes the effects of power station demand, pumped storage pumping and exports through interconnectors.

and 21% respectively of total UK wide renewable generation [1.11]; an increase in offshore wind generation from 15% in 2011 and 6% in 2008. As onshore wind farms continue to connect in areas of the network with high local wind speeds (namely Scotland, the north of England and Wales [1.12]), the southerly power flow of the network (as detailed in Figure 1-1) is predicted to increase. This will likely result in increased network strain across crucial transmission circuits required to utilise this renewable generation and meet the bulk of demand from the south of England.

Many wider system reinforcements on the GB main interconnected transmission system have recently been completed or are under construction, following solution design and submission of a 'needs case' by the TNOs, and approval by the UK regulator Ofgem (the Office of Gas and Electricity Markets). These reinforcements have largely been proposed to improve network capability and allow a higher power transfer from the North to the South. Some of these reinforcements are described below [1.14]:

- **Beauly – Denny Overhead Line (OHL) reinforcement**: Replacement of the existing 132kV single-circuit OHL between Beauly (near Inverness in the North of Scotland) and Bonnybridge (near Falkirk in central Scotland) with a higher thermal rated double-circuit OHL capable of 400kV operation (one circuit is operated at 400kV, the other initially at 275kV) that terminates at Denny (also near Falkirk in central Scotland). This OHL is around 220km in length and was fully energised onto the system in 2015.

- **Beauly – Blackhillock – Kintore 275kV OHL Uprate**: Replacement of the conductors on the 275kV double-circuit line between Beauly, Blackhillock (near Keith in the North East of Scotland) and Kintore (South East of Blackhillock and North West of Aberdeen) with new higher capacity conductors. Completed in 2015.

- **Caithness – Moray Reinforcement Strategy**: Installation of a subsea HVDC link across the Moray Firth in the North of Scotland between a new substation at Spittal (in Caithness) and Blackhillock (in Moray). The strategy includes associated onshore works in the Caithness area around the new substation at Spittal and at Dounreay. To be completed in 2018.

- **West Coast HVDC Link:** Installation of a subsea HVDC link between a new 400kV substation in Hunterston (South West of Scotland) to the 400kV substation at Deeside (North Wales). To be completed in 2017.

Whilst these reinforcements are expected to solve many network issues that are predicted to arise from the near term grid connection in Scotland of around 3GW of new transmission contracted generation (substantially made up of wind farms) – the export capability from Scotland to England and Wales would be 3.3GW according to [1.15] – many UK energy scenarios suggest a much greater penetration of renewable generation is required in Scotland to achieve UK environmental targets for 2020 (a 34% reduction in greenhouse gas emissions) and 2050 (an 80% reduction). For example, the 2011 Gone Green scenario, created by National Grid, suggests a requirement of 6.3GW (3.5GW of onshore wind, 2.2GW of offshore wind and 0.6GW of marine generation) in renewable generation connecting by the end of 2020 in SHE-T's area and 3.3GW (2.3GW of onshore wind, 1GW of offshore wind) in SPT's area (see Figure 1-1) [1.15].

In addition, a significant number of large-scale offshore wind farms are to be connected to the England and Wales onshore transmission network. The Crown Estate – landlord and owner of the UK seabed – coordinated a series of licensing 'Rounds' to develop offshore wind generation. Round 1 (launched in 2000) is underway and there are currently 13 projects which are fully operational with a generating capacity of 1.2GW [1.16]. Round 2 (launched in 2003) – locating sites further offshore and into deeper waters – is underway and will add another 6GW of capacity (currently 8 projects are operational with a capacity of 2.4GW [1.16]), and for round 3 (launched in 2010) there is the potential to lease around 33GW of estimated capacity to offshore developers, where construction on some sites has already begun [1.16]. Most offshore wind farm capacity is to connect to the England and Wales onshore transmission network, particularly down the East coast of England (the three largest potential offshore wind farm developments – Dogger Bank, Hornsea and East Anglia – are to connect to this area, amounting to a total of 25GW [1.15]). Areas of this network have yet to be sufficiently reinforced, or have even commenced reinforcement construction to accommodate this level of capacity [1.15]. Hence further network reinforcement of the GB transmission network is required if UK environmental targets for 2020 and particularly 2050 are to be reached.

### 1.1.2. Options for Network Reinforcement

The power transfer capacity of a transmission line may be limited by thermal, voltage or stability criteria. The most common limitation in transmission networks is thermal [1.17], particularly in OHLs. Sufficient clearance between an OHL conductor and objects underneath is required to prevent physical contact or flash over. The required level of minimum clearance depends primarily on the line's voltage and the type of object underneath. A conductor's clearance is dependent on the temperature of the conductor since as the conductor gets hotter, it elongates and sags closer to the ground [1.17]. Hence, a maximum operating conductor temperature is specified for every line in the transmission network, and each line is built high enough to ensure that if the conductor temperature does not exceed this limit, the conductor will not sag beneath the defined level of minimum clearance. As a line's conductor (copper or aluminium) has some electrical resistance, it becomes hotter as more current (and therefore power) flows through it. Therefore, a maximum current – sometimes specified as the line's maximum power in MVA – is used to define the thermal rating of a line. This is the maximum current that can be transferred through a line whilst ensuring that the conductor temperature is below its limit and therefore the conductor itself is above the minimum level of clearance.

Several reinforcement options exist to alleviate network constraints. Options range from line upgrading through reconductoring or re-profiling (which may also be used to enable operation of the line at a higher voltage level), the replacement or addition of a new line, the installation of an offshore subsea HVDC/HVAC cable, or more operational solutions such as generation inter-trip arrangements, the utilisation of dynamic line ratings (based on the pre-fault loading of the line), or the co-ordinated use of Quadrature Booster (QB) schemes (or Phase Shifting Transformers) – which can re-route active power onto lighter loaded lines via direct manipulation of the voltage phase angle between the sending end and receiving end of the line [1.18]. Table 1-1 outlines the reinforcement solutions available to both the SO and TNO, and the associated network constraints which can be alleviated under each option.

Line reconductoring or re-profiling is a lower cost alternative to line construction as the process does not often involve the dismantling and reconstruction of new transmission towers to support the new or existing conductor(s). The thermal rating of the line is thus increased using these methods whilst ensuring that the new or existing conductor(s) are still above the minimum level of clearance defined for the voltage and route of the line. However, there is therefore a limit to the increase in thermal rating able to be achieved from line upgrading, and

**Table 1-1 Reinforcement Solutions for the SO and TNO (source [1.18])**

| Category | Transmission Solution | Constraint | | |
|---|---|---|---|---|
| | | Thermal | Voltage | Stability |
| Low cost-investment | Co-ordinated QB Schemes | x | x | |
| | Auto-switching schemes for alternative running arrangements (automatic open and closing of circuit breakers to reconfigure substations for recognised faults) | x | x | x |
| | Dynamic line ratings (circuits monitored for up to date thermal capabilities) | x | | |
| | Enhanced Generator Reactive range through reactive markets (generators contracted to provide reactive capability beyond their required range) | | x | x |
| | Addition of fast switching equipment for reactive compensation (switching in/out of reactive compensation in response to voltage levels likely to change post-fault) | | x | x |
| | Demand side services (these could involve storage and will allow for peak demand profiling) | x | x | |
| | Protection Changes (faster protection for stability issues, and replacement of protection to improve thermal limitations) | x | | x |
| Operational | Availability Contracts (required to make generation available and more flexible for constraint management) | x | x | x |
| | Intertrip (to trip generation and potentially demand side services for selected planned and/or fault outages) | x | x | x |
| | Reactive Demand Reduction | | x | |
| | Generation advanced control systems (to improve transient stability) | | x | x |
| Investment | Line re-profiling (improve the conductor clearance) | x | | |
| | Line reconductoring or cable replacement | x | | |
| | Reactive Compensation (Capacitor Banks, Static Var Compensators, Reactors) | | x | x |
| | Switchgear Replacement (used to optimise flows) | x | | |
| | New Build (HVAC/HVDC) | x | x | x |

line replacement or addition might be the only options depending upon the severity of the thermal overload and the condition of the existing conductors. Table 1-2 details the advantages and disadvantages identified in the literature of the main higher investment options available for transmission network reinforcement.

The power transfer capacity of a transmission line can also be constrained through a limit in maximum allowable voltage drop. When a transmission line is carrying current, there is a voltage drop in the receiving end voltage from the sending end voltage caused by the line's resistance and inductance [1.20]. This voltage drop increases as the length of the line increases. A typical transmission line has a maximum allowable voltage drop limited to between 5% and 10% of the sending end voltage [1.20]. The power flow (in MVA or MW) that corresponds to the maximum allowable decrease in voltage magnitude is known as the line's voltage drop limit. A transmission line's voltage drop limit decreases as the line length increases and is generally higher than the lines thermal rating for short lines (i.e. less than 50 miles in length)

**Table 1-2 Advantages and Disadvantages of the current main options for Network Reinforcement [1.21]-[1.24]**

| Option | Procedure | Advantages | Disadvantages |
|---|---|---|---|
| Use of Flexible AC Transmission System (FACTS) Devices | Increases power transfer capability of AC transmission lines by adjusting system parameters through series and/or shunt compensation. | • Low maintenance<br>• Aids power flow control, transient stability, voltage stability and control and power oscillation damping<br>• Maximises network throughput and minimises losses in real time. | • Cannot increase the maximum thermal rating of the line<br>• Often needed in parallel with other transmission reinforcement options to meet load growth<br>• High CAPEX – only recent developments in high power electronics have made FACTS devices potentially cost effective |
| Line upgrading through Re-conductoring | Replacement of existing conductor with a higher rated conductor. | • Does not require a new line or line route<br>• No need to change line alignment or notably upgrade substations and transformers<br>• Low CAPEX<br>• No change in maintenance requirement | • May require replacement or foundation strengthening of towers – limits size and capacity of the replacement conductor<br>• Outage of the original line is required during construction<br>• Low effect in reducing network line losses |
| Line upgrading through re-profiling | Re-profiling of the line to improve the clearance of the conductors and enable increased conductor sag. May involve re-tensioning of the conductor and ground excavation works. | Same advantages as with line reconductoring. | Same disadvantages as with line reconductoring. |
| Line replacement or addition of a new line (single-circuit or double-circuit) | Construction of a new line to either replace the existing line, lie adjacent to the existing line, or lie along a new route. Can be operated at a higher voltage level. | • Greater potential effect on network capacity than with line upgrading.<br>• High effect in reducing network line losses<br>• Low outage requirement on the existing network – new line can be connected once constructed | • High CAPEX – will require new towers and significant upgrades to substations and transformers<br>• Increased network maintenance requirement if new line is not a replacement<br>• Could exacerbate network congestion in other areas of the network |
| Addition of an offshore subsea HVDC/HVAC cable | Construction of an offshore underwater HVDC/HVAC cable. Requires converter stations at either end for connection to the onshore AC network. | • Lower line loss and lower CAPEX for long distance conduction in comparison to onshore AC transmission<br>• Can significantly increase network capacity whilst avoiding difficulties with onshore reinforcement | • Offshore HVDC/HVAC is less reliable and has a lower availability than onshore AC transmission; an availability of 97.7% can be achieved for a long HVDC cable (i.e. including cable, converters and transformers) |

but lower, limiting power flow, for HV lines between 50 and 150 miles in length [1.20]. Flexible AC transmission system (FACTS) devices can be used to increase the power transfer capacity of a transmission line limited by its associated voltage drop limit. FACTS devices involve the use of series and/or shunt compensation on the line. To increase a line's voltage drop limit, a shunt capacitor can be connected in parallel at the end of the line [1.20]. This solution is often a cheaper alternative to rebuilding the line.

Many options exist for network reinforcement and each choice has several advantages and disadvantages to the network for the TNO and SO. A network reinforcement planning model should therefore consider as many reinforcement options as possible and evaluate the reinforcements against key economic criteria defined from the associated benefits and drawbacks.

### 1.1.3. Transmission Network Planning

Transmission network planning can be defined as a structured approach to optimise the configuration, location and capacity limits of network reinforcements and/or expansion candidates (i.e. to new network nodes) given a set of objectives and constraints. As identified previously (Table 1-1 and Table 1-2), different options for reinforcing the network exist. Depending upon the reinforcement option, reductions in capital expenditure (CAPEX), network outages (needed to accommodate the reinforcement construction), network maintenance and line losses (along the route) can be achieved. These reductions are benefits to the system however they often conflict. For example, a reduction in CAPEX resulting from the decision to choose line upgrading as opposed to line addition results in an increase in network outages (a line when added can be constructed next to the original line and connected to the network once complete). Further, improved network capability at an increased CAPEX will potentially alleviate more system constraints and the associated cost from buying and selling electricity in the balancing mechanism – a mechanism used by National Grid to ensure the security and quality of electricity supply across the GB transmission system in the event of a transmission constraint – would be reduced. Also, by reinforcing the transmission system to cater for future generation connections, network reliability is maintained.

In the UK, the activities of the TNOs are currently regulated through Ofgem (the Office of Gas and Electricity Markets) via price control periods where the maximum amount of revenue that can be recovered from suppliers, who in turn pass these costs through to customers, is set [1.25]. Through price control, the TNOs are incentivised to improve efficiency and innovate to deliver value for consumers. Hence, to earn a reasonable return over the price control period, the TNO needs to optimally reinforce the network where needed and maximise the use of existing network assets to ensure that consumer demand is met efficiently and securely.

The objectives of transmission reinforcement detailed above (reduction in CAPEX, cost of line outages, cost of line losses, and constraint costs) were pursued by the GB SO, to evaluate a range of potential GB transmission network solutions for the accommodation of the Gone Green scenario (developed by National Grid in 2008), and other scenario variants, in 2020 [1.26]. However other drivers for reinforcement exist and have been used in other studies to optimise network reinforcement. For example:

- Reliability drivers through the minimisation of loss of load expectation [1.27], loss of load cost [1.28] and expected energy not supplied [1.29];
- Security concerns through minimising voltage drop [1.30] or maximising the level of deterministic security criterion adhered to (i.e. N-1 or N-2 contingency) [1.31];
- Drivers related to providing or maintaining a non-discriminatory, competitive deregulated electricity market through minimising market risk [1.32], load curtailment costs [1.33] and variations in nodal pricing [1.27], or maximising social welfare for all market participants (companies related to generation, transmission and distribution) [1.34]; and
- Line congestion concerns through the maximisation of available power transfer capability [1.35] or the minimisation of transmission line loading [1.36].

The transmission network must be kept within operational and design limits at all times to avoid damage to network assets and ensure a reliable supply to meet electrical demand. The application of a new reinforcement with new line parameters to the network affects the system power flow and can cause network issues in other areas by increasing the required power transfer capacity of another line above the associated thermal and/or voltage drop line limit. Hence each reinforcement needs to be designed to alleviate local network issues whilst minimising negative impacts on the wider system, and an optimal reinforcement plan needs to be generated to guarantee the best use of resources. A sub-optimal reinforcement plan will result in additional and unnecessary reinforcements at a higher cost to the consumer that could further exacerbate network issues.

Many national energy scenarios have been created and are a realistic possibility for the evolution of the current UK electricity system to a system which can meet legally binding carbon budgets and achieve future emission reduction targets. By planning the transmission network for a scenario, valuable information can be provided to the SO and TNOs as to potential future areas of network strain. Further, TNOs can identify from the analysis which locations, options and capacities of reinforcement are beneficial (or detrimental) to their system. Another perspective is that transmission network planning can identify the targets that can be reached by the SO and TNOs, for the objectives chosen, with an optimal use of reinforcement resources.

On top of providing information and perspective to the TNOs and SOs regarding future operations, scenario related transmission planning can guide government energy policy in determining the best route forward to economically meet emission targets. This can be done by comparing the associated benefits and incurred costs of the plans generated for different energy scenarios. Thus, scenario related transmission planning can either justify the governmental incentives currently provided (i.e. through CfD), or encourage a new incentive program, designed to drive generation connections towards a more favourable generation mix.

Transmission network planning has always been an important issue in HV power systems. Recently however, due to (amongst other system evolutions) the deregulation of the electricity market [1.37], increased environmental concern [1.8], changes to governmental energy policy [1.8] and the associated rise in the penetration of renewable generation [1.11], many research studies have been carried out in transmission network planning [1.27]-[1.36]. These studies have involved different views, methods, constraints, and objectives (as previously discussed) to the planning problem. Further, due to the improvement in computer power availability and the efficiency of optimisation algorithms, more complicated and expansive problems are now able to be solved.

### 1.1.4. Approaches in Transmission Network Planning

Various models and approaches for transmission network planning, specifically transmission expansion planning (TEP) – which can involve the expansion of the network to new identified nodes for generation connection – exist and many TEP models were reviewed initially in 2003 [1.37] and then in 2013 [1.38]. The review in 2003 highlighted the increasing effect during the previous ten years, on the number of studies carried out in transmission planning due to the deregulation of the electricity market in the UK power system and many other power systems. However, several drawbacks were highlighted from the modelling pool. These included (amongst others):

- The lack of models focused on dynamic planning (where the timing of transmission line installations is also established) and the focus instead on static planning where optimal line additions are set for a single year;
- The lack of alternative options such as redesigning, rearranging or line upgrading (as well other reinforcement options) on top of line addition in the planning algorithms used;
- The exclusion of FACTS devices as part of the planning solution;
- The lack of a coordinated TEP-GEP (generation expansion planning) model to consider the combined nature in real power systems of the generation and transmission sectors; and
- The exclusion of considering multiple contingencies (i.e. the failure of more than one system component) in the security criterion.

Many of these drawbacks, as highlighted in the updated 2013 review, have now been dealt with and explored in TEP models. Furthermore, multiple contingencies have also now been included as an objective to the TEP problem [1.31]. However, the lack of alternative options for reinforcement or expansion of the network and the lack of an ability to redesign and rearrange the reinforcements within the planning algorithm is still a present drawback.

The models employed in transmission planning can be classified into two types: mathematical optimisation and heuristic. Latorre *et al.* [1.37] described mathematical optimisation models as models able to "find an optimal expansion plan by using a calculation procedure that solves a mathematical formulation of the problem". Whereas heuristic models were described as models that "instead of using a classical optimisation approach, go step-by-step generating, evaluating, and selecting expansion options, with or without the user's help (interactive or non-interactive)". Heuristic models perform local searches with the guidance of logical or empirical rules and/or sensitivities. These rules are used to generate and classify the solutions during the search. The heuristic process is carried out until the algorithm is no longer able to find a better solution considering the pre-defined assessment criteria (or objective evaluations).

Many methods that can be defined as a mathematical optimisation model or a heuristic model have been proposed and employed to solve the transmission planning problem. Mathematical optimisation methods such as linear programming [1.39], nonlinear programming [1.40] and mixed integer programming [1.41], as well as heuristic optimisation methods such as differential evolution [1.42], simulated annealing [1.43] and tabu search [1.44] have all been used. The method employed by the GB SO (to analyse the 2008 Gone Green scenario, as well as other scenario variants, for the year 2020 [1.26]) did not involve optimisation but used a linear mathematical relationship to carry out a cost benefit analysis on a set of pre-defined reinforcements. This cost benefit analysis (CBA) economically justified a transmission reinforcement using the following formulation:

$$C_{TR} + C_{OUT} < C_{CON} + C_{TL} \tag{1-1}$$

where $C_{TR}$ is the transmission reinforcement capital cost; $C_{OUT}$ is the cost of outages needed to accommodate the reinforcement construction; $C_{CON}$ is the constraint costs saved over 15 years from alleviating network congestion, and $C_{TL}$ is the transmission losses costs saved over 15 years.

Reinforcements (from the set) that achieved a high cost benefit according to the CBA were identified as a requirement to strengthen the GB transmission system for the scenarios under study. As with many mathematical or heuristic methods employed, the method used by the GB SO embraced the multi-objective nature of the transmission network planning problem where a planned reinforcement can have many potential benefits and drawbacks to the system. However, in using the above relationship the complexity of the problem was not fully explored and the associated trade-offs were not assessed in the study. This complexity arises, in part, from the conflicting nature of the objectives considered and a multi-objective analysis can be used to include these aspects.

Classical multi-objective optimisation – similar to the form of the relationship in (1-1) – involved the conversion of the multi-objective problem to a single-objective optimisation. An example of this – and probably the most widely used classical approach – is the weighted sum method, which combines a set of objectives into a single objective by pre-multiplying each objective with a user-defined weight [1.45]; as formulated below:

$$F(x) = \sum_{n=1}^{N} w_n f_n(x) \tag{1-2}$$

where $F(x)$ is the weighted sum of the objectives (to be maximised or minimised for the optimisation) and $f_n(x)$ and $w_n$ are the objective and associated weight, respectively, for the n$^{th}$ criteria.

However, these classical approaches can over-simplify the objective trade-offs. In multi-objective optimisation, a set of optimal solutions that include the objective trade-offs will be found by considering all objectives to be of equal importance [1.45]. Then a decision can be made on the best solution from this set. There have been many methods of multi-objective optimisation proposed since, which keep the objectives apart and seek Pareto-optimal solutions – a solution is Pareto optimal if it cannot improve in one objective without detriment to the other objectives [1.45]. The benefit of this approach to transmission planning is twofold. Firstly, by investigating objective trade-offs the network planner is aided in defining the positive and negative effects that can result from investing more or less into the transmission network, encouraging or discouraging further network investment. Secondly, expansion plans generated from multi-criteria analysis, due to the unweighted nature of the objectives, give the network planner a number of reinforcement possibilities for different planning goals, which may not have been considered.

Meta-heuristics are high level problem-independent techniques which can be used as a black box and therefore moulded to a wide range of problems to develop the heuristic optimisation algorithm [1.46]. Recently, different researchers have proposed a new group of meta-heuristic multi-objective optimisation techniques which utilise the concept of evolution. These techniques are generally referred to as Multi-Objective Evolutionary Algorithms (MOEAs). MOEAs offer the flexibility to solve multi-objective problems without the need to aggregate the objectives into a single measure of performance [1.45]. MOEAs are powerful techniques which can handle groups of possible solutions simultaneously; find several Pareto-optimal solutions in a single "run"; and optimise discrete objective functions that are non-convex and nonlinear [1.47].

As such, in the last 15 years the design and utilisation of MOEAs has been a very active research area. One of the most advanced and recognised MOEAs at present remains the

Strength Pareto Evolutionary Algorithm 2 (SPEA2), developed in 2001 by Ziztler *et al.* [1.48]. The algorithm has been demonstrated to outperform other MOEAs and meta-heuristics in both theoretical and practical problems [1.48]-[1.50], and therefore is well verified for dealing with multi-objective problems. For this reason, the SPEA2 has been chosen for use in the optimisation stage of the framework proposed in this thesis.

Chapter 2 presents a review of the meta-heuristic techniques and associated frameworks which have been applied to the multi-objective transmission planning problem in a deregulated system. The concepts and development of MOEAs has recently been discussed extensively by Alarcón-Rodríguez [1.47]. The review in Chapter 2 therefore has a focus on the problem specific design of the frameworks. The SPEA2 algorithm, despite its successful application to many power system problems from distribution network configuration planning (i.e. the operation, location and number of sectionalizing switches and tie lines within the network[2]) [1.51] – [1.52], to distribution energy resource planning [1.47], at the time of the work carried out in this thesis, had yet to be applied to the transmission planning problem, or indeed, as with many other MOEAs, to a large-scale multi-voltage network such as the GB system. Recently, the SPEA2 has been used in a long-term simplified TEP study [1.53]. However, the algorithm was applied to a series of standardised and simplified network models as specified by Romero *et al*. [1.54] to test its performance. Hence one of the contributions of this thesis is to facilitate the understanding of meta-heuristic techniques and their use in transmission network planning.

### 1.1.5. Scenario Evaluation

As a result of increasing worldwide environmental concern, the UK government, under the Climate Change Act (2008), has set a target of at least an 80% reduction in the net UK carbon account, from baseline 1990 levels, by 2050 [1.8]. Legally binding carbon budgets which restrict the total amount of greenhouse gases that can be emitted over a 5-year period have been set to achieve these emission targets. The first three carbon budgets were set in May 2009 and require emissions to be reduced by at least 34% below base year levels in 2020 [1.55]. The fourth carbon budget, covering the period 2023–27, was set in June 2011 and requires emissions to be reduced by 50% below 1990 levels [1.55].

[2] The use of sectionalizing switches and tie-lines improve the reliability of an electrical network. Sectionalizing switches are placed in a network to isolate faulty sections. Tie-lines provide alternative supply paths to various sections following a fault.

This overall reduction in greenhouse gas emissions needs to be achieved across all sectors of the UK economy. In 2009, 37% of UK emissions were produced from heating and powering homes and buildings; around a quarter of UK emissions were produced from domestic transport; just under a quarter of UK emissions were produced from the industrial sector (i.e. mainly through generating the heat that is needed for the industrial process) and around 9% of UK emissions resulted from agriculture, land use, forestry and waste [1.55]. The carbon plan states that some sectors need to decarbonise more than others, with the power sector (which accounted for 27% of UK emissions by source in 2009 [1.55]) needing to fully cut emissions by 2050 [1.55]. This represents a significant cross-sector challenge, where a multitude of options exist and many plans for delivery can be generated.

Considering this challenge there has been a rise, recently, in the number of UK low-carbon policy related studies, some of which adhere to the existing carbon budgets and achieve the emission targets for 2020 and/or 2050. The most prominent research projects are LENS 2050 [1.56], SuperGen Networks 2050 [1.57], DECC 2050 [1.58], UKERC's Energy 2050 project [1.59] and the *Transition Pathways to a Low Carbon Economy* consortium[3]. From these studies, a growing number of national energy scenarios have been created which have a strong focus on fully decarbonising the UK's electricity system. An example of this is in the DECC 2050 project where several scenarios or 'pathways' have been created, using an online interactive framework (available at [1.60]), and each pathway is set a different challenge to achieve the 2050 emissions target [1.58]. The resulting pathways consider a range of possible effects on the UK system such as the deficiency of CCS technology, or new nuclear plant.

However, when evaluating these scenarios, the research projects mentioned above either made significant simplifications in assessing the electrical transmission network reinforcement requirements, and associated costs, of a scenario or did not consider them at all [1.56]-[1.57]. For DECC 2050, an overall reinforcement cost was simply attributed, without application of a power flow, using a £million/GW coefficient on the overall network carrying capacity. Hence there was no geographical consideration of the reinforcement requirement. For UKERC's Energy 2050 project, electrical infrastructure requirements were greatly simplified and detailed transmission costs were only evaluated for the gas network using a combined gas and electricity networks model [1.61].

[3]http://www.realisingtransitionpathways.org.uk/

The exception to the above studies, in assessing the reinforcement requirement of the transmission network for a scenario, is the study carried out by the GB SO for the Gone Green scenario (developed by National Grid), as well as other scenario variants, for the year 2020 [1.26]. As previously stated, the method involved evaluating a range of pre-defined transmission network solutions, using a linear mathematical relationship (1-1), for the UK transmission network to accommodate the scenarios. However, the focus of this analysis was network based and the conclusions drawn were based on the success against a CBA, of the reinforcements suggested by the TNOs prior to the application of the scenario. The reinforcements proposed were not necessarily designed to meet the required network capability of the Gone Green scenario. Reinforcements developed by the TNO can often be designed to cater for a contracted generation background or an alternative future energy scenario, such as Slow Progression (also developed by National Grid) – the Gone Green scenario is generally regarded as an ambitious scenario. Hence the purpose of the study was to evaluate the reinforcements and not the scenario.

In evaluating a scenario and its economic impact on the electrical transmission system, a wide range of possible transmission reinforcements need to be generated for the specified scenario and subsequently assessed to obtain the best reinforcement solutions and derive the network reinforcement cost. This approach differs from the modelling work of the GB SO and TNOs, and some transmission planning models, which utilise a set of candidate reinforcement (or expansion) solutions as an input that are irrespective of the associated scenario in the study.

Chapter 3 presents a review and discussion of influential UK low-carbon studies and the associated future energy scenarios. A large number and variation of energy scenarios have been created for the UK energy system, highlighting the need for a flexible framework to be created which can analyse these scenarios and provide an indication of the economic impact of each scenario to the transmission network.

### 1.1.6. Outline of the proposed Modelling Approach

This thesis proposes a flexible, systematic, multi-objective transmission reinforcement planning approach to enable the evaluation of future energy scenarios to the GB network. The approach adopted generates transmission reinforcement plans (TRPs) to alleviate the resulting thermal constraints from the application of a scenarios generation mix to the base case network. Each TRP is evaluated against the objectives of minimising capital investment cost; outage costs (needed to accommodate the reinforcement construction) and annual incremental operation and maintenance (O&M) costs (associated with the extra O&M requirement for an added line), whilst maximising the savings in annual network constraint costs and annual line losses.

The TRPs generated are assessed against a stochastic, seasonal evaluation of annual network congestion, which reflects the uncertainty of annual generation output and the impact of planned network outages on annual system constraints. The objectives chosen are broadly in line with the drivers defined in the CBA for the Gone Green study by the GB SO [1.26]. However, the approach adopted in this thesis utilises the SPEA2 algorithm to account for nonlinearities of the multi-objective problem and enables the exploration of trade-offs associated with the conflicting nature of the chosen objectives.

To generate a TRP, the options considered are to upgrade the existing line (single-circuit or double-circuit) at the same voltage level through reconductoring, and line addition (single-circuit and/or double-circuit) at the same voltage level. This adds alternative options for network reinforcement in comparison to the singular, single-circuit, line addition option incorporated into the design of previous TEP models (for example, [1.62] – [1.64]). The inclusion of line reconductoring, a cheaper alternative to line addition, is therefore an important step in the continued evolution of the models employed for multi-objective transmission planning.

The primary purpose of the modelling approach of this thesis is to evaluate a future energy scenario and so TRPs are located for a single scenario as opposed to being located for multiple scenarios (as studied by Maghouli *et al.* [1.64]), where the focus of the modelling work lies with defining the most suitable network reinforcements or expansions under an uncertain generation expansion plan. This can be an advantage as this allows for exploration of an expanded search space of reinforcement options in comparison to previous transmission planning multi-objective models. The modelling framework proposed as part of this thesis enables the exploration of varying locations, configurations and capacity limits of transmission reinforcement.

The proposed framework utilises a systematic planning algorithm to generate individual reinforcements, and overall reinforcement plans, as well as to alter the capacity and configuration of the associated reinforcements, and potentially add reinforcements to the existing plan, should the original solutions exacerbate thermal constraints. As previously stated, the inability to redesign or rearrange reinforcements in TEP models was originally identified as a drawback by Latorre *et al.* [1.37], and this continues to be the case in multi-objective transmission planning. This process is important to ensure that the original TRP is given the opportunity to exceed beyond the construction phase, and only minimal necessary alterations to the TRP are made by the algorithm, to maintain, as far as possible, the initial characteristics of the plan.

These associated design innovations to the modelling framework detailed as part of this thesis enable the creation of a wider range of reinforcement solutions, enhancing the multi-objective assessment and increasing the likelihood that a number of optimal TRPs for the multi-objective problem will be located (via the SPEA2) that can better or match the economic performance of candidate solutions designed by the GB TNO and selected by the GB SO. Also, the evolutionary nature of the framework solution may yield feasible TRPs not considered by the network planner. Fundamentally, these innovations increase the likelihood that the modelling approach of this thesis will be able to realistically evaluate the economic impact, to a transmission network, of the scenario under study.

The modelling approach has been designed and developed to ensure that each TRP generated adheres to thermal constraint criteria defined by the NETS SQSS [1.65] – a document which sets out a coordinated set of criteria and methodologies that transmission licensees shall use in the planning and operation of the GB electrical transmission network. As these rules are specific to the GB transmission network and part of current planning practice, the approach can only be realistically applied to the GB network. However, the bulk of the methods used in the modelling framework are generic and can be applied to other multi-voltage transmission network planning problems.

The capability of the modelling approach is demonstrated in this thesis against three published case studies; a scenario for the year 2020, known as Gone Green (developed by National Grid), and two scenarios generated for the year 2035, known as Market Rules and Central Co-ordination (developed by the 'Transition Pathways' consortium). The Gone Green 2020 case study is used to compare cost savings of the optimal TRPs generated by the proposed modelling approach against the savings from the solutions created by the GB TNOs [1.26]. This is to test the suitability of the solutions generated by the modelling approach and therefore the framework itself as a means for scenario evaluation. The Market Rules and Central Co-ordination 2035 case studies are used to give further examples of how the modelling framework can be utilised, and the benefit of the approach for scenario assessment.

Market Rules requires significantly more generation from fuel sources such as gas, coal and wind (offshore) compared to Central Co-ordination. Hence, these case studies are used to show the value of the proposed framework for providing feedback on the likelihood, from a network perspective, of the scenario being adopted. Also, the value of the framework in potentially aiding governmental energy policy and informing the incentives currently provided (through CfD) to encourage the connection of renewable generation. Questions related to generation expansion, posed by comparing two scenarios, can effectively be answered with help from the framework. As an example, and as discussed later in this thesis, the framework can quantifiably answer from the perspective of the network – using an extensive dataset for generation connection dates and transmission entry capacity – the questions below regarding Market Rules and Central Co-ordination in 2035:

- Is it beneficial for the UK system to have a higher penetration (in particular as a function of total supply) of coal/gas (with CCS) plant and generation from offshore wind, and a lower penetration of nuclear, to meet electrical demand?
- What is the economic impact of the various demand reduction measures employed in Central Co-ordination?

The application of the framework developed as part of this thesis to Market Rules and Central Co-ordination for 2035 provides an example of how a preferred scenario, from the perspective of the transmission network, can be determined for the same year from the generated multi-objective results. This involves making a verdict from the frameworks outputted set of optimal TRPs. An example of how this verdict can be reached is detailed in Chapter 5; however, several methods can be used to assess the scenario from the frameworks results. The method chosen to carry out a verdict therefore reflects the point of view of the user. As it is not the intention of this work to develop a modelling approach to find the single least-cost transmission reinforcement plan from a particular point of view, a method for obtaining a verdict on the scenario is excluded from the framework.

## 1.2. *Thesis Objectives and Methodology*

This research establishes that an MOEA-based multi-objective transmission reinforcement planning framework can provide valuable information to aid in defining the ideal future energy scenario for the UK to achieve environmental targets. Accordingly, the main objective of this thesis is to design, develop and test a systematic modelling approach for the creation of economically comparable reinforcement plans (for the multi-objective transmission planning problem) to GB TNO solutions, that adhere (where possible) to current GB planning practice, for the analysis of a multitude of future energy scenarios.

The modelling framework has been designed to answer the following questions:

- What future energy scenario, from those considered, is most likely to require minimal transmission network reinforcement and investment?
- And therefore, what penetrations and types of renewable and conventional generation are preferred, from a network perspective, to economically meet electrical demand? And what is the associated potential economic impact of reducing electrical demand?
- What sizes, locations and configurations of reinforcement result in optimal scenario related transmission reinforcement plans to achieve multiple, crucial, planning objectives?
- What are the scenario-related correlations and trade-offs between these planning objectives when the network has been reinforced optimally?

The following methodological steps are required to achieve the main objective of this thesis, and evidence of this approach is provided throughout this work:

- Develop appropriate knowledge of multi-objective optimisation, meta-heuristic techniques and the algorithms employed to select a suitable algorithm for use in the framework.
- Perform a critical review of the current methods and models used for scenario assessment.

- Examine the complexity of the transmission network planning problem, understand the current methodology of the GB TNOs and SO for transmission planning in a deregulated power system, and determine the current, crucial drivers for optimal reinforcement of the GB network.
- Perform a critical review of the state-of-the-art meta-heuristic techniques used for multi-objective transmission expansion and reinforcement planning in a deregulated system.
- Develop a modelling framework that is flexible enough to systematically create a wide range of reinforcement options and assess many future energy scenarios.
- Demonstrate the value of the modelling framework by applying it to several relevant scenario case studies.

## 1.3. *Associated Publications*

This thesis presents a novel multi-objective transmission reinforcement planning approach to analyse the thermal and economic impact of a future scenario to the GB network. The framework utilised includes the current main drivers for transmission reinforcement and integrates a well-known and advanced MOEA into a flexible analysis platform. The main contributions of this thesis are discussed in Chapter 6. The work associated with this thesis has directly lead to the following publications:

The proposed framework is described and tested against a scenario generation mix for 2020 (based on the Gone Green scenario developed in 2011 by National Grid) in:

- Barnacle, M., Galloway, S., Elders, I., Ault, G., "*Multi-objective transmission reinforcement planning approach for analysing future energy scenarios in the Great Britain network*", IET Generation, Transmission and Distribution, vol. 9, no. 14, pp. 2060-2068, November 2015

An initial design iteration of the framework was used to assess three scenarios, generated via a two-region UK Market Allocation (MARKAL) model, for 2020 in:

- Barnacle, M., Ault, G., "*Network reinforcement requirements for Scotland and the rest of the UK (RUK) – and possible solutions for this*", In Fraser of Allander Institute Quarterly Economic Commentary – Special Issue on Economic and Energy System Modelling, vol. 3, pp. 9-12, April 2012

An earlier version of the modelling approach – which excluded optimisation via the SPEA2 and directly outputted initial reinforcement solutions – was used to assess, in combination with the Future Energy Scenario Assessment (FESA) tool, the robustness and rationale of the Market Rules scenario (developed by the *Transition Pathways to a Low Carbon Economy* consortium) in:

- Barnacle, M., Robertson, E., Galloway, S., Barton, J., Ault, G., "*Modelling generation and infrastructure requirements for transition pathways"*, Transition Pathways to a Low Carbon Economy Special Issue, Journal of Energy Policy, vol. 52, pp. 60-75, January 2013

Additionally, the author has carried out a simulation to evaluate the impact of the Market Rules scenario on electrical $CO_2$ emissions, which was used to define the success of the scenario at achieving UK governmental targets by the 'Transition Pathways' consortium. This is presented in:

- Barnacle, M., Alarcon-Rodriguez, A.D., Ault, G., Galloway, S., "*Emissions-based Simulation to Evaluate Long-term Low Carbon Transition Pathways for the UK Gas and Electricity Infrastructure*", 44$^{th}$ international Universities Power Engineering Conference, UPEC 2009, Glasgow, UK, September 2009

## 1.4. *Thesis Structure*

The structure of this thesis reflects the methodological steps and contributions of this work. This thesis is divided into six chapters. A detailed description of each chapter is provided next to facilitate the understanding and use of this thesis.

**Chapter 1** is the introduction of the thesis. It introduces the current state of the GB electrical transmission network and discusses the need for network reinforcement. The background and motivation of this thesis is then discussed and the research objectives and methodological steps followed are then detailed.

**Chapter 2** provides a review on the current GB TNO/SO methodology for transmission planning on the GB system and reviews and discusses the key meta-heuristic approaches used for transmission planning. The chapter has four main sections. The first section discusses in detail the transmission planning problem, highlighting the multi-objective, dynamic and complex nature of the planning problem, particularly in a deregulated electricity market. The second section details the current structure and the methods employed by the GB SO and GB TNOs to satisfy the transmission planning objectives of the regulator under the price control. The third section reviews the meta-heuristic techniques used in transmission planning. The fourth section reviews the meta-heuristic methods and frameworks employed for the multi-objective transmission planning problem in a deregulated environment, and the associated limitations and simplifications of the approaches. The computational complexity and limitations of the techniques used helped to define the objective and scope of the proposed framework.

**Chapter 3** presents a review and discussion of influential UK low-carbon studies and the associated future energy scenarios. The ethos of the various scenario narratives, the scenario targets and aims, the methods used for scenario creation and the models used for scenario evaluation are discussed. Emphasis of the discussion is placed on the models used for scenario evaluation, establishing the need for a model to adequately assess the spatial and temporal economic impact of a future energy scenario to the GB transmission network.

Following on from Chapter 2 and 3, **Chapter 4** comprehensively details the objective, scope and design of the proposed framework. The framework utilises an MOEA and has been designed to thoroughly explore three variations in reinforcement characteristic; location, configuration and line capacity. The framework utilises a systematic planning algorithm to create reinforcement solutions for each plan, as well as to redesign/reconfigure the reinforcement solutions, should a plan be found to exacerbate thermal constraints. The implementation of the MOEA and the methods employed to achieve the above flexibilities and considerations is detailed. Further, the calculation procedure for each one of the objectives chosen to simulate the transmission planning problem is explained.

In **Chapter 5**, the proposed multi-objective transmission reinforcement planning approach is applied to three published case studies. As mentioned previously, the first case study relates to a scenario in the year 2020 and is used to examine the suitability of both the solutions generated by the approach and the framework itself as a means for evaluating a future energy scenario. Results illustrate the robustness of the modelling approach proposed. The next two case studies relate to scenarios with different generation mixes in the year 2035. Results demonstrate that the approach proposed can be used for scenario evaluation, and can be applied to answer the network and energy policy related questions set for the scenarios under study. The discussion from all three case studies provides useful information about the impacts and benefits of various reinforcement solutions and various penetrations of renewable/conventional generation to the GB network.

**Chapter 6** presents the conclusions of this work and the contributions made to current knowledge. This focuses on the usefulness of the modelling approach for both transmission reinforcement planning and for scenario evaluation. Possibilities for future work are included, which outline the improvements that could be made to the framework. These include the use of an AC power flow-based model of the GB network (as opposed to the DC power flow-based model utilised) and the inclusion of further options for network reinforcement and expansion to the framework, such as FACTS devices and offshore subsea HVDC/HVAC cables.

## 1.5. Chapter 1 *Summary*

This chapter presents the background to the thesis and introduces the motivations of this investigation. The objective and methodology followed is outlined. In addition, the work is put into context and the structure and scope of the thesis is detailed.

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# Chapter 2

# 2. Transmission Network Planning and the Techniques Employed

## 2.1. *Introduction*

This chapter presents an overview of the current transmission planning problem, and discusses the multi-objective, dynamic and complex nature of transmission planning, particularly in a deregulated environment. Different approaches to transmission planning are discussed and potential security and reliability constraints associated with the planning problem are detailed. The network models which can be used in transmission planning are then detailed, and the associated limitations divulged. The complexity of transmission planning in a deregulated environment is then discussed before a review is carried out into the current co-ordinated GB TNO/SO approach to transmission planning. This review looks at the method employed by the GB TNO and/or SO for defining reinforcement requirement, creating reinforcements to meet this requirement, and the CBA assessment.

Meta-heuristic techniques which have been applied to the transmission planning problem are then reviewed before a further appraisal is carried out on the latest modelling approaches and frameworks which incorporate a meta-heuristic to solve the multi-objective transmission planning problem in a deregulated environment. Limitations and simplifications of these approaches are highlighted, for which the MOTREP framework proposed in this thesis has been designed to resolve for the purposes of more accurately assessing the economic impact of a future energy scenario to the GB transmission system.

## 2.2. *The Transmission Planning Problem*

Transmission network planning can be defined as a structured approach to optimise the configuration, location and capacity limits of network reinforcements and/or expansions (i.e. to new network nodes) for a transmission system given a set of objectives and constraints. Electrical transmission reinforcement and/or expansion is driven by load growth, supply security, the relative location of demand and generation, and generation costs associated with constraint actions, connection, or use of system charges. As discussed in Chapter 1, with the emergence of renewable generation, the location of generation is continually changing on the GB system and furthermore the costs associated with constraining renewable generation can be significant. Ultimately the aim of transmission planning is to propose a reinforcement and/or expansion plan which will minimise the CAPEX requirement as well as the associated costs to implement the plan (from minimising network outages), and minimise the associated operating costs over the lifetime of the plan. Costs associated with the operation of the network can relate to generation constraint actions, maintenance costs (associated with route patrols, inspections, vegetation management and tower painting) and network losses.

Transmission planning is intrinsically multi-objective with conflicting criteria. A higher investment in transmission assets, will likely result in higher costs associated with network outages (to accommodate the plan construction, connection and energisation) and maintenance, and lower costs associated with constraining generation. As well as reinforcement of the existing system to meet load and generation growth, network expansion is required to connect new generation at new locations. Each network proposal for reinforcement or expansion could face difficulties relating to the geography of the area and in obtaining rights of way on the network. Planning permission from local planning authorities might be required as well as environmental consents and agreement with relevant land owners (where the TNO does not own or occupy the land). These issues often result in transmission network projects becoming problematic and can cause significant delays, increasing the overall cost of the project. Hence, it is important to propose an economic transmission plan which can maintain a reliable and secure supply at minimal cost.

In general, a transmission network plan should aid in answering the following three questions:

- **Where** is reinforcement or expansion required?
- **What** reinforcement or expansion solution should be implemented?
- **When** is the network solution required?

As summarised in Chapter 1, there are a wide range of network reinforcement and expansion solutions. Further, the capacity of the network solution needs to be identified. This creates a large search space for optimisation.

### 2.2.1. Static, Dynamic and Multistage Planning

There are three different approaches to the transmission planning problem which are designed to answer some of the above questions:

1. Static planning [2.1]-[2.2];
2. Dynamic planning [2.3]-[2.4]; and
3. Multistage planning [2.5]-[2.6]

In static planning the optimal transmission network configuration and capacity is calculated for a single specified future year [2.7]. Planners are not concerned if a transmission solution proposed for the horizon year is required to be energised and commissioned beforehand. Costs associated with the planning problem are therefore determined for the horizon year. In dynamic planning, the lead time of network solutions is considered and therefore an interval of several years before the horizon year can be included in the optimisation [2.3]. Although dynamic planning can often provide the same optimal network configuration by the end of the planning horizon as with static planning (as found in [2.4]), dynamic planning aids the decision on when to add new assets to the system, and enables the system configuration to be updated over the planning period for dynamic changes in demand and network assets (as a result of decommissioning) [2.4]. This approach can therefore improve the evaluation of a plan and therefore reduce the costs of the considered objectives. From the point of view of the TNO, transmission planning is a dynamic problem. Major network reinforcements proposed (such as Beauly-Denny in the GB system, see Chapter 1) can have a significant lead time and incremental reinforcements may be needed in the meantime, such as line re-profiling or reactive compensation, to secure the system.

In multistage planning, the planning horizon is split into several stages, treating each stage as a separate static planning problem. This enables the optimal plan from a previous stage to be used as the base case for the following stage; this is known as the "forward" method [2.7]. Alternatively, a "backward" approach can be adopted [2.7], where the proposed transmission solutions for the final year are candidates for planning in the previous stage. This process continues back to the base case system. Multistage planning is particularly useful when considering incremental reinforcement works such as reactive compensation or the implementation of Quadrature Boosters or Phase Shifting transformers. When utilising the forward method, these cheaper solutions can be implemented in one stage before being renewed, replaced or excluded at a later stage as a result of implementing wider, more significant reinforcement works. Rahmani *et al*. [2.5] utilised a linear multi-stage transmission expansion planning model to better simulate the economic benefits of the inclusion of fixed series compensation as well as candidate line additions in the planning horizon. However, multistage planning often results in overinvestment in the transmission network as the optimum solution for each stage may not equate to the global optimal solution across the planning timeline under dynamic planning, where all stages are effectively simultaneously integrated into the optimisation.

Static planning generally answers **Where** and **What** in regards to transmission reinforcement or expansion, whereas dynamic and multistage planning can answer **Where**, **What**, and **When**. However, the complexity of the problem differs for each approach. In dynamic planning the simultaneous optimisation of network reinforcement or expansion solutions for all years in the planning horizon increases the size and complexity of the problem and the decision variables involved. Multistage planning is a simpler problem however the approach requires optimum network solutions to be determined for each stage in the planning timeline as opposed to one stage under static planning. Simplifications elsewhere in the model are likely to be required when implementing a dynamic or multistage approach to limit computational effort. These simplifications often occur in the objective evaluations of the transmission problem, or in the base network on which the approach is applied. For example, Romero *et al.* [2.8] proposed a multistage planning method to incorporate the complexity of the dynamic planning problem, however the approach was applied to a series of transportation network models which relax many system constraints in comparison to the DC network model, and the AC network model.

Ultimately, dynamic planning (and to a certain extent multi-stage planning) should be considered for the problem proposed if the extra computational requirement and the simplifications made elsewhere in the approach, are outweighed by the benefits of knowing **When** network investment should be made.

### 2.2.1. System Constraints and Security of Supply

The transmission network must be kept within operational and design limits at all times to avoid damage to network assets and ensure a reliable supply to meet electrical demand. As described in Chapter 1, these limits relate to the power transfer capacity of a transmission line (or other network asset) which may be restricted by thermal, voltage or stability criteria. For the GB electrical transmission network, transmission licensees are required to adhere to a coordinated set of operational and planning criteria outlined in the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) [2.9]. This criterion is outlined for both the onshore transmission system and offshore transmission system for the benefit of the GB TNOs and OFTOs. Criteria are outlined for generation and demand connections (both onshore and offshore), the design of the main interconnected transmission system (comprising of the 400kV and 275kV system and, where operated in parallel with the 400kV/275kV system, the 132kV system in Scotland), operation of the transmission system (both onshore and offshore), and system wide planning and operational voltage limits (both onshore and offshore) [2.9].

Generally, for an intact system and an appropriate generation background (including reasonable assumptions on output and availability), transmission equipment loadings must not exceed pre-fault ratings and voltages cannot exist outside the pre-fault planning voltage limits for the transmission system at peak demand or for demand at any point during the course of a year of operation. For thermal constraint criteria, a pre-fault rating of around 84% of the post-fault continuous rating is believed to be suitable to restrict the risk of exceeding equipment temperature [2.10]. For voltage, different conditions are outlined for the intact system depending on the nominal voltage level and timescale (i.e. planning or operational). In general, the steady state voltage level pre-fault should not fall below 95% of the nominal voltage level and shall not exceed 105% (102.5% at 400kV), under planning or operational timescales.

To meet electrical demand efficiently and economically, supply security is paramount. In the UK, the electricity and gas market regulator Ofgem until recently has produced and published a capacity assessment report on projections for the next three winters against projected peak demand [2.11]. The report considers the margin of generation against demand, and informs the UK government and Ofgem decisions on electrical supply security. For security of supply in the UK the government, Ofgem and National Grid, as GB SO, all have key roles and responsibilities [2.11]:

- **Government**: sets the target level of generation capacity to meet demand for the near future and introduces policies to enable the market to deliver this objective.

- **Ofgem**: ensures that market arrangements are sufficiently designed and approves as well as regulates (indirectly through cost recovery mechanisms) the introduction of balancing services to economically achieve supply security for network consumers, and ensure quality of service in the overall operation of the GB system.
- **National Grid**: as GB SO, has an obligation to balance generation and demand on the system (on a second-by-second basis) in an economic, efficient and co-ordinated manner. The SO can buy and sell energy and procure associated balancing services. Further, the SO can propose new balancing service mechanisms to help balance the system should the near-term margin tighten.

Further to ensuring that the margin between generation and demand in the near term is sufficient, TNOs (to avoid significant cost penalties) need to ensure that the transmission system at peak demand is designed to be supply secure against planned outages, to accommodate reinforcement or maintenance works, and fault outages as a result of weather conditions or faulty electrical equipment. The NETS SQSS states that following the fault outage of any of the following:

- A transmission circuit, or source of reactive power (an N-1 contingency);
- A double-circuit OHL (excluding double-circuit overhead lines solely within SPT's transmission system – an N-D contingency); or
- A single transmission circuit with the prior outage of another transmission circuit, or generating unit, or source of reactive power in NGET's transmission system (an N'-1, N-1-1 or N-2 contingency – this includes the prevailing condition of the system).

there shall not be a significant loss of supply capacity, unacceptable overloading (i.e. above the post-fault continuous rating) of primary transmission equipment or unacceptable voltage conditions on the Main Interconnected Transmission System (MITS). Further, system instability shall not occur following a fault outage; the sudden unexpected outage of a transmission circuit or generating unit can result in a loss of generator synchronisation. Post-fault, in general the steady state voltage level should not fall below 90%, and shall not exceed 105% in planning timescales (102.5% at 400kV) and 110% in operational timescales (105% at 400kV). Further to this, in general any post-fault step changes (fall or rise) in voltage on the system should be kept within 6%. An added condition in the NETS SQSS is that steady state post-fault voltages are to be kept within limits without widespread transformer re-tapping or post-fault adjustment of reactive power injection from Static Var Compensators.

While an “N-1”, “N-D” and “N’-1” security criterion is sufficient for the GB transmission system, a higher level of security may be preferred for other networks under more strenuous conditions and under a different market. Choi *et al.* [2.12] proposed a transmission planning model to analyse extensions of the “N-1” contingency criterion and provide the best transmission expansion plans for a small network case study, against the objectives of minimising investment cost as well as generation operating costs and standby costs. However, this security criterion is deterministic in nature and therefore examines fault outages without considering the probability of the fault occurring. The probabilistic approach allows for a more flexible criterion based on reliability indices calculated from the duration and frequency of failure [2.13], and can be used (as demonstrated by Moreno *et al.* in [2.14]) in transmission planning to identify relevant outages for security testing that exclude those that do not contribute to finding an optimum operating solution.

Not all fault outages are severe and frequent. Hence, a probabilistic approach can be used to reduce the number of contingencies tested against, improving the computational performance of the planning approach and potentially reducing the level of network capacity required for a secure system. This in turn may result in lower-cost network reinforcements. However, the application of a probabilistic security criterion adds complexity to the problem, making the analysis less transparent and harder to replicate in comparison to the deterministic method. Further the probabilistic approach relies on an accurate, dynamic, database of failure rates for specific transmission outages. This database would be difficult to develop and maintain in practice [2.15].

As transmission planning timescales are not critical, some planning studies [2.16]-[2.17] propose developing a performance index for assessing the impact of a fault outage on the network prior to solving the planning problem. Performance indices are calculated to assess the impact of every applicable fault outage of every system component against thermal and voltage violations on the system. Contingencies which have an impact on thermal and voltage violations are included in the subsequent transmission planning process, thereby reducing the contingency set. To improve the computational efficiency in the calculation of the performance index, the network model used initially can be simplified (for example a DC model), and a more complicated network model can be used at a later stage to analyse a reduced contingency set from the previous stage (as studied by Agreira *et al.* [2.18]).

### 2.2.2. Transmission Network Model

Depending on the problem proposed and the approach chosen for transmission planning, the accuracy at which the system is modelled and therefore the system constraints able to be adequately considered for the problem is of paramount importance. Different levels of simplification in the mathematical relationships among network variables such as voltage, voltage angle, active and reactive power exist while respecting the physical laws of power flow. For transmission planning studies, the power system can be represented using one of the following three models:

1. Alternating Current power flow (**ACPF**) model [2.19]-[2.20]
2. Direct Current power flow (**DCPF**) model [2.21]-[2.22]
3. **Transportation model** [2.23]-[2.24]

In a full **ACPF** model there is little simplification in representing the transmission system. Active and reactive power injections are simulated as well as the voltage magnitude and voltage angle of each bus or network node in the system. The active power ($P_k$) and reactive power ($Q_k$) flowing in a transmission line *k* between bus *i* and *j* are given by (2-1) and (2-2) respectively [2.25].

$$P_k = V_i V_j \left( G_{ij} cos(\theta_i - \theta_j) + B_{ij} sin(\theta_i - \theta_j) \right) - G_{ij} V_i^2 \tag{2-1}$$

$$Q_k = V_i V_j \left( G_{ij} sin(\theta_i - \theta_j) - B_{ij} cos(\theta_i - \theta_j) \right) + B_{ij} V_i^2 \tag{2-2}$$

where $V_i/V_j$ and $\theta_i/\theta_j$ are the voltage magnitude and voltage angle at bus *i* and *j,* respectively, and $G_{ij}/B_{ij}$ are the real and imaginary part of the $i$th/$j$th element of the nodal admittance matrix. If $r_{ij}$ is the resistance and $x_{ij}$ is the reactance of the transmission line connecting bus *i* and *j*, then $G_{ij}$ and $B_{ij}$ can be represented as follows:

$$G_{ij} + B_{ij} = \frac{r_{ij}}{r_{ij}^2 + x_{ij}^2} - j\frac{x_{ij}}{r_{ij}^2 + x_{ij}^2} \tag{2-3}$$

The full **ACPF** as a result of equations (2-1) and (2-2) includes non-linear constraints with many interdependent variables. Further to this is the nonlinearity of the power system variables themselves. Network losses as a result of active power flows are not known in advance due to the dependence on the pattern of active power injection and the profile of voltage. In **ACPF**, the network loss of a transmission line *k* between bus *i* and *j* can be calculated using the below nonlinear formulation [2.25]:

$$Ploss_k = G_{ij}\left(V_i^2 + V_j^2 - 2V_iV_j cos(\theta_i - \theta_j)\right) \tag{2-4}$$

To reduce the complexity of the **ACPF** and enable large scale optimisation problems of potentially a dynamic or multi-stage nature to be carried out, the **ACPF** can be made linear and the solution iterated, with network losses being assessed at each iteration.

The **DCPF** is a simplified linearised version of the full **ACPF** and looks only at active power flows; neglecting issues related to voltage magnitude, reactive power management and transmission losses [2.26]. The iterative nature of a simplified **ACPF** (particularly for large systems) requires a greater simulation time than a **DCPF** to model the fundamental relationships of parameters in the power system; specifically, active power flows in a network. The three main assumptions of a **DCPF** are as follows:

1. Voltage magnitudes at all buses (or network nodes) are equal to 1p.u.
2. Reactance is much greater than resistance ($r_{ij} \ll x_{ij}$)
3. The difference in voltage angles between bus $i$ and $j$ of a transmission line is quite small; $cos(\theta_i - \theta_j) = 1$, $sin(\theta_i - \theta_j) = (\theta_i - \theta_j)$

The reactive power ($Q_k$) flowing in a transmission line is assumed to be zero and the nonlinear constraint (2-1), as a result of the assumptions above, is transformed into the linear constraint below:

$$P_k = \frac{1}{x_{ij}}(\theta_i - \theta_j) \tag{2-5}$$

This formulation relates to Kirchhoff's voltage law. A further constraint in **DCPF** relates to Kirchhoff's current law, and involves the power balance at each bus or network node. This constraint can be formulated as follows:

$$\sum_{\forall l \in N_{Gm}} G_l + \sum_{\forall k \in N_{Tm}} P_k - L_m = 0 \qquad (2\text{-}6)$$

where $N_{Gm}$ and $N_{Tm}$ are a set of generating units and transmission circuits connected to bus $m$ respectively; $G_l$ is the active power generated by unit $l$ (MW) and $L_m$ is the active load at bus $m$ (MW).

In **DCPF** network losses have a nonlinear relationship with active power flow. This relationship can be formulated as follows [2.27]:

$$Ploss_k = r_{ij} P_k^2 \qquad (2\text{-}7)$$

This nonlinear relationship is not compatible with the linear **DCPF** model. Further, generation should compensate for local losses. As network losses depend on the loading of the transmission line, an iterative assessment of generation output would be required to ensure the power balance equation in (2-6) is satisfied. A few methods exist to incorporate a linearised model for network losses in the **DCPF** [2.28]-[2.29], improving the accuracy of the assessment. However, these methods add complexity to the problem and can often result in a larger network model, reducing the computational efficiency of the **DCPF**. If losses are neglected in the **DCPF** model, all active power injections are known in advance and the **DCPF** problem does not need iterations in the calculation.

The **DCPF** is often used for techno-economic studies and has been widely utilised in transmission planning [2.30]-[2.32] and for analysing market applications constrained by network congestion; for example, in calculating locational marginal prices [2.33]. Further the **DCPF** is used by National Grid as a basis for calculating transmission network use of system charges for the GB system [2.34]; network losses are assessed posterior using (2-7) [2.34]. It is generally regarded for long-term transmission planning, that the **DCPF** model is a satisfactory method. However, the final proposed network solution derived using a **DCPF** should be checked against an **ACPF** model (full or linearised) to assess the plan against further operational criteria. Reactive compensation or line additions/upgrades could then be suggested and incorporated into the final plan to ensure a secure network solution.

The **transportation model** is a simplification of the **DCPF** model, where all other constraints apart from the nodal balance limitation (2-6) are relaxed. The **transportation model** can be used to estimate power flows between regions of a system. The Energy Hub concept – where a hub can represent multiple energy carriers in an area (which can be converted, conditioned or stored subject to constraints) and be used to interface between different energy infrastructures and/or loads – effectively uses a transportation model to estimate the flows of energy between each hub [2.35]. Energy hubs can be used to combine energy infrastructures (such as gas and electricity) in an overall optimisation to reduce infrastructure investment, and provide a new vision for a future energy system. In transmission planning, the transportation model has been used in some studies to find transmission corridors which can be considered as candidates for transmission expansion before being assessed using a **DCPF** or **ACPF** model [2.24].

### 2.2.3. Planning in a Deregulated Power System

The electricity supply industry during the last 20-30 years, in many countries, has moved from a vertically integrated system where generation and networks are planned and operated by a single establishment, to an unbundled system where generation, transmission and distribution sectors are under the control of different registered companies. This is to encourage – through competition and the inclusion of cost penalties – economic and efficient planning and operation of electrical supply to reduce costs to the network customer. For the generation sector this deregulated, non-discriminatory, competitive environment gives generators an equal chance to enter the market place and trade energy, which should lead to generators offering their minimum price for production.

In the UK, following deregulation, TNOs currently still have a monopoly in the design, planning and investment of the network for which they own. National Grid is currently a TNO and operator for the transmission network in England and Wales. Ofgem, an independent regulatory body for the UK, ensures that network customers are not overcharged for using or connecting to the system, by setting the maximum amount of revenue that can be recovered from suppliers through price control periods for the transmission and distribution system [2.36]. For electrical transmission and distribution, the current price control period is from

2013 to 2021 [2.36]. Around £7 billion and £15.5 billion of investment has been earmarked for this price control period for Scotland and the England and Wales HV network respectively [2.36]. This is to encourage efficiency and innovation in network design and operation to maintain a reliable and secure supply. TNOs are responsible for creating and designing transmission reinforcement solutions which, if the solutions require a high level of investment, should be approved by the regulatory body. In the UK, the TNO has the final say on where and when to invest in the network; however, the TNO is unlikely to go against the recommendation of Ofgem particularly as this will likely reduce the revenue return that the TNO will make during the price control period.

Ofgem recently carried out the Integrated Transmission Planning and Regulation (ITPR) project to consider the arrangements for planning the transmission system. This was driven by the near term need for major network reinforcement under a changing energy mix. To ensure that the network is developed in an efficient, coordinated and economic way under the current deregulated setup in the UK, the project concluded that the following changes needed to be made [2.37]:

1. The SO will be given additional responsibilities to identify the need for transmission investment, and coordinate and develop reinforcement options; and
2. Competitive tendering will be extended to new, separable and high value onshore transmission network assets.

These changes will effectively reduce the monopoly that TNOs have on the Main Interconnected Transmission System (MITS). The market for network infrastructure is to potentially become more accessible for other organisations, out with the existing TNOs, to design and install network assets directly on the MITS. Further, conflicts of interest may arise between the TNOs and the 'enhanced SO' and Ofgem will need to ensure that National Grid as the 'enhanced SO' do not abuse their increased power in the electrical supply industry, and overcharge network customers.

In a deregulated power system, planning the transmission system is more challenging as a result of a changing generation mix dictated primarily by a potentially fluctuating energy market. The transmission network must be economically, technically and efficiently designed to allow for uncertainty in generation connection. Generation which was previously contracted (and therefore had a signed connection agreement with the TNO and SO), might not get the required consents for connection, or might pull out of the connection agreement with the TNO and SO during construction of the network reinforcement. Further, due to a potential long lead time for major transmission reinforcement, generation that was not considered in the reinforcement proposal might apply for connection and connect by the time the project is constructed and established on the system. Transmission reinforcements therefore need to be economical against a range of plausible generation scenarios.

Since February 2011 generation has been allowed to connect to the GB transmission system on completion of associated enabling works, ahead of any works required on the 'wider' MITS under the NETS SQSS. This 'connect and manage' approach is likely to increase network congestion on the GB transmission network and cause an increase in constraint costs arising from the bid and offer pricing of generation in the balancing market to match generation and demand across the GB system. It has become ever more apparent in the UK under an increasingly deregulated system that the trade-off between the CAPEX of a major reinforcement proposal and the associated alleviation of constraint costs, assessed against multiple generation scenarios, is the best way of validating the economic viability of a wider MITS reinforcement proposal.

As well as the alleviation of network constraint costs, other objectives can be considered in transmission planning under a deregulated liberalised generation market. Maximising the reliability of supply (as discussed in section 2.2.1) is key to minimising load curtailment and several studies have been carried out which include the cost of load curtailment as an objective function in transmission planning [2.38]-[2.39]. Further to this, maximising social welfare for consumers and generators is a potential key objective for consideration in transmission planning. This relates to the income accrued by generators and the benefit accrued to consumers in the lead up to market settlement where the generators offer for supply equals the consumers bid – this is known as the market clearing price (MCP) [2.40]. De La Torre *et al*. [2.41] uses an evaluation of social welfare as a measure of the success of a transmission network expansion proposal. Shrestha *et al*. [2.42] compares transmission expansion planning of a centralised and decentralised power system, considering the resultant social welfare as the main criteria. Minimising network constraints is intrinsically linked to maximising social welfare. Network constraints can prevent perfect competition between market participants (related to demand or generation); hence constraint alleviation is a prerequisite to a more competitive electricity market.

The dynamic, multi-criteria nature of the transmission planning problem against the uncertainty of generation capacity and demand, a consequence of a deregulated power system, is a complex problem. The next section details the co-ordinated method that the TNOs and SO employ – under the jurisdiction of Ofgem – to plan the GB transmission system in an economic and efficient way, for the purposes of providing value for money to the network customer and a secure reliable supply.

## 2.3. *Coordinated GB TNO/SO Transmission Planning*

Under BETTA, National Grid as SO was required to produce on an annual basis, with aid from the GB TNOs, a 7-year network plan for the GB National Electricity Transmission System (NETS) in the form of the NETS Seven Year Statement (SYS). This was primarily for assisting existing and prospective new users of the NETS, mainly from the generation sector, in assessing opportunities for using the system under the competitive deregulated GB electricity market [2.43]. The generation background on which the network was planned consisted of existing and proposed generation projects that had a signed connection agreement with the TNOs and SO. Demand across the GB system was mainly forecasted by National Grid.

Contracted generation projects can still fail in getting the required environmental planning consents for connection, or indeed may pull out of the arrangement on account of a change in government subsidy arrangements if it is a renewable generator. Hence, a contracted generation background is still uncertain. Since 2012, the NETS SYS has been replaced by an annual 10-year network plan in the form of the Electricity Ten Year Statement (ETYS). The primary purpose of ETYS is to outline the future transmission network requirement of the GB NETS in the form of power transfer capability [2.44]. The network requirement is assessed against a range of future needs defined by the Future Energy Scenarios (FES); developed in parallel with ETYS on an annual basis by National Grid. As opposed to a contracted generation background, the scenarios in FES currently outline four different perspectives on the contracted case. This helps to consider the uncertainty in generation outlook when planning the GB transmission system. Four scenarios are outlined in the 2015 FES statement [2.45]:

- **Gone Green**: this is a scenario which assumes a high level of prosperity to enable a high penetration of new more efficient technologies in the domestic and industrial sector. A high level of green ambition is assumed and new policies introduced to reduce $CO_2$ emissions. The scenario depicts significant decarbonisation in the electricity supply sector through adopting high levels of renewable generation (10GW of additional wind generation by 2020) and CCS. This is required to meet the 2050 UK governmental target of an 80% reduction in $CO_2$ emissions from 1990 levels by 2050 and is achieved in line with the UK legally binding carbon budgets. This is against a high power demand as a result of increased electrical demand in the heat and transport sectors. A significant level of smart metering is deployed to mitigate the impact of this demand.

- **Slow Progression**: this scenario assumes a lower rate of economic growth than in Gone Green. Innovation is prioritised on renewable and low carbon technologies in the generation sector, and policies support the increased penetration of low carbon generation. However, build rates are slower than in Gone Green and newer, less established and more expensive technologies such as marine generation receive less investment. Gas and Nuclear generation is a more significant contributor, as opposed to CCS and wind generation in Gone Green. An increased level of micro-generation in comparison to Gone Green is envisaged, and a lower rate of increase in demand from the heat and transport sectors is foreseen. The 2050 $CO_2$ emissions reduction target is missed in this scenario but achieved at a later date.

- **Consumer Power**: this is a scenario which assumes relative wealth and an increase in consumerism and quality of life. Consumers and industrial and commercial users have money to spend and invest in innovative projects. For the electrical sector this results in a more decentralised power system, with a high penetration of localised generation, particularly micro-CHP, by 2020 and beyond. High levels of large and small scale solar photovoltaic is predicted; 18GW of installed capacity by 2020. A high rate of increase in demand from the heat and transport sectors in comparison to Slow Progression is envisaged, as consumers purchase innovative products to improve the quality of life rather than to reduce carbon emissions – a high uptake of air conditioning units is described. Thus, the scenario stays on course to meeting the 2050

80% $CO_2$ emissions reduction target up until 2030 before progress is halted and the target is ultimately missed.

- **No Progression**: this scenario prioritises security of supply at minimum cost. Low economic growth leads to the domination of traditional sources such as gas and nuclear in electrical supply; gas generation makes up 35% of total installed generation capacity by 2020. Consumers choose to invest in technology with immediate and direct benefits. Thus, there is a low uptake of micro-generation, electric vehicles and smart appliances. Electrical demand therefore continues to increase but at a slower rate than the other three scenarios. This scenario misses all environmental government targets, and therefore fails to achieve all legally binding carbon budget targets.

In general, contracted transmission connected generation with environmental consent, a government subsidy (if applicable) and a near term connection date is included at the connection date for all four scenarios. However contracted generation without environmental consent or a government subsidy (if applicable) is treated differently for each scenario, and this forms the basis of the trend in large-scale generation for the first 7 – 10 years of each scenario. In general, Gone Green may assume a year delay to the contracted connection date, Slow Progression and Consumer Power may assume a two-year delay – 9GW of additional wind generation by 2020 is therefore assumed for Slow Progression as opposed to 10GW for Gone Green [2.45] – and No Progression may assume a 3 – 4 year delay in some cases and no connection in other cases to match the scenario ethos. Hence all four scenarios have a reduced transmission network requirement in the first 5-7 years of the ETYS ten-year horizon, then a strictly contracted generation background as previously planned against under the NETS SYS.

The transmission network requirement for each scenario is determined for ETYS against design criteria under planning timescales for the MITS, according to section 4 of the NETS SQSS [2.9]. Under section 4, the capability of the GB transmission network in relation to steady state voltage, voltage step change, thermal loading and system stability is required to be assessed against any applicable N-1, N’-1 or N-D fault outage (as described in section 2.2.1). The requirement and capability of the GB MITS is assessed by the TNOs and SO using boundaries to split the system. The next section describes this process.

### 2.3.1. GB Network Capability and Transmission System Boundaries

To assess the requirement and capability of the GB transmission system, the TNOs and SO split the system into several zones using boundaries. These boundaries have been defined and agreed by the TNOs and SO over many years and cut across the weakest circuits in the system for the transfer of power (export or import). Network issues which arise on these circuits, and on the MITS within the zone encompassed by the associated boundary, can limit the capability of power transfer across the boundary.

Both local generator and wider system boundaries can be defined on the system. For a local generator boundary, generation in the zone of the boundary is not diverse and is more than the zonal demand. Local generator boundaries are all therefore net power export boundaries. Wider system boundaries on the other hand contain a diverse portfolio of generation in the zone and can be net importers or exporters depending on where they are located in the GB system. Figure 2-1 details the current defined wider system boundaries and local generator boundaries for the purposes of ETYS. From Scotland down to England and then over to Wales boundaries B3b, EC1, EC3, EC5, NW1, NW2, NW4 and SW1 are defined as local generator boundaries [2.44].

The NETS SQSS specifies methodologies for assessing the requirement and capability of wider system boundaries and local generator boundaries. For local generator boundaries generation within the zone is set at its Transmission Entry Capacity (TEC) or at a level expected to arise during the course of a year of operation. For wider boundaries generation is selected and scaled according to the security and economy criteria defined in the NETS SQSS [2.9]. Under both criteria demand is set at ACS winter peak demand. A description of both criteria is provided below:

- **The Security Planned Transfer Criterion**: this criterion ensures that demand can be met securely without reliance on intermittent generation or interconnector imports. No output from intermittent generation or import from interconnectors is therefore assumed in the calculation. A ranking order of generation at winter peak is then used to determine the conventional generating units that are most likely to operate at ACS winter peak demand to achieve a margin of plant against demand which is ≤ 20%. This calculation is based on generator TEC. The output of the remaining contributory generators is then scaled uniformly to meet demand.

This image has been removed by the author of this thesis for copyright reasons

**Figure 2-1 Wider System Boundaries and Local Generator Boundaries on the GB Transmission System (source [2.44])**

- **The Economy Planned Transfer Condition**: this criterion was incorporated into the NETS SQSS to consider the requirements to develop the transmission network under increasing volumes of intermittent generation. The criterion aims to define a boundary requirement that if met would result in an efficient trade-off between the network reinforcement cost and the costs from generator constraints. To apply the criteria direct scaling factors are applied to some generation to minimise marginal cost (while considering intermittency of some generation). A variable scaling factor is then applied to the remaining generation so that total generation output equals ACS winter peak demand (see Chapter 4 for a detailed description of the methodology).

Following the calculation of planned transfer, the required transfer for the security and economy condition is then calculated by the application of the interconnection allowance and boundary allowance respectively. This is to provide a margin for error to consider generator unavailability or variations in demand across the system. With the continued move in the UK to a low carbon electricity system, the security planned transfer criterion will need modifying to reflect modern developments in generation, demand and interconnection.

The required transfers against the security and economy condition are assessed in ETYS for each wider system boundary over the timeline of the FES. The condition which results in the highest boundary transfer for any given year is defined as the requirement on which the network should be planned to meet. Currently, due to the amount of renewable generation proposed to connect to the GB system, the requirement for reinforcement of most wider system boundaries is based on the economy condition.

The power transfer capability of each wider system boundary is assessed over the ETYS ten-year horizon and compared against the defined requirement of the boundary. If the capability is significantly lower than the required transfer then this signifies the need for local network reinforcement of the MITS. The capability of a wider system boundary is assessed by proportionally scaling generation and demand either side of the boundary such that the transfer across the boundary circuits (import or export) increases. Under planning timescales as described in section 4 of the NETS SQSS, generation and demand is proportionally scaled until a pre-fault MITS power transfer limitation (related to steady state voltage, thermal loading or system stability) exists on the intact system or a post-fault power transfer limitation exists after applying a fault outage. The most onerous fault outage could be an N-D contingency, N-1 contingency or N'-1 contingency (in NGET's transmission system), as described in section 2.2.1, depending on the boundary under study.

As Gone Green is the most onerous of the FES scenarios and achieves governmental emissions targets, the TNOs determine boundary capability against the Gone Green generation and demand background. Network reinforcements are proposed by the TNOs to achieve an uplift in boundary capability against the section 4 design requirements and section 5 annual operational requirements of the MITS in the NETS SQSS. The reinforcement proposal could achieve an uplift which will result in a boundary capability which is greater than or equal to the required transfer; however, this reinforcement needs to be economical. To determine this, seasonal boundary uplifts provided by the TNO as a result of a reinforcement proposal against section 5 NETS SQSS annual operational requirements, are used in a Cost Benefit Analysis (CBA) carried out by the SO.

Recently, along with ETYS and FES it has become a new licence obligation under National Grid's 'enhanced SO' role as a result of the ITPR project to publish an annual Network Options Assessment (NOA) report [2.46]. The TNOs are required to provide reinforcement options for boundaries in their area, along with profiles of capital expenditure, an estimation of the Earliest In Service Date (EISD) for establishing the reinforcement (given recommendation from the SO in the NOA report), and boundary uplifts for the winter, summer, spring/autumn and summer outage season. This is to provide an indication of how the reinforcement performs across the year against different levels of demand and during any planned outages on the network for maintenance or to establish a new network asset. The SO is required to identify a preferred option or reinforcement strategy based on a CBA. This is an annual process, which should lead to an economic, coordinated and timely progression of transmission reinforcement on the MITS and answer the three questions in relation to dynamic planning: Where? What? and When?

The SO CBA involves a 40 year constraint cost forecast, with and without the reinforcement option, which leads to a recommendation of which option to invest in. The SO CBA methodology for the NOA process is summarised in the next section.

### 2.3.2. GB SO CBA methodology for the NOA process

The CBA for the NOA process compares the forecast capital costs, submitted by the TNO for each network option, and the monetised benefits over the lifetime of the reinforcement option to obtain an investment recommendation. A single year regret decision making process is carried out to assess the economic need for each reinforcement option in the coming year, and a recommendation on whether to proceed or delay the project is made. A description of the SO CBA methodology is described in the NOA methodology report [2.47] and is summarised below.

The country is split into regions and a reinforcement option is placed in one region only. All FES scenarios are considered in the analysis and other sensitivities, such as a local contracted generation background, can be considered. The CBA process for each region and each scenario under study is carried out in isolation. The CBA process is iterative and involves incrementally adding a single reinforcement at a time before evaluating the associated impact on the constraint cost forecast. The GB SO currently uses an Electricity Scenario Illustrator (ELSI) constraint modelling tool to forecast constraint costs under different scenarios and network capabilities. The ELSI tool uses a range of data from 20 year forecast data of fuel price, generation ranking orders (in the summer and winter), the cost of $CO_2$ emissions, and system marginal prices for markets abroad, to historic data on zonal wind load factors, demand data (peak, zonal distribution and load duration curve), plant characteristics (efficiencies, seasonal availability and bid/offer costs) and maintenance outages (duration by wider system boundary). The ELSI tool is an excel spreadsheet based model which does not explicitly model the GB transmission system. The ELSI tool estimates the seasonal output of generation using some of the data described above, and compares this against quoted base boundary capabilities and seasonal boundary uplifts for each reinforcement, as submitted by the TNO, to provide an estimation of network constraints.

Firstly, the ELSI tool is used to assess constraints against the base capability of the network to determine which boundaries within the region require reinforcement and when. This information then determines which reinforcement, from the TNO submitted list, should be evaluated first. The capability uplift of this reinforcement is then added to the boundary at the EISD of the option, and the constraint cost forecast for the base case and the reinforced case are compared. If multiple options exist for the boundary then this process is repeated for each reinforcement option. Each transmission asset is assumed to have a 40-year asset life and the constraint costs for years 21-40 are assumed to be identical to the ELSI calculation for year 20. The base case constraint cost forecast and the reinforced constraint cost forecast are discounted to present values and the capital cost of the reinforcement is amortised over the 40-year asset life via a weighted average cost of capital before also being discounted to present value. The amortised cost of the reinforcement is then added to the reinforced constraint cost forecast and compared to the base case constraint cost forecast to give the Net Present Value (NPV) of the reinforcement. The CBA NPV calculation can be formulated as follows:

$$NPV(i, N) = \sum_{t=0}^{N} \frac{(RCC_t + WACC_t) - BCC_t}{(1+i)^t} \tag{2-8}$$

where *t* is the year; *i* is the HM Treasury's Social Time Preferential discount rate used in the CBA to convert back to present value; *N* is the total number of years (in this case 40) and $RCC_t$, $WACC_t$ and $BCC_t$ is the reinforced constraint cost forecast, weighted average reinforcement capital cost and base case constraint cost forecast respectively for the year *t*.

For the purposes of carrying out single year regret analysis, the NPV of the reinforcement is also assessed for the possibility of the reinforcement being delayed by a number of years. This clarifies the optimum year for the reinforcement, for the scenario under study. From a set of candidate boundary solutions, the reinforcement with the earliest optimum year should be chosen. The boundary capability of this reinforcement is then added to the base case and another reinforcement option is then chosen for evaluation using the ELSI tool. This process is repeated until no additional reinforcements provide a negative NPV. In the end a list of reinforcement options, for the current region and scenario, is provided with an optimum year for each. Critical reinforcements are then derived from this list, where in any scenario (FES scenario or sensitivity) the optimum year is such that it could not be met if the project was to be delayed from the EISD by one year.

A single year least regret decision making process is then carried out by the SO which evaluates all permutations of the critical reinforcements – in this case the permutations are to proceed or delay the project for the current year, until the next NOA assessment. If there is more than one critical reinforcement option in the region then the number of permutations increases. Cost implications are applied for each permutation. An assessment of the present value of each permutation and scenario combination, considering operation and capital costs, is then carried out and a regret cost is calculated for each permutation and scenario, against the permutation with the lowest present value for the same scenario. Hence, one permutation will have a zero regret cost for each scenario. A worst regret cost is then found for each permutation by determining the largest regret cost against a scenario and the permutation with

**Table 2-1 Example Decision Tree of Single Year Least Regret Analysis (source [2.47])**

| Permutation | Options | Capital Cost (£million) | Scenario | Completion Date[1] | Regret (£million) | Worst Regret (£million) |
|---|---|---|---|---|---|---|
| A | Proceed Reinforcement 1 | 20 | A | Proposal 1: 2018<br>Proposal 2: 2020 | 51 | 51 |
| | Delay Reinforcement 2 | 1 | B | Proposal 1: 2018<br>Proposal 2: 2022 | 0 | |
| | | | C | Proposal 1: 2025<br>Proposal 2: N/A | 5 | |
| B | Delay Reinforcement 1 | 2 | A | Proposal 1: 2019<br>Proposal 2: 2019 | 102 | 102 |
| | Proceed Reinforcement 2 | 10 | B | Proposal 1: 2019<br>Proposal 2: 2022 | 35 | |
| | | | C | Proposal 1: 2025<br>Proposal 2: N/A | 10 | |
| C | Proceed Reinforcement 1 | 20 | A | Proposal 1: 2018<br>Proposal 2: 2019 | 0 | 15 |
| | Proceed Reinforcement 2 | 10 | B | Proposal 1: 2018<br>Proposal 2: 2022 | 2 | |
| | | | C | Proposal 1: 2025<br>Proposal 2: N/A | 15 | |
| D | Delay Reinforcement 1 | 2 | A | Proposal 1: 2019<br>Proposal 2: 2020 | 153 | 153 |
| | Delay Reinforcement 2 | 1 | B | Proposal 1: 2019<br>Proposal 2: 2022 | 32 | |
| | | | C | Proposal 1: 2025<br>Proposal 2: N/A | 0 | |

[1]The optimum years in this example for reinforcement proposal 1 and 2 is 2018 and 2019 respectively for scenario A, 2018 and 2022 for scenario B, and 2025 and N/A (i.e. not a viable solution) for scenario C.

the least worst regret cost is chosen as the recommended reinforcement investment decision. Table 2-1 details an example decision tree of this process [2.47]. Permutation C in Table 2-1 is found to have the least worst regret. In this case the recommendation would be to proceed with both reinforcement proposals for the current year.

## 2.3.3. Discussion on the GB TNO/SO Transmission Planning Method

In splitting the system into zones and assessing network limitations and reinforcement uplifts across boundary circuits, there is a risk that some network limitations within the zones are not picked up in the TNO technical analysis or in the SO CBA. If a network limitation occurs just on the other side of a boundary this limitation might not limit the adjacent boundary in the direction of power flow on the system. Consequently, a reinforcement proposal to alleviate this network limitation might not achieve a significant uplift on either wider system boundary, and thus this proposal will not perform well in the SO CBA. In relation to this, the ELSI tool used to assess constraint costs, does not explicitly model the GB transmission system. Hence constraints on the system may exist within the zones that are not being modelled and included in the SO CBA assessment.

Further to this issue, the technical analysis performed by the TNO and the SO economic assessment is separated. Hence in proposing a reinforcement, the TNO is unsure as to what size of seasonal boundary uplift is required and therefore what £/MW uplift is sought after for SO approval in the NOA process. This could lead to the TNO proposing more expensive solutions to achieve bigger boundary uplifts which aren't economically required for the scenarios under study. This in turn could waste time in planning the system as the TNO would then have to provide the SO with a more incremental, lower cost, reinforcement solution for SO recommendation in the next NOA report.

Network requirement is currently assessed against the design criteria outlined in section 4 of the NETS SQSS under the security or economy condition, but seasonal boundary uplift is determined against operational requirements in section 5 of the NETS SQSS for the purposes of the SO CBA. The operational requirements relax steady-state voltage limits across the GB system and for some areas of the network (where demand within the zone of a boundary is less than 1500MW [2.9]), the contingencies on which the network is to be designed against are lessened (exclusion of N-D contingencies). Thus, a MITS reinforcement proposal designed to adhere to the criteria of section 4 and increase boundary capability to meet requirements, might not perform well under a section 5 technical study and in the SO CBA.

There is evidence in the ETYS publications when comparing boundary requirement against capability under NETS SQSS section 4, that a significant gap is emerging, with requirement often exceeding capability well within the ten-year planning horizon. This shows a clear indication to reinforce however it is possible that solutions submitted by the TNO in the past have not performed well against the SO CBA. Further, this could be a result of the 'connect and manage' approach (as described in section 2.2.3) currently adopted in the UK, and TNOs subsequently seeking derogation from Ofgem or the SO from the obligation to comply with section 2 (outlining generation connection criteria) of the NETS SQSS to connect generation earlier. However, as most boundaries in the GB system have a higher requirement under the economy condition – and capability under NETS SQSS section 5 is therefore assessed against the economy planned transfer condition (applied to the Gone Green background) – the sizeable gap emerging between requirement and capability could also signify that the direct scaling factors employed under the economy condition may need to be reviewed.

Combining the creation of transmission reinforcement plans with a CBA assessment which explicitly models the network, and the associated constraints, to find an optimum solution could eradicate the issues discussed above and improve the efficiency of network planning in the UK system. Further, currently the TNO/SO method of transmission planning uses a classical form of multi-objective optimisation whereby the conflicting multi-objective problem of capital cost and network constraint cost has been converted into a single-objective optimisation. The amortised capital cost of the reinforcement proposed by the TNO used in the ELSI tool currently includes an estimation of the operation and maintenance cost of the reinforcement across its lifetime, and an estimation of the network outage cost needed to implement the reinforcement solution. These costs could be separately considered along with the capital cost and network constraint cost in a true multi-objective optimisation, where all cost objectives are considered to be of equal importance, to study the associated conflicting nature of these objectives.

As stated in Chapter 1, the benefit of this multi-objective approach to transmission planning for the GB TNO and SO could be twofold. By investigating objective trade-offs, the TNO and SO would have a better understanding of the positive and negative effects that can result from investing more or less into the transmission network, encouraging or discouraging further network investment. Secondly, if the creation of reinforcement plans is combined with a CBA assessment as discussed above, then reinforcement strategies created from a multi-criteria analysis, due to the unweighted nature of the objectives, may give the TNO and SO a number of reinforcement possibilities for different planning goals, which may not have been considered.

Many models and approaches which utilise mathematical and heuristic techniques to locate economical network reinforcement and expansion solutions have been proposed. Heuristic techniques are better suited and are more efficient at carrying out multi-objective optimisation without the need to simplify the problem to a single-objective optimisation. The next section summarises the key multi-objective heuristic approaches and techniques used in transmission planning and illustrates the associated limitations of many of the approaches in relation to the objectives of this thesis.

## 2.4. *Multi-objective Meta-Heuristic Techniques applied to Transmission Planning*

As introduced in Chapter 1, there have been many models and approaches proposed to solve the transmission planning problem. Specifically, many Transmission Expansion Planning (TEP) models exist, which look at the expansion of the network to new nodes (primarily for the connection of generation). Two extensive reviews on TEP models in 2003 [2.48] and 2013 [2.49] have been carried out. One of the drawbacks highlighted by Latorre *et al.* [2.48] was the lack of a coordinated generation expansion and TEP model (GE-TEP). Recently there has been a growing trend in the number of coordinated GE-TEP models to optimise the overall system, and a review into these approaches has been recently carried out by Hemmati *et al.* [2.50].

This coordinated form of planning however assumes that the generation and transmission sectors are not completely separated from one another; hence one of the studies carried out assumes a regulated electricity market [2.51]. Coordinated GE-TEP has also been investigated in a restructured power system, where there is a formation of a joint energy and transmission auction market [2.52]. In the UK system, a move back to a regulated system, or a restructuring of the current market, is unlikely to happen in the near term, particularly with the current move to a 'connect and manage' approach to facilitate the earlier connection of generation in a deregulated environment.

The techniques proposed for TEP fall into two broad categories: mathematical and heuristic. As a result of the three reviews carried out on TEP [2.48]-[2.50], and the multiple approaches adopted, the advantages and disadvantages of either technique are well understood. As summarised by Hemmati *et al.* [2.49], in general, mathematical techniques can efficiently find an accurate optimal solution, however, the conversion of the transmission planning problem and the associated network constraints into a mathematical optimisation model is difficult, and the complexity of the algorithm increases when applied to large scale transmission systems. Further, the mathematical procedure needs to be altered when inserting a new model constraint.

Mathematical optimisation methods are designed to solve specific problems and are best applied to solve linear, convex objective functions, where only a single optimal point – the global optima – exists. Hence these methods are better applied to single-objective optimisation and the simplified classical approach to multi-objective optimisation. Some mathematical methods can solve linear, convex, functions which involve thousands of variables efficiently. However, mathematical techniques encounter a great number of difficulties to locate the global optima when presented with a nonlinear, non-convex optimisation problem, akin to a true multi-objective optimisation, where more than one optimal point exists; known as local optima. Mathematical methods utilise a local search approach [2.53] which means that even if an optimal solution for a multi-objective non-convex problem is found, there is no assurance that the solution is the global optima and either a potentially suboptimal solution is accepted or a high computation time is required to find the true global optima.

Heuristic techniques are more straightforward to use and implement and adhere to a modular structure whereby new planning objectives and constraints can be easily considered in the optimisation. Further, network modelling can be carried out in a separate specialised power systems analysis package, with outputs fed back into the framework, as opposed to explicitly modelling the system within the optimisation procedure. Heuristic techniques are better suited than mathematical approaches to solving combinatorial multi-objective nonlinear and non-convex optimisation problems – the term combinatorial refers to locating an optimal solution from a discrete set of feasible solutions. They conduct a wider global search and are usually able to find a good approximation of the global optima [2.53]. However, there is no assurance that the heuristic approach finds the definitive global optima and computational time can be quite extensive. Heuristic techniques are therefore generally better applied for multi-criteria analysis of a power system under a long-term planning timescale, where a greater estimation on the future operation of the system is already implicit in the optimisation problem, and the need to quickly locate a definitive optimal solution is less.

As explained in Chapter 1, a meta-heuristic technique is a high-level problem-independent heuristic technique which can be used as a black box and therefore moulded to a wide range of optimisation problems. Many meta-heuristic optimisation methods have been used for TEP, as detailed in Table 2-2. The main advantages and disadvantages of each approach are detailed in Table 2-3.

### Table 2-2 Heuristic Optimisation Approaches applied to TEP [2.53]-[2.65]

| Heuristic Approach | Principle and method description |
|---|---|
| Ant Colony (AC) | Principle of using Ants behaviour to find a path between their colony and food source (nature inspired meta-heuristic, swarm based optimisation) – The use of artificial ants as software agents to explore the solution search space. Each ant moves at random from step to step and deposits a pheromone on its path. The greater the pheromone deposited, the higher the probability of the path being followed. This is a stochastic search but is biased by a local pheromone update performed by all ants after each step in the optimisation process to reflect the cumulative experience of the ant colony. The process stops when all ants have completed their 'tour' of the search space. |
| Artificial Immune System (AIS) – The Clonal Selection Algorithm (CSA) | AIS algorithms are a class of techniques which use the principle of the biological immune system and its ability to learn and memorise foreign cells or antigens when protecting the body (nature inspired meta-heuristic, evolutionary algorithm) – the CSA is a commonly used AIS technique and has been used in TEP [2.56]. This involves hyper mutation and the execution of small steps (leading to local optima) towards a higher affinity antibody (hab), as well as receptor editing which triggers large steps in the solution search space, which may locate the hab. The CSA technique resembles a genetic algorithm without the recombination or crossover operator (see genetic algorithm). |
| Artificial Neural Networks (ANN) | ANN models are a class of techniques which use the principal of biological neural networks and the central nervous system of an animal's brain (nature inspired meta-heuristics). Patterns are presented to the neural network via an 'input layer' which communicates to one or more neurons for processing via a system of weighted 'connections'. The neurons then link to an 'output layer' giving the optimisation result. An 'activity rule' is applied to define the interactivity of the neurons on a short-term time-scale, and a 'learning rule' is applied which modifies the weights of the 'connections' on a longer time-scale according to the input pattern. ANNs essentially learn by example. |
| Bee Colony Algorithm (BCA) | Principle of using the intelligent foraging behaviour of honey bee colonies (nature inspired meta-heuristic, swarm based optimisation). Artificial forager bee agents carry out a stochastic search to discover a population of good solution vectors to minimise the objective function of the optimisation problem. They then iteratively improve the solution vectors via a neighbourhood search. Poor solutions are abandoned. 'Scout' bees initially and randomly discover solutions to the prescribed problem. 'Employed' bees – associated with specific solutions – and 'onlooker' bees – which watch the movement of 'employed' bees within the hive to choose a solution – exploit the quality of the solution, developing a knowledge of previous solutions, and the 'employed' bee then becomes a 'scout' bee to locate better solutions until a predetermined maximum number of cycles is reached. |
| Differential Evolution (DE) | Principle of evolution, natural selection and genetics (nature inspired meta-heuristic, evolutionary algorithm). Similar process to the Genetic Algorithm (see description below). However, DE has a key difference in relation to the selection process in comparison to the Genetic Algorithm. Rather than selection being dependant on an assigned fitness value, all solutions or 'chromosomes' have an equal chance of becoming parents and producing solution 'offspring' for the next generation. New solutions are produced via a self-adjusting mutation operator, and after crossover, the new solution can compete with its own parent for inclusion in the next generation. |
| Fuzzy Programming (FP) | Principle is based on 'fuzzy' logic which is founded on 'degrees of truth' rather than binary decisions and reflects human linguistic categorisation – the aggregation of data into partial truths and then into higher truths. FP is the nondeterministic modelling of aspects of optimisation problems using parameters which have been imprecisely defined to reflect the imprecision of human judgement and the associated impact on the parameters themselves. |

**Table 2-2 Heuristic Optimisation Approaches applied to TEP [2.53]-[2.65]**

| Heuristic Approach | Principle and method description |
|---|---|
| Genetic Algorithms (GA) | Principle of evolution, natural selection and genetics (nature inspired meta-heuristic, evolutionary algorithm). GA's use a population of 'chromosomes', representing a possible solution to the optimisation problem, often generated from a pseudo random search. Fitness values are assigned to each chromosome based on the solutions performance against the objective functions. The fittest 'chromosomes' or 'parents' are selected and combined through a process known as crossover to produce 'offspring', which contain features or 'genetic information' from each solution. The worst performing solutions do not reproduce and are omitted from the gene pool. Mutation is applied at a predefined probability, to occasionally alter the genetic makeup of a solution and introduce new characteristics to the population.<br><br>The process of fitness assignment, selection, crossover and mutation is repeated from generation to generation, with the intention of creating solutions which are fitter than their predecessors. The size of the population is kept constant through the removal of bad performing solutions. Hence, the average fitness of the population increases when moving from generation to generation and eventually the fittest solutions might approximate the global optima. The process continues until a predefined maximum number of generations has been reached, or until the population converges to a single solution. |
| Greedy Randomized Adaptive Search Procedure (GRASP) | Principle of applying a 'greedy' logic whereby a locally optimal choice is made at each step or stage in the optimisation and the input data is not exhaustively utilised. GRASP involves a 'greedy' randomised solution construction phase and iterative improvements of the solution via a subsequent local search phase. An initial solution is built by adding elements from a restrictive candidate list which is constructed by checking and selecting each element in the full candidate list based on a 'greedy' randomised function value. The function value would either drive the inclusion of the best candidates according to the quality of solution they will provide, or drive a random selection from the candidate list. GRASP can therefore be described as a 'semi-greedy' heuristic. At each iteration, the candidate list is updated according to a local neighbourhood search. The process continues until a predefined number of iterations have been carried out. |
| Particle Swarm Optimisation (PSO) | Principle of the movement of organisms in a bird flock or fish school (nature inspired meta-heuristic). Another population based stochastic optimisation technique along with the GA and DE algorithm. PSO involves a swarm of particles, representing candidate solutions, moving in the solution search space. Each particle has a position vector and a velocity vector, derived from simple mathematical formulae, which dictates its movement. Further, each particle has a memory centre that stores its own best position in the search space and a global best position obtained from communication with neighbouring particles. It is expected as a result that the swarm of particles will move towards the region of the search space which has the best solutions. |
| Simulated Annealing (SA) | Principle of metal annealing – The optimum cooling down rate of molecules from a high-energy state (melting metal) to a low energy state (the formation of crystals) to form metal. SA is a pseudo random search in creating optimal solutions which uses a diminishing probability when altering solutions – simulating the cooling down stage – to escape from local optima. Only transitions to better solutions at a low probability are permitted to enable the location of the global optima. The process stops when the number of prescribed iterations has been carried out. |
| Tabu Search (TS) | Principle of human memory (nature inspired meta-heuristic). TS improves local or neighbourhood search through keeping a short-term memory or 'tabu list' of sub optimal regions of the search space, and a longer-term memory of transition strategies that improved the local search. TS is an iterative technique where initial solutions can |

**Table 2-2 Heuristic Optimisation Approaches applied to TEP [2.53]-[2.65]**

| Heuristic Approach | Principle and method description |
|---|---|
| | be generated randomly. Often the stopping criteria for TS is when the number of prescribed iterations has been carried out. |

**Table 2-3 Advantages and Disadvantages of Heuristic Approaches [2.53]-[2.65]**

| Heuristic Approach | Advantages | Disadvantages |
|---|---|---|
| AC | • Repeatable process.<br>• If successful then fast at discovering good solutions.<br>• Can be used to solve hard dynamic, combinatorial optimisation problems.<br>• Solution convergence is guaranteed. | • Applications tend to be experimental rather than theoretical.<br>• Time to solution convergence is uncertain.<br>• Sequences of random decisions make it unlikely for AC optimisation to find the global optima. |
| AIS (CSA) | • Can explore the solution space efficiently, through parallelisation, and effectively. | • Low affinity antibodies must be replaced with new random antibodies during the mutation process.<br>• Recombination or crossover to switch genetic material is not carried out (this is included in GAs). This effects diversity in the solutions generated and therefore reduces the likelihood of locating the global optima. |
| ANN | • Depending on the application and the strength of the patterns provided as an input, neural networks can be efficiently well trained for dynamic or non-linear optimisation problems. | • ANN learning happens independently and the user usually does not know of a networks progress prior to the output – a trained network.<br>• Computational time is extensive for very large networks to compute the function of each neuron and connection separately.<br>• Parallel computation is often required.<br>• The number of neurons required or the settings of the weights on the connections for the specified optimisation problem is unclear.<br>• Over-training in ANNs is a consistent problem. |
| BCA | • Can be used for constrained and combinatorial multi-objective optimisation problems.<br>• Only three control parameters are required to be predetermined by the user; population size, maximum cycle and number of trials (for 'employed' bees to improve their solutions before becoming 'scout' bees)<br>• Easy to implement, flexible and robust. | • Like other stochastic optimisation methods (i.e. AC or GA), a poor balance between exploration of the search space and exploitation – the ability to apply knowledge of previous solutions to look for better solutions – will often lead to premature convergence if excessively exploitive and slow convergence if excessively explorative. |

**Table 2-3 Advantages and Disadvantages of Heuristic Approaches [2.53]-[2.65]**

| Heuristic Approach | Advantages | Disadvantages |
|---|---|---|
| | • Found to have a comparable performance to the DE and PSO algorithms [2.57]. | |
| DE | • Similar advantages to the GA.<br>• DE has an improved local search capability compared to GA and as such it can be faster at converging to a global optima solution.<br>• Encoding of the 'genes' within each 'chromosome' or solution can be done using real values as opposed to requiring conversion to a binary or integer format (as in a GA) | • Similar disadvantages to the GA (excluding local search capability). |
| FP | • Often used in combination with a GA forming a hybrid meta-heuristic technique to reflect the 'fuzzy' nature of real life optimisation problems and to therefore incorporate an element of vagueness into the assumptions. | • Difficulty in defining the rules for applying 'fuzzy' logic. |
| GA | • Easy to implement, flexible in application, and can be used to solve non-linear combinatorial multi-objective optimisation problems.<br>• Efficient simultaneous exploration and exploitation from generation to generation via the mutation operator and the selection and crossover operators respectively to locate the global optima – easier than BCA to find a balance between exploration and exploitation.<br>• Can explore multiple regions in the solution search space simultaneously and efficiently through parallelisation across 'genes' within 'chromosomes' (as effective as AIS for parallelisation). This reduces the likelihood of being trapped in local optima.<br>• Encoding of the 'genes' within each 'chromosome' or solution can be done using binary or integer representation. | • No guarantee of finding the global optima.<br>• A large computational time is often required.<br>• A sizeable number of problem-specific parameters (particularly in comparison to the BCA) need to be adequately set for correct implementation. These are the initial population, population size, probability of crossover and mutation probability. If the population is too small, then diversity in the search space is limited and mutation becomes the key operator. Too large and computational time increases. If the probability of mutation is set to high, then the search can become too random in nature.<br>• GA is outperformed by other methods for linear, convex optimisation problems.<br>• Generally regarded as having a poor local search capability in comparison to DE.<br>• A local search algorithm such as 'hill climbing' or TS is often needed in combination with the GA as a hybrid meta-heuristic technique to start from the GA optimal solution and encourage convergence to the global optima, rather than the surrounding region. However, diversity would then be somewhat lost in the multi-objective optimisation. |

**Table 2-3 Advantages and Disadvantages of Heuristic Approaches [2.53]-[2.65]**

| Heuristic Approach | Advantages | Disadvantages |
|---|---|---|
| GRS | • Faster than most meta-heuristic techniques for combinatorial multi-objective optimisation problems and faster than some mathematical techniques such as dynamic programming for linear, convex optimisation problems<br>• Effective and efficient at locating good solutions and local optima. | • As GRASP is based on a 'greedy' logic and a local search, the algorithm is unlikely to converge to the global optima. |
| PSO | • Similarly to other meta-heuristic techniques, it is a flexible technique which can be applied to a wide range of multi-objective combinatorial optimisation problems.<br>• Can search a very large space of candidate solutions. | • Similarly to AC, BCA, GA or the DE algorithm, there is no guarantee of finding the global optima.<br>• The basic PSO method is particularly susceptible to being trapped at a local minimum in the optimisation – a sub-swarm is often required to be defined which ignores the entire swarms best position to move towards the global optima.<br>• The problem-specific parameters of the PSO have a significant impact on the optimisation outcome.<br>• The balance between exploration and exploitation, like BCA, AC, GA and the DE algorithm, is particularly key to the success of the PSO algorithm. |
| SA | • Easy to apply and good at finding reasonably good solutions for many combinatorial optimisation problems.<br>• Can be used in combination with a GA as a hybrid meta-heuristic technique to include the 'cooling down' principles of SA when accepting new populations, improving GA exploration in the search space. | • Cannot recognise when the global optima has been located – number of iterations is therefore a key parameter.<br>• Used as an approximation method.<br>• Often used in combination with TS as a hybrid meta-heuristic technique as a result of the above limitations. TS enables memory to be applied to the SA process to help define regions of the search space that have already been explored. |
| TS | • An improved local search algorithm which can locate good local optima solutions effectively for complex multi-objective problems.<br>• Often used in combination with other meta-heuristics (particularly SA or a GA) to improve the local search and potentially enhance overall performance. | • Very unlikely to locate the global optima when used in isolation.<br>• Slower than other local search techniques. This can limit its application in hybrid meta-heuristics. When used in combination with a GA each generation is slower, however fewer generations may be required to locate the global optima. |

Many of the meta-heuristic techniques described in Table 2-2 are inspired by nature, and within this subset there exists both swarm based and evolutionary approaches to deal with non-convex, nonlinear, combinatorial multi-objective optimisation problems. A multi-objective problem includes conflicting objectives. In the case of transmission planning, this could be the minimisation of investment, the minimisation of network constraints and the maximisation of social welfare (objective description in section 2.2.3).

There is no single Pareto-optimal solution in a true multi-objective optimisation. A solution is Pareto-optimal if it cannot improve in one objective without detriment to the other objectives: Pareto-optimal solutions are said to be non-dominated by any other solution [2.66]. Many Pareto-optimal solutions can exist in a multi-objective optimisation, defined by the Pareto set. A subgroup of the Pareto set is usually sought after which accurately reflects the Pareto set to minimise computational effort. To locate the subgroup, a multi-objective optimisation needs to satisfy the below three areas [2.61],[2.66]:

- **Accuracy**: the subgroup of solutions found need to be as close to the true Pareto set as possible; capturing the extent of the objective functions considered.
- **Diversity**: the solution subgroup needs to be as diverse as possible to obtain a more extensive set that is reflective of the true Pareto set.
- **Spread**: the solution subgroup needs to "capture the whole spectrum" of the Pareto set; exploring the edges of Pareto-optimality.

Evolutionary based meta-heuristic techniques utilise the structure of a typical GA (described in Table 2-2), with modified fitness assignment and selection operators designed to deal with a true multi-objective optimisation. These techniques are generally referred to as Multi-Objective Evolutionary Algorithms (MOEAs). MOEAs are powerful techniques which can construct and assess groups of possible solutions simultaneously through parallelisation – a similar benefit to the AIS approach – and therefore can find several Pareto-optimal solutions in a single "run" [2.61]. MOEAs are also able to locate a Pareto set for the multi-objective problem which satisfies the above criteria on accuracy, diversity and spread.

The better performing state-of-the-art MOEA techniques incorporate the concept of elitism to preserve non-dominated, Pareto-optimal solutions from generation to generation of population evolution. Non-dominated solutions are kept in a secondary elite population known as the 'external archive' to guarantee that these solutions are not lost through the crossover or mutation process. Further, the elite solutions from the old population participate in the selection and crossover process for the new population, which improves the computational efficiency of the algorithm in determining the Pareto set. Essentially, an elitist MOEA deterministically ensures that the best performing solution from the old population survives directly in the new population, unless an improved solution is found and replaces it [2.66]. MOEA techniques with elitism have been found to outperform non-elitist MOEA's [2.67].

The Strength Pareto Evolutionary Algorithm (SPEA) proposed by Zitzler *et al*. [2.68] in 1999 is considered the first MOEA technique to include elitism. After the SPEA, the use of 'external archives' in MOEA techniques became the standard and is now a defining characteristic of state-of-the-art MOEA [2.61]. It has been demonstrated since by Coello-Coello [2.69], that elitism is included in MOEA techniques to guarantee convergence towards the Pareto set. Figure 2-2 details the typical evolution of solutions in an MOEA towards the Pareto front. The Pareto front constitutes the objective values of the Pareto set.

Since the SPEA, the elitist MOEA techniques which have followed are based on a similar framework but differ in their procedure for fitness assignment and selection [2.70]. The Non-dominated Sorting Genetic Algorithm II (NSGA-II), developed in 2000 by Deb *et al*. [2.71], and the Strength Pareto Evolutionary Algorithm 2 (SPEA 2), developed in 2001 by Zitzler *et al*. [2.72], remain the most advanced and well recognised MOEAs, and have both been applied to a wide range of practical multi-objective problems. NSGA-II is simpler to apply than the

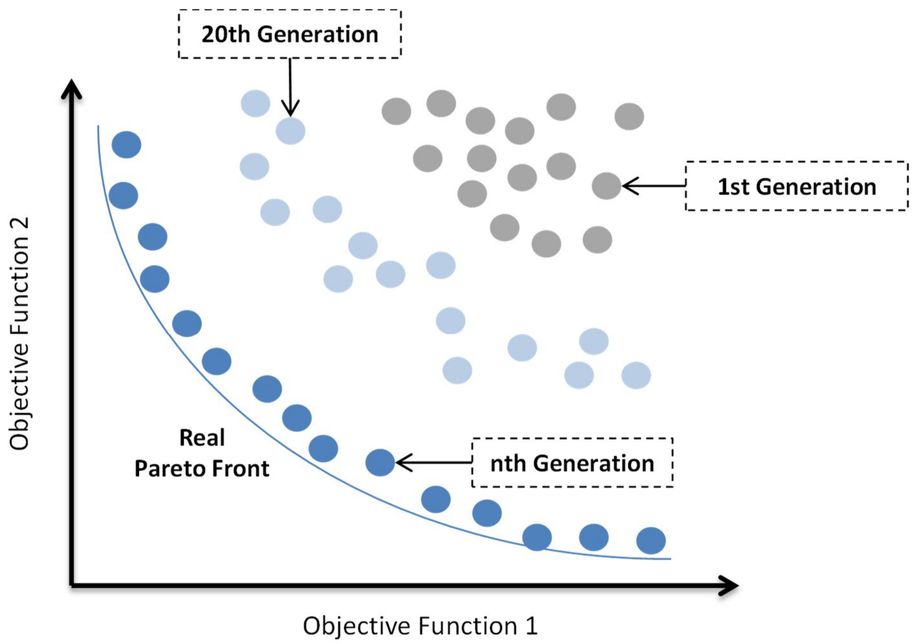


**Figure 2-2 Typical Evolution of an MOEA towards the Pareto Front**

SPEA2 as an 'external archive' is not explicitly used and elitism is included through maintaining non-dominated solutions in the overall population. Further, the fitness assignment procedure is based on the simplified concept of dominated ranking, associated with early MOEA techniques, whereby non-dominated solutions are given the same common ranking of highest fitness and solutions further away from the Pareto set are given a reduced ranking of fitness. The fitness assignment procedure therefore does not consider the distribution of the solutions.

The original SPEA, and subsequently SPEA2, considers the distribution of solutions in a more complex fitness assignment procedure which allocates a worse fitness to solutions in the Pareto set which are in crowded regions of the search space. This pushes the exploration towards less crowded, and therefore not sufficiently explored, regions of the search space and helps to obtain a well-spread Pareto set. For computational efficiency and solution quality, the SPEA2 has been found to compare well to the Pareto Envelope-Based Selection Algorithm (PESA) – another elitist MOEA – and the NSGA-II [2.72]. Further, Mori *et al.* [2.73] applied the SPEA2 and NSGA-II to a distribution network expansion planning problem, and demonstrated that the SPEA2 outperformed the NSGA-II.

The SPEA2 is a well-tested algorithm. As a result of its proven performance against other elitist MOEA techniques, the MOTREP framework proposed in this thesis uses the SPEA2 for the optimisation stage. Similarly to a meta-heuristic, the MOTREP framework (described in detail in Chapter 4) embraces modularity in its design. As such, the fitness assignment or selection procedure of the MOEA can be changed or altered to represent an alternative MOEA technique, without the need to update the entire transmission reinforcement planning framework. A detailed procedure of the SPEA2, developed in response to criticisms of the original SPEA (as described in Chapter 4), is included in Chapter 4 along with any required changes made to the algorithm, in particular to the crossover and mutation operator, for the purposes of the MOTREP framework. The SPEA2 algorithm has been successfully applied to many power system problems and an outline of these applications, and the problem specific design of some of these applications, is also included in Chapter 4.

The SPEA2 algorithm at the time of the work carried out in this thesis had yet to be applied to the transmission planning problem. Recently, the SPEA2 has been used in a long-term simplified TEP study [2.74] (as discussed in more detail in the next section). However, the algorithm is applied to a series of standardised and simplified network models as specified by Romero *et al*. [2.75] to test its performance. The algorithm, as with many other MOEAs, is therefore not applied to a large-scale multi-voltage network such as the GB transmission system. Hence, one of the contributions of this thesis and the MOTREP framework proposed is to facilitate the understanding of meta-heuristic techniques and their use in transmission network planning.

## 2.5. *Simplifications and Limitations of Current Meta-Heuristic Frameworks applied to Multi-Objective Transmission Planning in a Deregulated Environment*

As outlined in Chapter 1, the review by Latorre *et al.* [2.48] in 2003 highlighted several drawbacks from the available suite of TEP models. The lack of planning algorithms which included alternative reinforcement options to line addition such as redesigning, rearranging or line upgrading, or the inclusion of FACTS devices, was a significant drawback for the practical implementation of the models to a realistic planning problem. The updated review of TEP models in 2013 by Hemmati *et al*. [2.49] concluded that the consideration of FACTS devices in TEP has still not been properly investigated. Lower cost reinforcement solutions to line addition need to be incorporated into the planning algorithm if they are to aid transmission planners. In the case of the GB transmission system for instance, partly as a result of the 'connect and manage' approach and the increased management of network constraints, there is the current need in areas of the system for a more incremental low cost reinforcement solution to line addition or line rebuild.

As a result of the computational effort required to carry out a multi-objective optimisation using an iterative meta-heuristic technique, simplifications elsewhere to the transmission planning problem are often needed to be made. There is a balance between these simplifications and the benefit of carrying out a true multi-objective optimisation. Of the recent meta-heuristic techniques applied to multi-objective transmission planning, which consider the complexities of a deregulated environment – as is the case in the GB transmission system – there are several simplifications and limitations of the proposed frameworks. A review of these techniques is included below.

Of the recent meta-heuristic frameworks proposed [2.74],[2.76]-[2.81], which consider network constraints, and/or the associated costs from the electricity market, the majority use a DCPF model [2.74],[2.76]-[2.78],[2.80]-[2.81] for simplification of the network and the associated constraints, as opposed to an ACPF model [2.79] which could allow for the consideration of reactive power planning in the optimisation problem [2.79]. Further, the majority propose a static planning framework [2.74],[2.77]-[2.79],[2.81] as opposed to incorporating the multi-stage nature [2.76] or the dynamic nature [2.80] of the transmission planning problem. Some approaches only consider network congestion [2.74],[2.76]-[2.78] in the optimisation problem, as opposed to considering the associated cost impact from the electricity market, in this case the balancing mechanism [2.79]-[2.81]. Further, some approaches [2.74],[2.76] do not consider a deterministic or probabilistic criteria for security. Hence, the network expansions proposed are not tested against an N-1, N'-1 or N-D type contingency as per GB network security requirements (see section 2.2.1). However, some approaches consider a deterministic N-1 security criterion either in the form of an objective [2.80]-[2.81] or as a constraint [2.77]-[2.79] in the optimisation problem.

These approaches consider candidate line additions to existing network routes as well as to new nodes on the network, to expand and therefore reinforce the network under study. A summary of the frameworks proposed is included below.

- Maghouli *et al*. [2.76] proposes a multi-stage transmission planning framework (the test case is across three five-year stages) which utilises the NSGA-II meta-heuristic and incorporates a form of internal scenario analysis to include rapidly changing generation expansion plans (two generation scenarios are included in the test case) in a co-ordinated TEP-GEP approach. The minimisation of network congestion is included as an objective along with the minimisation of investment cost.

- Sousa *et al*. [2.74] presents a static framework for long-term transmission expansion planning utilising the SPEA2. The objectives considered are the minimisation of investment cost and the maximisation of 'satisfaction level' of an operation scenario created from a probabilistic model of generation dispatch: network congestion is not explicitly modelled. The primary aim of the framework is to locate the Pareto-optimal set and determine the minimum investment cost required to meet the 'satisfaction level' of all operation scenarios. The performance of the SPEA2 is compared against the NSGA-II.

- Wang *et al*. [2.77] proposes a static transmission planning approach which utilises the original SPEA – and therefore includes the inherent limitations of the algorithm in comparison to the SPEA2 (as discussed in Chapter 4) – and locates the Pareto set for the objectives of minimising investment cost, outage cost and congestion surplus: an index to measure the congestion degree of the transmission network. The framework proposed does not assess network expansion candidates against multiple scenarios, or incorporate generation expansion planning, such as the frameworks described above. However, a deterministic N-1 security criterion is implemented and solutions which do not achieve this security level are removed.

- Qu *et al*. [2.78] proposes a static TEP approach which utilises the Chaos Optimisation Algorithm (COA) – a meta-heuristic inspired by the nonlinear random phenomenon common in nature, which utilises the intrinsic stochastic property of chaos movement. The COA is used to solve the multi-objective problem relating to the minimisation of investment cost, the maximisation of transmission surplus capacity and the minimisation of the load factor of the network. The last two objectives could be deemed as not conflicting and therefore convex in nature.

- Hooshmand *et al*. [2.79] proposes a static framework which utilises the PSO meta-heuristic and incorporates reactive power planning into the optimisation problem. The optimisation problem involves the minimisation of investment cost and the maximisation of social welfare: a potential consequence of minimising network congestion. Network reliability constraints are considered in the form of an index on the Expected Energy Not Supplied (EENS) – this is the total amount of loss of load (MWh/year) – and an index on the Loss of Load Expectation (LOLE) – the total hours of loss of load (h/year). EENS is calculated using a Monte Carlo simulation to randomly allocate system load, based on a normal distribution, and to randomly select a line outage. The PSO algorithm is applied twice, whereby in the first stage the TEP problem is solved and new line additions are determined for network expansion, and in the second stage the reactive power planning problem is solved by adding reactive power sources. The sizing and location of reactive sources is considered in the optimisation problem.

- Foroud *et al*. [2.80] proposes a framework which utilises the NSGA-II meta-heuristic and considers the dynamic planning problem for network expansion. The optimisation problem involves the minimisation of investment cost and network constraint costs and the maximisation of network reliability. Network reliability is monetised in the approach through the consideration of an average load curtailment cost across the expansion and reinforcement solutions as a result of N-1 contingencies. Candidate line additions are added for each year in the planning horizon, as generation and demand is varied, and the objective functions are calculated for each solution in each year. The NPV of each objective is calculated over the planning horizon (5 years in the test cases).

- Maghouli *et al*. [2.81] proposes a static framework which utilises the NSGA-II meta-heuristic. The optimisation problem involves the minimisation of investment cost and congestion cost, and the maximisation of network reliability. A full N-1 deterministic security criterion is applied and the amount of load shedding as a result of each reinforcement or expansion solution is considered from the contingency analysis in the assessment of network reliability.

A trade-off analysis between the objectives studied is not performed for much of the approaches outlined above [2.74],[2.76]-[2.79]. This excludes one of the main benefits of utilising a meta-heuristic technique to perform a true multi-objective optimisation. The primary focus of these frameworks is to initially utilise the meta-heuristic to effectively and efficiently search for Pareto-optimal solutions, and to obtain and locate an optimal transmission reinforcement and expansion plan using either fuzzy decision making analysis [2.76],[2.81] or a ranking method based on Euclidean distance [2.77]. In some cases, following an attempted trade-off analysis, a clear trend between some of the objectives was unable to be defined [2.80]. However, in other cases clear trends and objective trade-offs could be obtained from the Pareto set [2.81] to form a better understanding of the multi-objective problem for the benefit of transmission planners.

Several simplifications and limitations exist which are common among the meta-heuristic frameworks proposed above for the purposes of multi-objective transmission planning in a deregulated environment. These are detailed below.

- The frameworks are applied to simplified single-voltage small-scale network models of the Iranian transmission system (a 55-node [2.76] or 10-node representation [2.80]) or the southern Brazilian system (a 46-node representation [2.74],[2.78]) or standardised small-scale single-voltage network models such as the Garver 6-node system [2.74],[2.78],[2.79] or the IEEE 24-node test case [2.74],[2.79],[2.80],[2.81]. Hence the applicability of the proposed approaches is not tested against a realistic transmission planning problem, and the complexities and limitations (i.e. power transfer capacity of the line) associated with each voltage level in a transmission system are therefore not considered.

- Line addition is the only reinforcement option considered to deal with thermal network constraints. Further to this, the capacity of the candidate line addition solutions is not varied in the optimisation. Hence, the approaches proposed are only designed and tested to fully explore one decision variable for reinforcement; location. However, transmission planning involves a combination of decision variables for reinforcement, which as well as location, includes size and type (or configuration). Cheaper alternatives to line addition need to be included as a reinforcement option to better reflect the complexity of the transmission planning problem.

- The assessment of network constraints or social welfare, and where included, the associated cost from the electricity market is carried out only at peak demand [2.77],[2.80]-[2.81], or a single instance of time [2.78]-[2.79], or at several points around peak demand (22 operational points [2.76]). This is a limited temporal assessment of a network expansion plans associated economic impact. As detailed in section 2.3, the GB TO is required to provide the GB SO with a reinforcements boundary uplift for the winter, spring/autumn, summer and summer outage seasons. The GB SO then assesses the reinforcement's performance all year around against the alleviation of constraints in a CBA. This is to consider high levels of network congestion which can often occur at low demand levels in the summer, due partly to planned outages of transmission lines. Further, as reinforcement plans are often designed to cater for peak demand it is important to assess the capability of a reinforcement against a different background of demand level and generation output.

- The frameworks proposed do not consider the alteration of the expansion/reinforcement plan during the optimisation, and the redesign and rearrangement of the associated reinforcements. If line upgrading/reconductoring is included as an option the ability to redesign reinforcements is crucial, particularly in cases where no line additions have been applied as part of the reinforcement plan. A reinforcement plan could exacerbate network issues, but a small adjustment to the plan could lead to a successful potentially Pareto-optimal solution. This could be more effective than simply excluding the reinforcement plan from the next solution population, and it gives the solution another chance to succeed.

- As a result of the above limitations, the frameworks proposed do not adequately assess the trade-off between network investment cost and constraint cost alleviation; a key conflict in a deregulated transmission system. Hence, the transmission planner is not sufficiently aided in better understanding this relationship, and the solutions produced may not be economically efficient on a practical system.

The MOTREP framework proposed in this thesis aims to solve the above simplifications and limitations from the current approaches to applying meta-heuristics for the multi-objective transmission planning problem in a deregulated system. As introduced in Chapter 1 and detailed in Chapter 4, the MOTREP framework is a systematic approach designed for application to a complex large-scale multi-voltage transmission network such as the GB transmission network. The framework incorporates a systematic planning algorithm to generate individual reinforcements and overall plans, as well as to alter reinforcements should they exacerbate network issues. The approach proposed caters for three variations in reinforcement characteristic; location, configuration (line upgrading/reconductoring, single-circuit and double-circuit addition) and thermal capacity. The framework proposed carries out a thorough exploration of each characteristic and assesses the reinforcement plans generated against several objectives. This includes an annual stochastic assessment of constraint costs, which includes planned summer outages of network assets, to provide an improved appraisal of a reinforcement plans impact and benefit to the base case network.

The MOTREP framework is a static flexible approach for the primary purpose of assessing the economic impact of a future energy scenario on the GB transmission system. The generation of realistic and economical reinforcement plans will improve the scenario assessment, and the associated multi-criteria analysis, and objective trade-off analysis, can aid transmission planners in better understanding the complex relationships between conflicting planning objectives. The modelling approach has been designed and developed to adhere to the thermal constraint criteria outlined in the NETS SQSS (section 2.2.1). These rules are specific to the GB transmission network and part of current planning practice, however the bulk of the methods used in the modelling framework are generic and can be applied to other multi-voltage transmission network planning problems.

## 2.6. *Chapter 2 Summary*

This chapter presents a detailed overview of the transmission planning problem, emphasising the multi-objective nature of the problem and highlighting the impact of deregulation to transmission planning. The current structure and the methods employed by the GB SO and GB TNOs to satisfy the transmission planning objectives of the regulator under the price control is outlined. Potential inefficiencies and technical limitations in the coordinated planning method of the GB TNO and SO are highlighted and a method which combines a CBA assessment in the creation of reinforcement plans is advocated. Meta-heuristic techniques which potentially could be used for this problem are subsequently reviewed, as are the associated frameworks and modelling approaches which have been designed to utilise meta-heuristics to solve the multi-objective transmission planning problem in a deregulated environment. The objective and scope of the proposed MOTREP framework has been developed from the limitations and simplifications of these techniques.

The MOTREP framework proposed in this thesis has been designed primarily for evaluating the economic impact of a future energy scenario to the GB transmission system. The next chapter reviews the models and approaches used in scenario evaluation for key UK-low carbon research studies.

## 2.7. *References for Chapter 2*


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# Chapter 3

# 3. UK Energy Scenarios and the Methods used for Creation and Evaluation

## 3.1. *Introduction*

The UK is a leading user of low carbon energy scenarios as a result of the country being the first to set legally binding greenhouse gas emission reduction targets through the Climate Change Act (2008). In the past ten years, there have been a large number and wide variation of energy scenarios, which have been created and evaluated using different methodologies. For the UK, this has involved a number of technical feasibility studies, with the aim to identify technologies that can supply energy and reach the associated carbon reduction target of the scenario, whilst adhering to constraints in the energy system. These technical feasibility studies have aspired to demonstrate the long-term emission reductions which can be achieved across sectors relating to transport (including international aviation and shipping) or the heating and powering of domestic, commercial and/or industrial users.

This chapter presents a review and discussion of influential future energy scenarios created for the UK energy system. A critical review is carried out on the methods and models used for scenario creation and evaluation. Multiple scenarios are often created under a low-carbon policy related study, and as such this chapter reviews, consecutively, each study as a whole. For each study, the methodology for creating the associated scenarios is detailed, the ethos of the scenarios is described and the associated targets and aims are depicted. Finally, the methods and models employed in scenario creation/evaluation are outlined. Comparisons are made between the UK low-carbon studies included in the review, and areas are highlighted where the analysis involved is overly simplified, both technically and geographically.

Prominent research projects such as *LENS 2050*, *DECC 2050*, UKERC's *Energy 2050* project and the *Transition Pathways to a Low Carbon Economy* (Phase one and two) project are reviewed in detail. The scope of these studies includes the UK energy or electricity system – sectors which relate to the objectives of this thesis.

## 3.2. *DECC 2050 Pathway Analysis*

The Department of Energy and Climate Change (DECC) developed an online interactive framework in 2010 known as the '2050 Pathways Calculator'[4], to help policymakers, industry and the public to understand the choices and changes required for the UK energy system to achieve an 80% reduction in greenhouse gas emissions by 2050. Users of the online tool could develop their own combination of levels of cross sector change to achieve the emission reduction target. Four different trajectories were included – pre-set in the underlying model – for each demand and supply sector considered. The user could select one of the four trajectories and the model would combine these trajectories to look for 'successful' pathways that deliver, overall, a secure energy system where supply meets demand and an 80% emissions reduction is achieved [3.1].

The supply sectors were made up of low carbon generation (ten sectors in total), where the remaining supply gap was filled by fossil fuel generation (coal, gas and oil) assumed to be available from domestic production or the international market. Energy demand was split into four sectors; lighting and appliances, heating and cooling, transport, and industry. Further, five non-energy sectors were included in the DECC calculator; waste, agriculture, land use (including land use change) and forestry, industrial processes, and negative emissions (involving technologies which aim to remove carbon dioxide directly from the environment i.e. biomass co-firing with CCS).

The trajectories were developed to achieve a level of consistency across different sectors relating to the level of change. For the energy supply sectors, the trajectory level ranged from a pathway which assumed little or no attempt to decarbonise the system (where unproven low carbon solutions are not developed or deployed), to a pathway which assumed an ambitious but reasonable level of change (with realistic build rates), a pathway which alleged a very ambitious level of change to the current system (with significant technological breakthroughs), and finally, a pathway which assumed an extreme level of change, pushing the physical and technical limits of what can be achieved. For the energy demand sectors, the trajectories were developed in line with a 0.5% and 2.5% annual growth in population and UK gross domestic product respectively [3.1].

[4] Available at www.2050-calculator-tool.decc.gov.uk/

The '2050 Pathways Calculator' does not look for an optimal or preferred route. The tool has been produced to simply demonstrate the scale of the changes that will be required to the UK energy system, and the choices and trade-offs which will materialise. The DECC calculator therefore studies the limits of the UK energy system, considering what might be practically and physically deliverable in each sector over 40 years, and does not include cost optimisation [3.1]. Hence the least cost cross-sector trajectory to meet the 2050 emissions target is not identified and therefore costs related to network infrastructure or supply are not adequately assessed – for assessing the reinforcement requirement to the GB transmission network, an overall cost was attributed, without application of a power flow and without geographical consideration, using an assumed £million/GW coefficient on an estimation of the required network carrying capacity.

Other criteria such as the interactions between sectors, public acceptability, land use impacts, environmental impacts, deliverability and technological risk, international dependency, business strategy, and fiscal, competitive and socioeconomic and welfare impacts (both positive and negative) could be key in determining the most desirable and deliverable path to 2050, and these conditions have also been excluded in the DECC calculator [3.1]. Further, the policy decisions which would be required to deliver the created future scenarios are excluded. However, it is likely that all sectors of society will need to be heavily involved to create a low carbon economy, and climate change needs to be tackled both centrally and through local, bottom up solutions.

The DECC calculator did not include a thorough technical feasibility study of the scenarios created. For instance, in relation to balancing supply and demand of energy in the electrical system, the tool did not fully model the annual requirement of the scenario, and merely assessed the ability of the system to meet increased electrical demand during a five-day period of light wind speeds and low temperatures [3.1]. However, the DECC calculator did provide an initial basis on which a consensus across society could be built through detailing to a wider audience the possibilities for a low carbon future, and the role which different parts of society could play in the required energy transition.

Many potential scenarios could be created using the tool and six illustrative scenarios (plus a high carbon reference case) were developed by DECC which all achieve the 80% 2050 emissions reduction target: emissions from energy supply/use, transport (including international aviation and shipping), agriculture, waste, industrial processes, CCS, land use and land use change and forestry were included in the assessment. The six scenarios developed minimised the need for an extreme level of change in any of the supply or demand sectors, whilst also aiming to avoid incompatible combinations of trajectories; such as very high levels of solar photovoltaic and solar thermal at a time where the roof space required may not be sufficient. The scenarios developed using the DECC calculator are as follows:

- **Pathway Alpha:** a balanced scenario across all energy supply and demand sectors, requiring physical and technical ambition. The pathway involves a resolute effort on energy demand reduction, developments in large-scale low carbon electrical generation (onshore and offshore wind, nuclear, and coal/gas with CCS), and in the utilisation of bioenergy (imports of bioenergy are predicted to rise and 10% of UK land is assumed to be used for co-firing in plant with CCS). A small reduction in overall energy demand is predicted by 2050, as a result of more energy-efficient lighting and appliances, increased insulation in homes and buildings, and the use of district heating schemes connected to large power stations (predicted to meet between 40-70% of domestic heat demand by 2050). However, electrical demand is predicted to double as a result of the increased electrification of industry, heating and transport – a significant penetration of electric and plug-in hybrid electric vehicles is predicted by 2050, covering 60% of the transport sector mileage (with fuel cell vehicles covering 20%). All the UK's electricity is predicted to come from low carbon sources by 2040. However, a significant annual rate of 1.2GW and 1.5GW in new nuclear plant and fossil fuel generation with CCS is assumed to be required beyond 2020 and 2030 respectively. To match energy supply with demand, according to the five-day assessment period, 2GW of fossil fuelled back-up generation was predicted to be required.

- **Pathway Beta:** a scenario which assumes that large-scale CCS technology cannot be used to generate low carbon electricity. No further CCS plants are built beyond the demonstration plants implemented before 2018. Thus, a significant increase, compared with the Alpha scenario, in utilising offshore wind and importing bioenergy (to be used in this case for liquid biofuels) by 2050 is predicted. Under this pathway an increased reduction in energy demand, via the replacement of all lights with light emitting diodes and using more efficient appliances, is predicted and a greater efficiency in aviation is assumed. The challenges of balancing grid supply and demand are greater for this scenario and 5GW of fossil-fuelled back-up generation was predicted to be required.

- **Pathway Gamma:** a scenario which assumes that no nuclear plant is built. Compared to the Alpha scenario, this assumption results in a significant increase in the utilisation of both onshore and offshore wind, distributed solar photovoltaic (equivalent to 5.4 square meters of panels per person by 2050) and bioenergy imports. As in the Beta pathway, energy demand is reduced in both the domestic and commercial sectors, more significantly than with the Alpha pathway, and efficiencies are witnessed in aviation. The challenges of balancing grid supply and demand are more substantial than with Beta and Alpha, and a much greater increase in storage, flexible demand, system interconnection, and fossil-fuelled back-up generation was predicted to be required by 2050.

- **Pathway Delta:** a scenario which considers the impact of only building a minimal amount of renewable generation capacity. Thus, a significant increase in nuclear generation (from 57TWh of electrical supply in 2007 to 633TWh in 2050) and imports of bioenergy was predicted in comparison to the Alpha pathway. Energy demand is also reduced significantly across more sectors, involving the increased use of insulation. As in Gamma and Beta, efficiencies are seen in aviation and demand reductions in lighting, cooking and appliances are predicted. Without intermittent renewable generation, no fossil-fuelled back-up generation was required in this case for 2050.

- **Pathway Epsilon:** a scenario which considers the impact of a limitation in the supplies of bioenergy (a similar level of imports to the Alpha pathway, but only 5% of UK land is assumed to be used for biomass co-firing). According to the DECC calculator, it is not possible to achieve an 80% emissions reduction by 2050 with no bioenergy available, and significant levels of solar thermal (resulting in approximately supplying 30% of hot water demand), compared to the Alpha pathway, are required to meet the emissions target with low levels of bioenergy. Extremely high levels of electrification in heating and transport were assumed in this scenario, with all vehicle transport being electrically fuelled by 2050, and all heating being electrically supplied.

The scenario requirements for demand reduction and the balancing of supply are similar to the Alpha pathway.

- **Pathway Zeta:** a scenario which considers the impact of little behavioural change in consumers and businesses. No effort is therefore made to improve insulation levels in housing, reduce demand or improve the efficiency of appliances, lighting and cooking. In the transport sector less people shift to cycling or using public transport, the freight sector undergoes little change and no efficiencies are made in aviation. Extremely high levels of electrification in heating, transport and industry are therefore required and the level of offshore wind generation is significantly increased in comparison to the Alpha pathway. Electricity imports and the required capacity of fossil-fuelled back-up generation (similar to the Beta pathway), to balance electrical supply and demand, are also significantly higher; however, the required utilisation of bioenergy by 2050 is the same.

- **High Carbon Reference Case:** a base case scenario which assumes little or no attempt at decarbonising the UK energy system, with no installation of new technologies. This pathway does not meet the 80% emissions reduction target in 2050 and due to a lack of a diverse energy supply, is predicted not to be supply secure against system shocks. It was predicted for this scenario that total emissions would only fall by around 16% by 2050, from 1990 levels; a result of the emissions reductions already achieved between 1990 and 2010.

Although the DECC calculator only provided a high-level analysis of future transitions to the UK energy system, it could be used to explore the scale, rate of change, and some of the key decisions required to achieve a UK low carbon energy system. The six scenarios created above illustrate this and several similarities, uncertainties, and trade-offs presented by the scenarios have been defined and outlined in the DECC 2050 Pathways Analysis report [3.1]. These relate to the required levels of demand reduction, electrification (of heating, transport and industry), low-carbon generation, sustainable bioenergy and electrical grid balancing. Concerns related to changes in international dynamics, the availability of bioenergy, and the environmental impact and technological uncertainty of low carbon generation are also raised by the analysis. However, a more detailed technical feasibility study and economic assessment would be needed to evaluate scenarios created by the DECC calculator, to better quantify the concerns raised by the initial DECC analysis, and to aid in defining a precise electrical generation mix to achieve the 80% emissions reduction target.

As discussed in the DECC 2050 Pathways Analysis report [3.1], the shape of the future UK electrical transmission and distribution networks, as well as the gas distribution network, is a major uncertainty and it is not clear what the optimal energy infrastructure should be. A likely decline in the use of gas generation, which is not offset by the potential increased use of biogas, will result in the diminished use of the gas distribution network. However, a highly electrical future is likely and this will result in the increased use of the electrical network. The DECC calculator does not consider the effect of a scenarios impact on the UK electrical network and therefore a posterior evaluation of scenarios created by the DECC calculator (including the illustrative pathways) is required to better understand this uncertainty. This thesis advises that the flexible, systematic framework proposed for scenario related transmission reinforcement planning, would be a sufficient approach to carry out this evaluation for the six illustrative scenarios created by DECC.

## 3.3. Long-Term Electricity Network Scenarios (LENS) 2050

The long-term electricity network scenarios (LENS) project prepared for Ofgem, sets out five scenarios for the GB electricity network in 2050. The scenarios were created following an iterative process of stakeholder consultation, workshops and peer review. This project was designed to encourage discussion between industry participants, the government and Ofgem on long term network issues, the focus of which was on the GB electricity networks (both transmission and distribution). Before the 2008 LENS project report [3.2], other scenario studies typically looked at the wider GB or UK energy and electricity sector, with a medium-term focus on networks and a lesser consideration of broader energy system aspects, including European and global influences [3.2].

The scenarios generated provided insights into how the 80% emissions reduction target for 2050, amongst other government targets, could be met in the electricity sector and across the energy system; however, they were not specifically designed to meet them. Similarly to *DECC 2050*, the focus was more on defining the underlying driving forces required to achieve significant changes in the UK energy system. The five scenarios were developed by considering the interactions between the main themes of environmental concern (moderate or acute) on a UK and global basis – relating to the level at which the environmental situation affects the decision making of individuals, communities, private companies, public institutions and the government. They were also developed to consider consumer participation (passive or active) in the energy market and institutional governance (market led or government led) to address societal concerns or further overarching policy goals [3.2]. The scenario narratives were produced and continually refined during the development process, however, a technical feasibility and plausibility study of the scenarios was not included until after the final version of the scenarios had been created, and therefore was not used to improve the robustness of the associated qualitative and quantitative assumptions. Further, the modelling work employed for this study was not made (or intended) to precisely match the scenario storylines [3.2]. The scenarios developed in the LENS 2050 project are summarised below:

- **Big Transmission and Distribution (Big T&D)**: this scenario involves transmission system operators (TSOs) at the centre of the GB networks activity. This is a business as usual scenario where societal environmental concern continues to be at a high level but consumers remain relatively unreceptive towards their electricity supply, mainly due to a continued level of high supply security. Markets are therefore assumed to continue to be best placed to service the energy requirements of the nation. Fossil fuel generation continues to from a large proportion of the generation mix and a significant amount of large scale renewable and low carbon generation capacity (mainly from onshore and offshore wind) is developed in line with planned developments and trends according to the Crown Estate licensing rounds. The electrical transmission network is required to expand under this scenario and increased interconnection to external systems is assumed to access additional economic sources of energy, and provide increased network security and operational services. The electrical distribution network is also assumed to expand in line with increased energy demand; however, active network management (ANM) schemes are not needed.

- **Energy Service Companies (ESCO)**: in this case ESCOs are at the centre of network developments. Again, consumers remain relatively passive towards their energy supply, however environmental concern has increased. Market solutions continue to be used to drive change, and a vibrant "energy services" market is developed to carry out strong interventions to address environmental issues. The electrical distribution network is developed to accommodate the connection of increased levels of local generation, and increasingly utilise ANM schemes to maximise local supply. The GB transmission network is also still expanded to facilitate the connection of large scale renewable generation.

- **Distribution System Operators (DSO)**: DSOs take over the central role in managing the electricity system for this scenario. Strong governmental intervention occurs in the energy sector as a result of increased energy prices, concerns for energy security and the increased likelihood of failure in the delivery of intermediate climate change policies and emissions reduction targets. Consumers are active towards their electricity supplies due to an increased level of environmental concern and a desire to reduce electricity bills. The UK distribution network undergoes significant changes and expands under this scenario to accommodate high levels of different distributed generation technologies. Further, ANM schemes are widely utilised at both transmission and distribution level, greatly increasing the demand control capability of the system. The transmission network continues to be used for the bulk transmission of power, however, the power flows are more variable and of a lower magnitude across the year.

- **Microgrids (MG)**: this scenario involves consumers at the centre of network developments in which they are very active towards energy provision, leading to an uptake in economic energy services with a reduced environmental impact. Through active consumers and widespread liberal markets, a very large penetration of local generating units and ANM schemes (down to customer supplies) result on the distribution network, and the role of the transmission network and centralised large-scale generation, to meet demand, is reduced; though operational support is still provided. This scenario requires a notable use of domestic demand side management to meet the availability of local variable supply.

- **Multi-Purpose Networks (M-PN)**: in this case all network companies are involved in required changes to policy and market arrangements. Hence, TSOs and distribution companies both have a significant role in the transformation of the electricity network. Societal uncertainty towards the environment, fossil fuel prices and energy security leads to a fluctuating level of concern and activity from consumers and the Government. Market led and Government led environmental solutions are also designed to alleviate short term matters related to supply security and economic concerns. Hence a consistent long term strategic approach is not adopted and electricity networks are therefore only reinforced in specific areas, creating regional variations in network design and capability. This leads to a high risk of stranded network assets and network congestion across the UK system.

To obtain quantitative detail for the scenario narratives, a UK version of the MARKAL (Market Allocation) model was used. The MARKAL model is a multi-time period linear optimisation, economic energy system and environmental model, which has been used to inform energy policy throughout several countries. The UK MARKAL model provides a bottom-up technology-rich depiction of the entire UK energy system and includes as part of the MARKAL model design, imports, fuel processing and supply of domestic generation, infrastructure representation (gas and liquid hydrogen pipelines), fuel conversion to secondary energy carriers (i.e. electricity, heat and/or hydrogen), end use technologies (in the residential, commercial, industrial, transport and agricultural sectors), and sub-sectoral energy service demands [3.3]. The main objective is to minimise the overall discounted energy system cost to meet demand, considering the evolving costs, characteristics and constraints of the aforementioned considerations [3.3].

The standard UK MARKAL model is an aggregated model which does not consider the size of generating units for each electrical plant type or the spatial disaggregation of electrical resources, infrastructures and demand [3.4]. Further to this, only the gas and hydrogen infrastructure is considered, through the inclusion of pipelines and storage facilities; overhead lines and underground cables associated with the electrical infrastructure are therefore excluded. Temporal representation is also simplified, with annual space heating and hot water demand being modelled against six time slices; two diurnal (day and night) across three seasons (winter, summer and intermediate). Further the UK MARKAL model, through maximising the utilisation of each plant type (after taking into account the time required for annual maintenance), overestimates the annual output able to be achieved from each plant type and therefore the associated installed capacity is lower than would be expected to meet scenario demand [3.4]. The standard model also assumes inelastic demand, where customers do not alter their electrical demand in response to price changes in the energy market.

Alternative versions of the standard UK MARKAL model exist to improve the performance. A macro version enables the inclusion of producers (supplying other services), consumers and a generic capital market, in addition to users of the energy market (as covered in MARKAL), to calculate the overall impact of decarbonisation on the growth of UK gross domestic product [3.4]. A stochastic version exists, which allows for uncertainties in market foresight to be included, and a temporal version has been designed, which allows for twenty annual time periods using five diurnal periods (morning, daytime, evening peak, late evening and night; for storage technologies) across four seasons [3.4]. The UK MARKAL model has also been linked to a Geographical Information Systems (GIS) based model, to improve the spatial disaggregation of hydrogen demand, supply and infrastructure. Here, 12 major demand centres and 6 supply points were defined throughout the UK and 3 infrastructure options were considered; liquid hydrogen delivery by tanker, large-scale pipeline networks, and small scale on-site production [3.4].

A two-region version has also been designed to improve spatial disaggregation from the standard model. This version separates Scotland from the rest of the UK to examine the possibility of devolved energy policy in Scotland [3.5]. Consequently, an initial design iteration of the flexible, systematic framework proposed in this thesis for transmission reinforcement planning was used to assess three energy scenarios[5] for 2020 generated by the two region UK MARKAL model [3.6]. This enabled the inclusion of a highly disaggregated spatial evaluation of the scenarios impact on the GB electrical transmission network, and separate economic conclusions to be formed on the network impact in Scotland and the rest of the UK.

To model the DSO scenario and the MG scenario in particular, the LENS 2050 project utilises a version of the standard UK MARKAL model that caters for flexible demand. The MARKAL Elastic Demand (MED) model defines demand functions which determine how each energy service demand varies as a result of the market price of that energy service. These demand functions can be defined for residential demand sectors (e.g. space and water heating), services

[5] The scenarios studied consisted of a scenario under which the UK meets 2020 obligations under the Renewable Energy Directive (15% of final energy, including heat, power and transport, must be obtained from renewable sources), a scenario which meets Renewable Energy Directive targets and also meets a target in Scotland for producing renewable electricity equivalent to 100% of electricity consumption. Further, a low carbon scenario which achieves emissions reductions beyond 2020 targets set out in the Climate Change Act (2008) and Climate Change (Scotland) Act 2009 respectively for the UK and Scotland (corresponding to a 34% and 42% emissions reduction by 2020) [3.7].

related to cooking, lighting and refrigeration, industry and agricultural sectors (e.g. iron and steel production), and transport [3.4]. However, the elasticities assumed are long-run, to match the 5-year time period assessment of the MED model [3.4]. The time horizon of the MED model, like the standard UK MARKAL model, is 50 years and so hour by hour system balancing of supply and demand is greatly simplified. For this reason, as well as the limitations associated with the standard model mentioned above, the MED model cannot output directly equivalent quantitative versions of the LENS project scenario narratives. Table 3.1 details the key quantitative details of the scenarios, as produced by the MED model.

The LENS project provided a strong starting point for further study among academic stakeholders. The *Transition Pathways to a Low Carbon Economy* project, as described later in this chapter, used the LENS scenarios as a basis for the associated research [3.2]. Key findings related to the scale of change required to the GB transmission and distribution networks; engaging GB network stakeholders to develop strategies and plans for the future GB network. Following the LENS project in 2008, Ofgem stated that "it is not clear whether we will need much larger networks or much smaller networks in the future" [3.8]. Electricity North West Ltd and Centrica – distribution network owners and operators in the UK – raised concerns as to the future direction of the overall GB network. Electricity North West Ltd stated that "it is now necessary to move the whole weight of the industry behind a clearly stated, preferred option if we as a nation are serious about achieving targets" [3.8]. Centrica identified that "there is a need to recognise the overall direction – is it towards a 2050 'big' transmission, 'small' distribution network scenario or vice versa" [3.8]. Conversely, Dr Michael Pollitt said that keeping technological options open has benefits, noting that "we just don't know at this stage what the best network configuration is for 2020 or 2050, not least because of price, policy and technological uncertainty" [3.8].

The evolution of the electricity generation mix to 2020 in the UK can be confidently predicted, however there is still much less certainty as to what a completely decarbonised energy system looks like in the future. Following the LENS project, it was clear that the Government's vision for the future GB electrical network must consider a range of possible scenarios for the evolution of the energy mix, ensuring that Great Britain is not forced down a particular path at too early a stage, particularly if the path proves to be sub-optimal economically and technologically, through the misuse of more efficient emerging technologies.

**Table 3-1 Key MED model outputs for LENS 2050 scenarios (source [3.2])**

| | 2000 | 2050 | | | | |
|---|---|---|---|---|---|---|
| | | Big T&D | ESCO | DSO | MG | M-PN |
| **Total Energy Demand (PJ)**[1] | **6,189** | **6,468** | **5,807** | **4,910** | **4,558** | **5,785** |
| Transport | 1,855 | 2,142 | 1,542 | 1,292 | 1,255 | 1,538 |
| Residential | 1,961 | 1,920 | 1,921 | 1,625 | 1,431 | 1,920 |
| Other (Industry, Services & Agriculture) | 2,374 | 2,407 | 2,345 | 1,993 | 1,872 | 2,327 |
| **Total Electricity Demand (PJ)**[2] | **1,176** | **1,522** | **1,623** | **1,243** | **1,044** | **1,662** |
| Transport | 20 | 85 | 330 | 126 | 263 | 343 |
| Residential | 403 | 587 | 473 | 378 | 195 | 531 |
| Other[3] | 754 | 851 | 819 | 739 | 585 | 788 |
| **Total Electricity Generation Capacity** | **84** | **102** | **121** | **105** | **113** | **114** |
| Large Scale Generation: | | | | | | |
| Fossil Fuel (Including CCS) | 59 | 68 | 55 | 27 | 9 | 49 |
| Nuclear | 12 | 0 | 13 | 19 | 27 | 18 |
| Renewables | 4 | 20 | 24 | 22 | 16 | 24 |
| Interconnections | 2 | 11 | 10 | 10 | 12 | 11 |
| CHP | 4 | 2 | 1 | 0 | 0 | 2 |
| Storage | 3 | 1 | 1 | 1 | 1 | 1 |
| **Sub-total** | **84** | **102** | **104** | **81** | **66** | **105** |
| Small Scale Generation: | | | | | | |
| Micro CHP | 0 | 0 | 0 | 0 | 24 | 0 |
| Micro Generation | 0 | 0 | 17 | 24 | 23 | 9 |
| **Sub-total** | **0** | **0** | **17** | **24** | **48** | **9** |
| **Total Electricity Generation Output (PJ)** | **1,288** | **1,652** | **1,874** | **1,501** | **1,462** | **1,860** |
| Large Scale Generation: | | | | | | |
| Fossil Fuel (Including CCS) | 854 | 1,173 | 1,016 | 457 | 100 | 913 |
| Nuclear | 282 | 0 | 334 | 502 | 713 | 482 |
| Renewables | 46 | 271 | 300 | 279 | 209 | 279 |
| Interconnections | 52 | 182 | 103 | 103 | 103 | 103 |
| CHP | 45 | 27 | 8 | 7 | 7 | 27 |
| Storage | 10 | 0 | 0 | 0 | 0 | 0 |
| **Sub-total** | **1,288** | **1,652** | **1,761** | **1,348** | **1,131** | **1,804** |
| Small Scale Generation: | | | | | | |
| Micro CHP | 0 | 0 | 0 | 0 | 142 | 0 |
| Micro Generation | 0 | 0 | 113 | 153 | 189 | 56 |
| **Sub-total** | **0** | **0** | **113** | **153** | **331** | **56** |
| **$CO_2$ Emission Reduction from 2000 (Mt)** | | | | | | |
| Energy System Reduction | 0% | 30% | 47% | 61% | 71% | 45% |
| Electricity Sector Reduction | 0% | 67% | 88% | 95% | 99% | 79% |

[1] 1PJ = 0.278TWh
[2] Sectoral demand figures do not include the proportion of demand met by small scale electricity generation.
[3] Industry, Services, Agriculture, Hydrogen and Upstreams.

## 3.4. The UK Energy Research Centre's Energy 2050 Project

The UK Energy Research Centre (UKERC) is a hub of UK energy research, which utilises interdisciplinary, whole-systems research to inform UK policy development and research strategy. Phase one of UKERC facilitated the development of the UK MARKAL model. In 2007-2008, near the end of phase one, the UK MARKAL model was used to evaluate different projections of the UK energy system in the Energy 2050 programme, as published by Skea *et al.* [3.9]. Following this study, the UK MARKAL model has since been used to analyse scenarios in the LENS project (as previously described), and for the Committee on Climate Change [3.10] and DECC [3.11], to aid the creation of a fourth Carbon Budget. Further, the UK MARKAL model was again used for UKERC in phase two of the Energy 2050 programme [3.12].

A number of pathways to a low carbon economy were produced in phase one, which consisted of varying levels in decarbonisation targets, resilience, lifestyle change, technology acceleration and global uncertainties. Phase two of the UKERC Energy 2050 project created new scenarios to incorporate the latest energy policies. This phase also enabled an investigation into the future impact of lower gas prices and into measures for increasing the resilience of the energy system, in this case through targeting diversity in the evolving energy mix to 2050.

Phase one involved the use of the MED model, which as previously described, enabled the inclusion of flexible demand, but still lacked spatial and temporal disaggregation of energy network infrastructure and supply-demand grid balancing requirements respectively. The MED model did however also include, amongst other improvements to the standard UK MARKAL model, updated fossil resource costs, expanded categorisation of UK CCS and wind resources, new hydrogen infrastructures, improved treatment of electricity intermittency, updated electricity technology and energy service demand assumptions, buildings technology updates (including micro-CHP and heat pumps), transport technology updates (including plug-in hybrid electric vehicles) and all UK policy measures throughout 2007 (including updated EU Emissions Trading Scheme pricing) [3.13]. The latter improvement enabled more up-to-date policy interventions to be systematically introduced depending on the scenario.

To analyse the resilience of the UK energy system to withstand external shocks (particularly in the gas system) and examine how such measures interact with those designed to reduce $CO_2$ emissions, the MED model was used in tandem with two other linear optimisation models known as the Wien Automatic System Planning (WASP) model [3.14], and the Combined Gas and Electricity Network (CGEN) model [3.15]. The WASP model is an electricity generation expansion planning model used to explore, in more detail than the MED model, the levels of investment required in generation assets to maintain a reliable supply. It is a cost minimisation model, which used electricity demand assumptions from the MED model [3.14]. The CGEN model is a geographically explicit model used to assess where electricity generation capacity should be located and the level of gas and electricity infrastructure (electrical lines, gas pipelines, gas storage, and gas import terminals) required to be constructed. This is also a cost minimisation model which used outputs from both the MED and WASP models [3.14].

The timely and optimal deployment of adequate electrical generating capacity, to maintain supply security whilst meeting policy goals relating to energy supply, the environment, and energy pricing, is a conflicting multi-objective problem. The WASP model simplifies this problem to a single-objective and locates an optimal generation expansion plan based on the minimisation of discounted total costs, whilst adhering to system reliability constraints associated with reserve margin, loss-of-load expectation, and un-served energy [3.14]. The cost objective function includes capital investment costs (assumed to change over time), the salvage value of investment costs, fuel costs, fuel inventory costs, operation and maintenance costs and the cost of energy not served [3.14].

The model utilises a probabilistic simulation to carry out the evaluation and provides options for introducing constraints on environmental emissions, fuel usage and energy generation; enabling the availability of some fuels, and some plant types to be restricted. The inclusion of the WASP model in the UKERC 2050 project improved the temporal assessment of supply-demand grid balancing. The WASP model considered the variation of electrical demand out to 2050 by utilising annual forecast peak demand values obtained from the MED model, and using transformed load duration curves (LDCs), previously corresponding to one hour, to represent 12 equally sub-divided time periods of each year [3.14].

The CGEN model is also a single-objective cost minimisation model, which aims to minimise total discounted costs related to the combined operation and expansion of the GB gas and electricity networks, ensuring demand defined from the MED model is met to 2050. The interaction between both networks is through mutually connected gas turbine generators. For the gas network, the gas turbine is a load whose value depends on the power flow in the electrical transmission network. In the electrical network, the gas turbine is a source of generation. The GB gas network is explicitly modelled in detail and includes gas storage and compressor station facilities. The gas flow rates in each pipe, determined by the pressure difference between upstream and downstream nodes, and the linepack of each pipe – defined as the volume of gas stored in the pipe – is assessed in the model [3.15]. However, the GB electrical network is greatly simplified to a 16 node (i.e. bus), 15-line network model. Further, a DC power flow estimation of the system is used which includes an estimation of active power flows but excludes issues related to voltage magnitude, reactive power management and transmission losses [3.16].

Although the CGEN model does provide an improvement in the consideration and geographical disaggregation of the GB energy infrastructure from the modelling work of DECC 2050 and LENS 2050, the simplified electrical network hinders the ability to define constraints and determine a realistic investment cost for the scenario. Further, the single-objective optimisation carried out in the model does not therefore consider the complexity and the conflicting nature of the transmission reinforcement planning problem.

The first phase of the UKERC Energy 2050 project produced 8 scenarios in total, including the reference base case. The first set of scenarios (CFH, CLC, CAM, CSAM – as defined in Table 3-2) focused on achieving a UK reduction in $CO_2$ emission levels, from 1990, of between 40% and 90%; with intermediate targets in 2020 which ranged from 15% to a 32% reduction. These scenarios investigated increasingly stringent targets as well as the associated price-induced behavioural change and policy measures to meet these targets. The second set of scenarios (CEA, CCP, CCSP – as defined in Table 3-2) undertook a sensitivity analysis around the 80% $CO_2$ emissions reduction target, and these scenarios were used to investigate trade-offs and pathway dependencies. Table 3-2 details the carbon reduction pathways produced in phase one. Information on the sectoral split of $CO_2$ emissions (across, among other areas, transport, electricity, residential and industry), the energy demand by fuel type in 2035 and 2050, the electrical generation mix in 2035 and 2050, trends in the marginal cost of $CO_2$, transport sector energy demands and other areas of interest, for each phase one scenario, is detailed in Anandarajah *et al.* [3.13] and Usher *et al.* [3.12].

Phase 2 of the UKERC Energy 2050 project incorporated policy updates for scenario-related systematic inclusion (including, for example, Renewable Energy Directive targets and the Renewable Transport Fuel Obligation [3.12]), and MED model updates that had taken place since phase one in 2008. A new set of UKERC Energy 2050 scenarios was developed which also enabled updated technology assumptions in the MED model to be considered. Additional scenarios variants were also produced to test the impact of alternative trends in gas pricing,

**Table 3-2 Carbon Reduction Pathways for UKERC 2050 Phase One (source [3.12])**

| Scenario | Name | Emissions Reduction Target | Cumulative Emissions $GTCO_2$ | 2050 Emissions $MTCO_2$ |
|---|---|---|---|---|
| B | Base Case | - | 30.03 | 583 |
| CFH | Faint-heart | 15% by 2020<br>40% by 2050 | 25.67 | 355 |
| CLC | Low Carbon Reference | 26% by 2020<br>60% by 2050 | 22.46 | 237 |
| CAM | Ambition | 26% by 2020<br>80% by 2050 | 20.39 | 118 |
| CSAM | Super Ambition | 32% by 2020<br>90% by 2050 | 17.98 | 59 |
| CEA | Early Action | 32% by 2020<br>80% by 2050 | 19.24 | 118 |
| CCP | Least Cost Path | 80% post 2050 | 19.24 | 67 |
| CCSP | Socially Optimal Least Cost Path | 80% post 2050 | 19.24 | 179 |

UK $CO_2$ emissions in 1990 were estimated to be 590 $MTCO_2$.

and explicit resilience measures. However, only the updated MED model was utilised and therefore no quantitative or spatial assessment on the impact of the phase 2 scenarios on the GB gas and electrical transmission network was included in the analysis.

The UKERC Energy 2050 project (phase one and two) highlighted the fundamental changes required in every part of the UK energy system to achieve large-scale decarbonisation. The energy efficiency of all buildings, as well as the use of heat pumps, bio-energy and district heating schemes, was highlighted as a key factor in reducing demand on the electrical network. The adaption of the existing gas infrastructure to accept different fuels such as bio-methane and hydrogen was defined as a potential evolution, to enable the increased adoption of CHP for domestic heating and hydrogen fuel cell electric vehicles. Further, the increase in electrical peak demand on the GB distribution and transmission network from the prevalent use of battery powered electric vehicles, unless widespread active network management is employed, was raised as a concern.

Concerning energy supply, it was defined that a maximum carbon intensity target of $100gCO_2/kWh$ for UK electricity in 2030 should be included in the 2012 Energy Bill, to increase the prospects of an emissions reduction of at least 80% (from the year 2000) being achieved [3.12]. CCS was highlighted as a key technology, particularly as the widespread use of gas generation without CCS after 2030, will not be compatible with achieving the UK's 80% emissions reduction target – significantly constrained use of natural gas will also reduce the resilience of the UK energy system. The electrical, residential and transport sectors were defined as being the largest carbon emitters, where the decarbonisation of the electricity sector by around 2030, and the near decarbonisation of buildings and transport by 2040, were defined as a requirement to meet the 80% reduction target.

The Electricity Market Reform, to be implemented through the 2012 Energy Bill, was subsequently recommended by the project team to incentivise either, or both, the large-scale deployment of new nuclear power or an increase in the rate of deployment of new renewable generation [3.12]. Phase one and two of the UKERC Energy 2050 project therefore made significant inroads into altering UK governmental energy policy.

## 3.5. *Transition Pathways to a Low Carbon Economy*

The *Transition Pathways to a Low Carbon Economy* consortium was established in 2008 and includes research teams at a wide range of Universities. For the first phase of the project, the overall aim was to select, develop and analyse a set of potential transition pathways for the UK energy system to a low carbon future. This involved the integration of technical and economic feasibility studies and the assessment of the social and environmental potential and suitability of the created pathways. Historically-informed and forward-looking analysis of energy system transitions was included, combining quantitative and qualitative research methods. The flexible, systematic framework proposed in this thesis for scenario related transmission reinforcement planning is part of phase one of the 'Transition Pathways' consortium.

Phase two of the project; *Realising Transition Pathways*, was established in 2012 with the aim to extend and enhance the work carried out in phase one, and explore, with a focus on electricity (including the electrical provision of heat and transport), what needs to be done to achieve a transition which provides the delivery of a low carbon, secure and affordable energy supply.

### 3.5.1. Scenario Creation

The scenarios created in the 'Transition Pathways' consortium analyse the socio-technical transitions required for technologies, institutions, business strategies and user practices, to create a low carbon system of energy supply and energy service provision. Governance challenges are raised in relation to both the engagement of different actors and to the incentives and barriers they face [3.17]. The transitions generated included the wider impacts and benefits to society, and addressed the interactions between societal and technological factors, to deal with wider governance challenges often excluded in scenario creation [3.18].

An analytical framework based on the interactions between three levels; *technological niches*, *socio-technical regimes*, and *landscapes*, was used to combine a technical, social and historical analysis of, and insights into, past and current transitions [3.18]. The *landscape* represented the political, social and cultural values and institutions of society; the *socio-technical regime* represented the current routines or practices that actors and institutions used to create/reinforce a technological system; and *niches* characterised spaces insulated (at least partially) from 'normal' market selection to allow for technological and social learning. This approach was used to analyse the historical dynamics of transitions and thus define a large range of factors on which transitions (past, present and future) can be influenced and specified; depicted in Figure 3-1. The approach aimed to identify how pathways could be shaped by a range of actor groups, including policymakers, current/new entrant market firms, consumers and civil society actors [3.18]. Further, potential branching points along the pathways, where cumulative or sudden pressures cause actors to respond and make choices which affects the pathways trajectory, could be analysed and identified.

To explore relationships between actors, an 'action space' approach was developed to analyse governance interactions between *government*, *market* and *civil society* actors [3.18]. The *government* actor related to the dominant, direct, national co-ordination of energy systems to deliver energy policy goals. The *market* actor related to the market led management of energy systems within a high-level policy framework. The *civil society* actor related to citizens taking a leading role in the decisions on energy system operation.

The action space was a visual representation of the relative influence of the associated actor groups, which could change over time in the course of a pathway. Essentially, the dominant actor defined the dominant form of governance in that periods 'action space'. This would

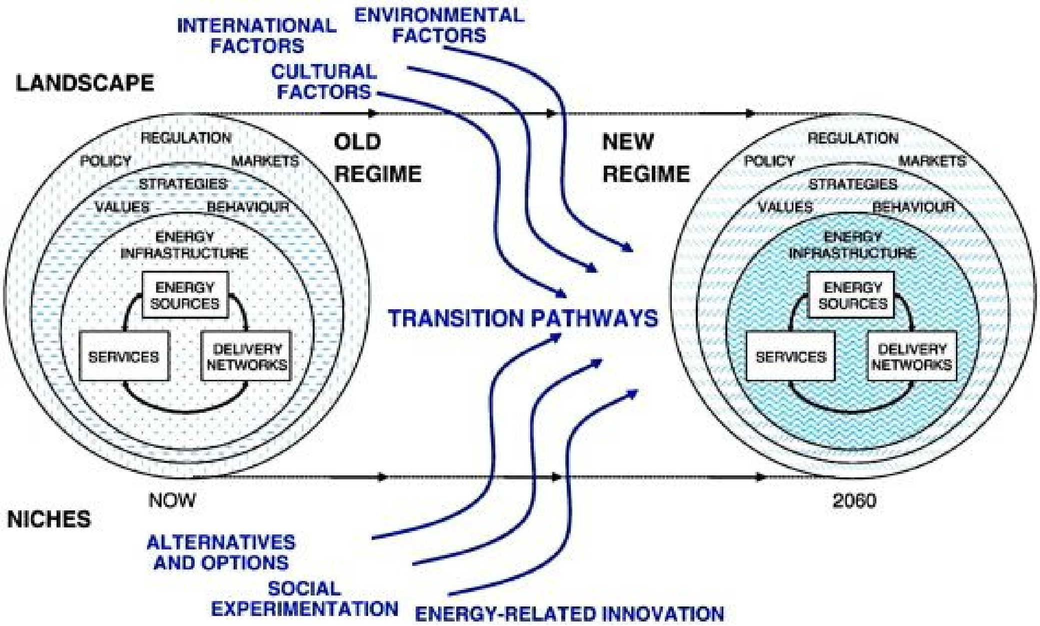


**Figure 3-1 Influential factors in transition pathways from a high-carbon to a low-carbon regime (source [3.1])**

influence the pathway and the associated branching points. As described by Foxon [3.18]; as a result of deregulation in the energy sector, *market* actors have dominated the UK in recent decades, following a period of dominance from *government* actors, resulting in nationalised energy industries. Further, the challenges of minimising cross-sector greenhouse gas emissions and ensuring energy supply security are currently resulting in a retreat to the dominance of the *governance* actor for UK energy systems, with niche examples of the *civil society* actor.

Three core transition pathways (or scenarios) to a low carbon electricity system were defined in phase one of the 'Transition Pathways' project, in which each one of the three competing actors dominated. Further, to simplify the analysis, the dominant actor was assumed to continue to dominate over time in the core pathways. As illustrated in Figure 3-2, a market-led pathway, 'Market Rules', a government-led pathway, 'Central Co-ordination', and a civil society-led pathway, 'Thousand Flowers', was therefore created. As the project focused on socio-technical transitions, narratives for the core transition pathways were required to be generated as well as quantitative information. The narratives were developed based on a critical review of UK and international low carbon energy scenarios, involving the evaluation of the associated typology and the approaches used in scenario building, carried out by Hughes *et al.* [3.19]. Further, stakeholder workshops related to policy, business and non-governmental

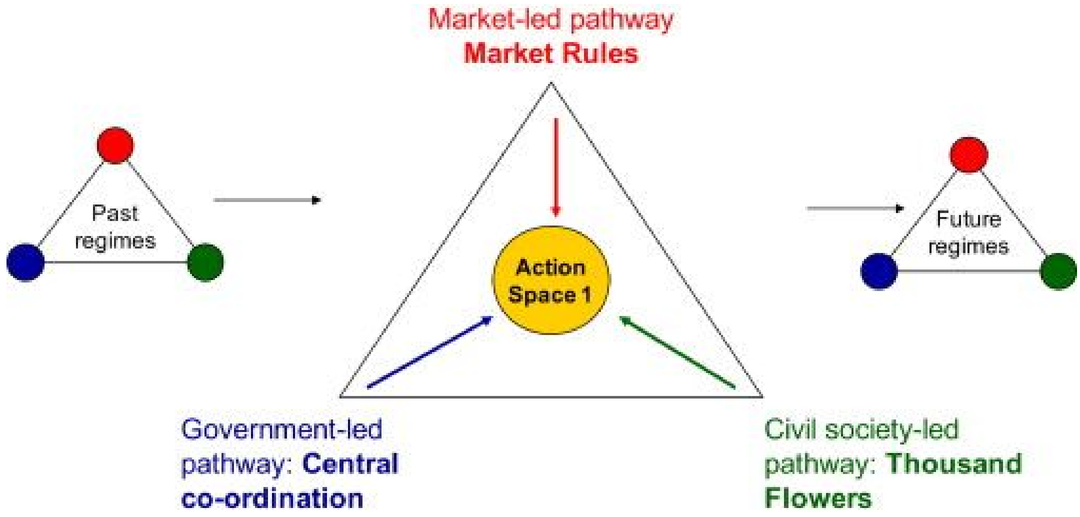


**Figure 3-2 Core transition pathways to a low carbon UK electricity system (source [3.2])**

organisations, and a set of interviews with energy system 'gatekeepers', were carried out to further inform the scenario stories.

An iterative process was carried out to generate the final narratives and quantitative information for the core scenarios. An initial quantification of the core pathways was undertaken which involved assessing variations in electrical demand and the required generation mix, according to the dominant actor of the pathway and the resulting choices set out in the narrative. This was merely carried out using expert knowledge and judgement garnered from theoretical and applied research experience within the project team. However, following this initial iteration, a more detailed analysis of the pathways was carried out and the narratives were in turn updated to reflect quantitative changes to the initial assessment. A bottom-up, sector based approach was used to project demand in domestic appliances, heating and transport, resulting in a prediction of the technology mixes and energy demands for heating, power and lighting, and an annual average electrical demand value for each pathway [3.20]. The evolution of the electricity generation mix required to supply annual demand was then reassessed and alterations to the mixes were made following the analysis of the effect of demand-side participation and the need for back-up generation to meet peak demand, using the Future Energy Scenario Assessment (FESA) tool [3.20].

The FESA tool alters a generation mix to match the calculated energy demand of a multitude of sectors on a yearly and hourly time step basis. An early version of the flexible, systematic framework proposed in this thesis – which excluded the SPEA2 optimisation and directly outputted initial reinforcement solutions – was combined with the FESA tool for phase one of the 'Transition Pathways' project. This combination enabled a more holistic analysis of electricity systems to be carried out in comparison to previous energy scenario projects, through the full assessment, on a temporal and spatial level, of a future energy scenarios ability to cope with varying demand/generation patterns, and a scenarios requirement for national transmission network reinforcement [3.21].

In comparison to *DECC 2050, LENS 2050* and UKERC's *Energy 2050* project, the use of the FESA tool to aid scenario creation was an improvement. The DECC tool, as mentioned previously, did not fully model the annual operation requirement of the energy scenario for matching supply and demand, and only assessed, and therefore created, a scenario against a five-day period involving light wind speeds and low temperatures. The MED model used in the *LENS 2050* project also lacked temporal disaggregation. For UKERC's *Energy 2050* project, the MED model was paired with WASP which improved the temporal assessment of scenario related supply-demand grid balancing requirements through utilising a number of load duration curves for each year (up to a maximum of 30 years), however only the electricity sector was examined, using electrical peak demand estimations from MED.

The FESA tool can evaluate, and therefore aid in creating a scenario which can match supply and demand of energy for all hours in the year, and for other sectors of the economy (apart from the electricity sector), such as transport, space and water heating, commerce, industry and agriculture. The FESA tool models the correlations and anti-correlations of variable supply and demand using Met Office weather data from around the UK which includes wind speeds, wave heights, solar irradiance and temperature. This data is used to predict the output from renewable generation (including wave and solar photovoltaic), solar water heating systems and the operation of CHP and electrical heating. FESA is also able to predict the UK production of coal, oil and gas, and therefore the net imports of these fuels. The tool includes the effect of energy storage from pumped hydro schemes and the potential outcome of using flexible demand from electric vehicles and domestic water and space heating/cooling [3.20].

The FESA tool aided in re-quantifying the scenarios developed and in turn helped to define the alterations required to the initial pathway narratives. The application of smart grids and the use of flexible domestic demand in the GB distribution network was a key driver in achieving the emission reductions in the core pathways. The social acceptability of flexible demand was therefore analysed through examining data from smart metering trials [3.22], and the results of this analysis was reflected in the updated pathway narratives. Also, in updating the pathways, further developments in UK energy policy and related published reports that occurred after the initial development and quantification of the pathways were considered. These developments included the publication of the *DECC 2050* scenarios, the recommendations for the fourth carbon budget period 2023 – 2027 [3.23], and the UK government's consultation and subsequent White Paper on electricity market reform [3.24]-[3.25].

As the *DECC 2050* scenarios focus only on the technical potential for different supply and demand mixes, it is argued by Foxon [3.18] that the associated analysis gives relatively little insight into how and by whom these changes would be achieved, and that the approach used in the 'Transition Pathways' project provides a greater insight into the challenges (both governance, behavioural and technical) of achieving emission reduction targets.

## 3.5.2. Generated Scenarios

Three core scenarios to achieve a UK low carbon electricity system were developed by the 'Transition Pathways' project; known as 'Market Rules', 'Central-Co-ordination' and 'Thousand Flowers'. Each scenario or 'pathway' aimed at reducing UK carbon emissions by 80% in 2050, from 1990 levels, in line with the UK government's greenhouse gas emissions target. Further, each scenario aimed to achieve energy security and affordability objectives throughout the transition to 2050. However, it was not assumed throughout the creation process that the scenarios generated did in fact achieve the low-carbon target.

**Market Rules** is a market led pathway which envisions the continued dominance of market arrangements for the governance of UK energy systems. Large energy firms therefore continue to be the dominant actors and the government continues to regulate and set frameworks. In this pathway, a highly electric future is envisaged and the large energy firms invest in large-scale power generation fuelled by nuclear, offshore wind, coal and gas (both with CCS); familiar schemes which the energy firms have adequate experience in. However, under the regulated framework of the government, this leads to a high carbon price as a result of stringent caps under the EU Emissions Trading Scheme[6]. The UK government continues to provide

[6] The EU Emissions Trading Scheme uses the 'cap and trade' principle and is the largest international system for trading greenhouse gas emission allowances.

support for renewable generation and the demonstration of CCS, to complement the incentive of a high carbon price.

As a result of investment into the above large-scale centralised generation schemes, a rapid decarbonisation of the electricity network results during the 2020s and current energy security standards are maintained. In the 2030s and 2040s, the increased use of electricity for heating (through air and ground-source heat pumps), transport (though hybrid and electric vehicles) and industrial processes leads to an increase of 50% in annual electrical demand by 2050 from 2010 levels, with a peak demand of around 91GW for the GB transmission network (around a 62% increase from current peak demand[7]). This results in an annual electrical supply requirement of 560TWh in 2050. Market Rules is a scenario which therefore focuses on the supply-side and little effort is made in the market to incentivise behavioural changes and reduce demand, beyond the purchase of more efficient appliances and the switching of heating from gas to electrical supply. Consumers initially are concerned about security of supply, and gradually accept the need for change to curtail climate change; however, they are unwilling to accept significant lifestyle changes. Risks involving the use of CCS, which could turn out to be both technologically and economically unfeasible on a large-scale, and constraints on the building of new nuclear plant, due to costs and/or higher levels of public opposition, exist if the scenario is implemented. The evolving electrical generation mix of Market Rules is detailed in Figure 3-3.

**Central Co-ordination** is a government led pathway which envisions greater direct administrative involvement in the governance of the UK energy system to achieve a low-carbon, secure and affordable energy service. Initially, a strategic energy agency is formed to issue tenders for particular types of low-carbon generation and push technological innovation to enable the UK to be a global leader in some of the associated technologies, and boost UK industry. In this pathway, this leads to an increased usage of marine generation (both wave and tidal power) as well as CCS and electric vehicles. Like Market Rules, large scale generation from nuclear, offshore wind and coal or gas with CCS is central to electrical supply for the scenario. These technologies are seen by the government as an opportunity to create jobs and potentially aid the UK economy through international exports. However, for this scenario a greater focus is placed on reducing demand, and the government, through the

[7] This calculation assumes a 56.1GW peak demand value (see footnote 1).

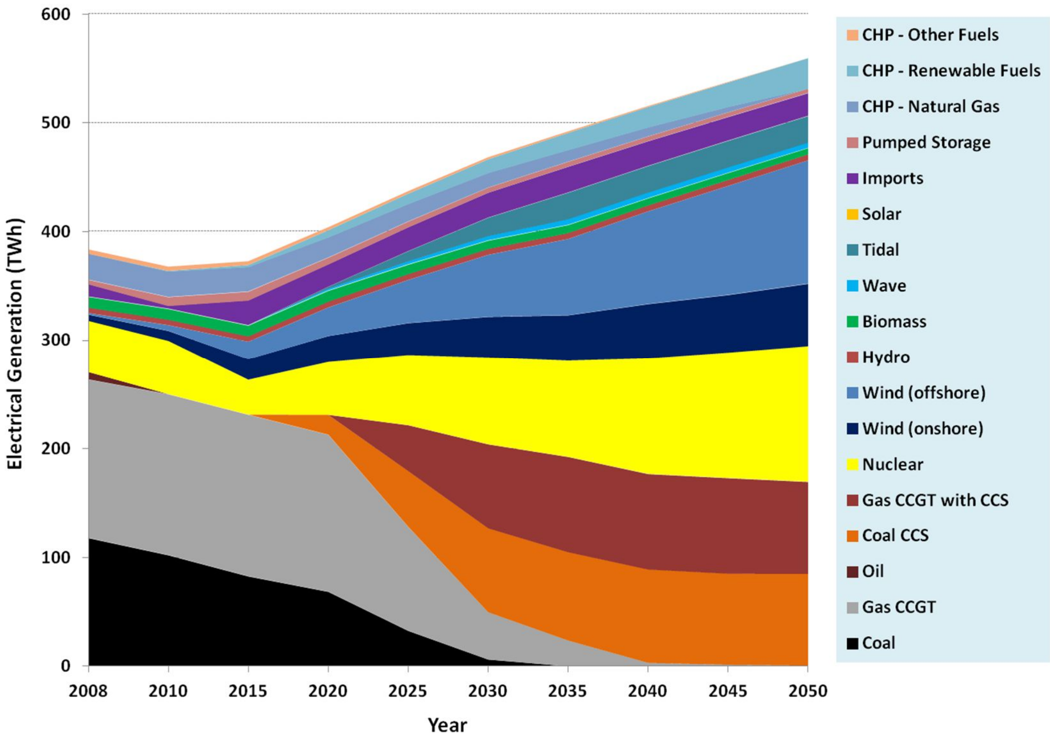


**Figure 3-3 Electricity generation mix of the Market Rules scenario (source [3.2])**

strategic energy agency, provides strong incentives to improve household energy efficiency. This is largely motivated by security of supply concerns.

Initially, non-intrusive efficiency measures on lifestyles and behavioural change are employed. Significant improvements in the energy efficiency of domestic appliances are predicted to occur early on in this scenario. Further, smart grids, using active network management, are incorporated across the GB distribution network from 2023, and smart metering is employed; enabling the initial management of 'smart' domestic appliances, to reduce peak demand. Statements on the electrical carbon content of their energy usage are also included on the customers' bills to help inform their decision making. However, as a result of a predicted continual increase in electrical demand during the 2030s and 2040s, for heating, transport and industrial processes, further energy efficiency improvements are required to be made (consumers demand appliances with a higher energy efficiency), and only a 20% increase in annual electrical demand by 2050 from 2010 levels results, with a peak demand to the GB transmission network of only 75GW in comparison to Market Rules. This results in an annual electrical supply requirement of 448TWh in 2050. Risks again exist in the application of CCS and public opposition could result from higher energy service costs resulting from high levels of low-carbon generation, if the scenario is implemented. The evolving electrical generation mix of Central Co-ordination is detailed in Figure 3-4.

The **Thousand Flowers** scenario is generally regarded as the most radical scenario produced by the 'Transition Pathways' project. It is a civil society led pathway which envisions the growing dominance of civil society in the governance of UK energy systems, and therefore a flourishing creation of diverse, local, bottom-up solutions for decentralised generation and energy conservation. Strong governmental obligations on improving energy efficiency lead to new partnerships between energy companies, local authorities and housing associations to improve the energy efficiency of new and existing building stock. Further, the government adopts a feed-in tariff model, initially for small-scale generation only, to encourage grid connection, and provides incentives for community involvement and local investment. Local district heating systems are therefore increasingly installed for this scenario.

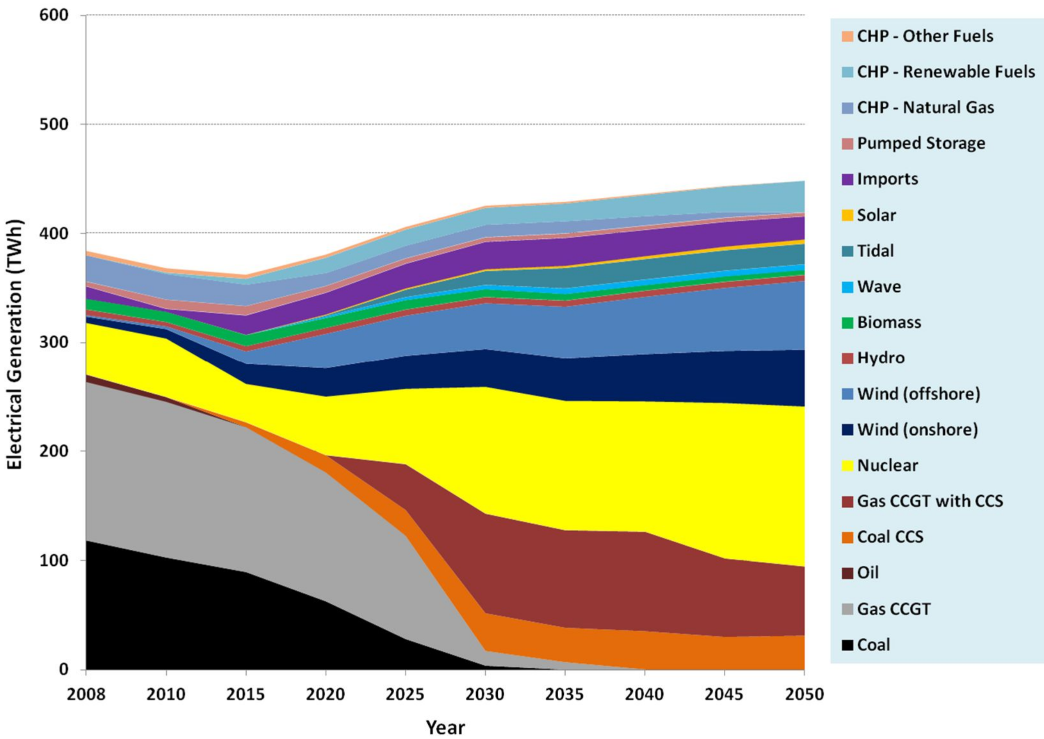


**Figure 3-4 Electricity generation mix of the Central Co-ordination scenario (source [3.2])**

A rapid growth of domestic and non-domestic distributed generation, led by new energy service companies and some of the large energy companies (adopting a new business model), is predicted to take place in the 2020s. Some large energy companies continue to invest in large-scale, centralised, coal CCS and nuclear generation. Others diversify to provide alternative revenue through increased community partnerships. For this scenario, both domestic and non-domestic distributed generation achieve high levels of adoption, meeting nearly half of total electrical demand by 2050. Further, due to greater energy efficiency improvements and the use of micro generation (mainly biogas CHP, solar PV and solar water heating), a decrease of 7.5% in electrical demand by 2050, relative to 2010 levels, is predicted, with a peak demand to the GB transmission network of only around 46GW. This leads to an electrical supply requirement of only 328TWh.

The distributed renewable generation is owned and operated by individuals, community groups, and small/large energy service companies. The traditional large integrated energy companies own and operate coal/gas with CCS and nuclear power plant. The risks of this scenario exist in the economic viability of installing or retrofitting a large penetration of

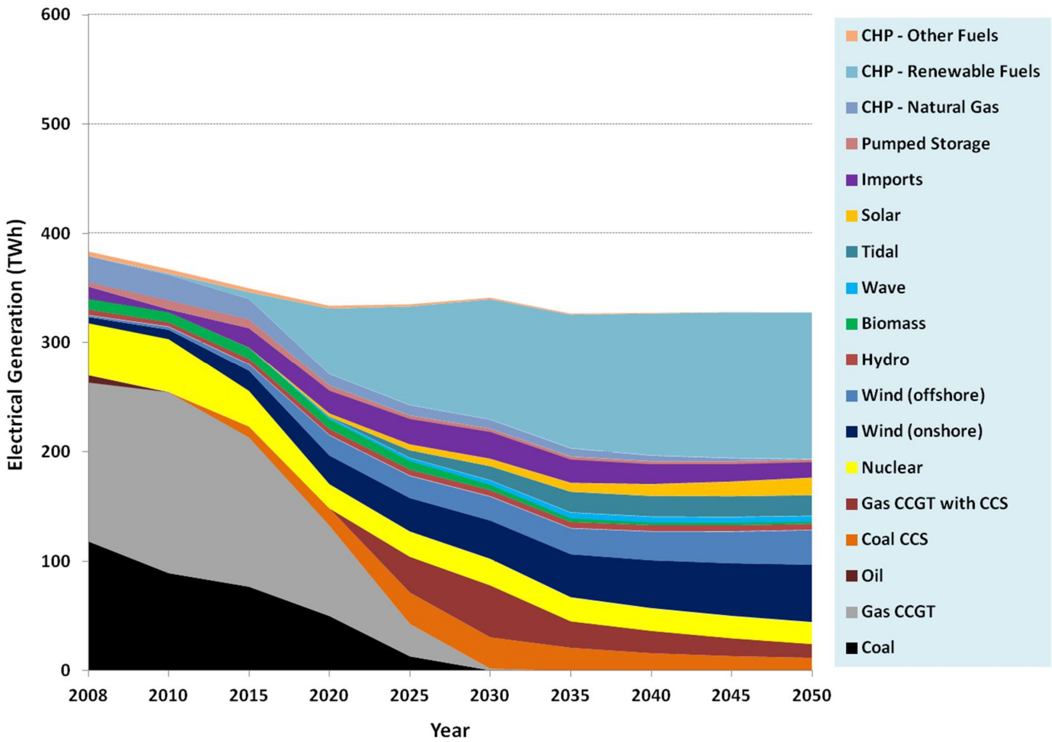


**Figure 3-5 Electricity generation mix of the Thousand Flowers scenario (source [3.2])**

distributed generation, and in the potential for a consumer backlash against local solutions when pressure to maintain supply security increases. Figure 3-5 details the evolving electrical generation mix of Thousand Flowers.

### 3.5.3. Scenario Evaluation

In phase one of the 'Transition Pathways' project a range of methods and models were developed to evaluate the core scenarios. A 'whole systems' sustainability appraisal of the pathways, including an assessment of their life-cycle carbon emissions, was carried out by Hammond *et al*. [3.26]. As the core pathways aimed, but were not assumed to achieve an 80% reduction in carbon emissions by 2050, this evaluation was critical in determining the success of the pathways. The 'whole systems' study highlighted the significance of including 'upstream emissions' as well as operational emissions, associated with electrical power plant in the scenario. In relation to the delivery of fuel the upstream emissions included the energy requirements for extraction, processing/refining, transport, fabrication, and in the case of coal and gas, methane leakage that occurs in coal mining activities and from natural gas pipelines [3.26].

Applying a 'whole systems' analysis – equating to the sum of the upstream and operational emissions across the lifetime of the plant – to low-carbon generation (such as CHP and plant with CCS) and to the pathways, was a novelty in comparison to previous UK studies. An important illustration of this analysis involved CCS, where it was found that the technology may only be able to deliver a 70% reduction in carbon emissions, across the lifetime of the technology (on a whole system basis), in contrast to previous assumptions of a 90% reduction, which only considered operational effects. From applying this analysis, it was determined that a decrease of 77% and 86% in carbon emissions from the UK electricity sector, from 1990 levels, could be achieved as a result of applying the Market Rules and Thousand Flowers scenarios respectively; Central Co-ordination resulted in a decrease between this range.

The FESA tool, as previously mentioned, was used to help create the quantitative information of the scenario and update the scenario narrative via an iterative process. The FESA tool evaluated the applicability of the scenarios through a detailed temporal assessment of supply and demand grid balancing; a requirement due to the reliance of the associated scenarios on variable renewable generation, and on the use of smart grids in the distribution network. In relation to evaluating the impact of the scenarios on the GB electrical network, an early version of the framework proposed in this thesis, as previously mentioned, was utilised for the GB transmission network and Pudjianto *et al.* [3.27] carried out a study for the GB distribution network.

The network reinforcement cost for the GB distribution network, required to meet peak demand for each of the scenarios, was estimated as a result of the scenario-related increase in the electrification of transport and heating. The level of network reinforcement was driven by thermal and voltage constraints, and the assessment included the effect of smart control and demand response to improve operation management, make efficient use of distribution network assets, and subsequently reduce peak demand. Simulations were carried out on different network topologies (rural and urban) – created to consider the varying network characteristics of the GB distribution system – using two different operating strategies against the smart grid approach; business as usual (passive demand and network) and smart control. The smart control strategy included the optimal management of plug-in vehicle charging, heat pumps, and voltage regulation on the network (the assumptions behind the modelling of each aspect are detailed in [3.27]).

In all three scenarios, a significant penetration of electric vehicles from 2030 to 2050 exists, however, for Thousand Flowers a reduced electrical heating demand was predicted as a result of more aggressive improvements in energy efficiency and housing insulation. The study showed that under the business as usual strategy, the required present cost of reinforcing the GB distribution network (using an estimated number of rural and urban networks to represent the GB system) between 2010 and 2050 was significant and could reach £36billion for Market Rules and Central Co-ordination, and £25billion for Thousand Flowers. This cost could be significantly mitigated however by using the smart control strategy, which could achieve a reduction of £20-£25billion across the 40 years (excluding the cost of applying the smart control scheme); a notable cause for utilising smart grid technology in the distribution network.

Phase two of the project '*Realising Transition Pathways*' is currently underway to extend and enhance the work of phase one, with a continued focus on the electrical sector and the electrical provision of heat and transport. New studies are being carried out on historical transitions (to inform the creation of future scenarios) and on 'branching points' of the core scenarios. In relation to the electrical network additional models have been developed and/or applied, as part of phase two, to evaluate the core transition pathways. These models are HAPSO (Holistic

Approach to Power System Optimisation) and HESA/UK+ (a combination of the Hybrid Energy System Analysis tool and UK+ models developed at the University of Strathclyde):

- **HAPSO** follows on from the work of Pudjianto *et al* [3.27] and is a bottom-up, cost minimisation model for the entire European power system. It includes a simplified representation of the GB, Ireland and continental Europe electricity systems, thereby enabling the modelling of power exchanges across the associated regions. The model locates the optimal generation, transmission, and distribution network infrastructure requirements, considering demand response (as modelled previously [3.27]), for a snapshot year of the scenario under study, to achieve network security and a sufficient level of system controllability. Generation investment decisions in the rest of the European system, as well as the short-term operation of the entire European system on an hourly basis, including hourly plant dispatch and the scheduling of reserve and frequency regulation services to balance the system, is optimised simultaneously. European-wide benefits of grid balancing can therefore be determined using the model, and a proportion of these benefits attributed to the GB system, depending on the scenario and year under study [3.28].

- **HESA/UK+** combines a hybrid energy system model, which is based on the energy hub concept [3.29], with the UK+ model, which contains information for the core pathways on the spatial disaggregation (across 17 onshore and 5 offshore zones) of generation and storage across the GB transmission and distribution system. The outputs from the UK+ model, feed into the HESA model, which can determine the least cost method to transport energy across coupled transportation systems. HESA utilises a modular framework to separately represent each component in a system prior to integration. These are known as energy hubs, which are used to represent the conversions of energy, between different energy carriers, into one mathematical form [3.30]. HESA utilises energy hubs to model and optimise, through the minimisation of energy flows using linear programming, the transportation, generation and storage of energy. The model can minimise the energy flows of gas, heat, electrical and $CO_2$ transportation (for CCS technology) for a single objective (i.e. cost or $CO_2$ production), in a simplified representation of a distribution (as studied in [3.30]) or transmission network, for the scenario under study.

The temporal and spatial resolution of the scenario-related technical feasibility studies carried out in phase one and two of the 'Transition Pathways' project are an improvement over those associated with other UK scenario research projects; namely *DECC 2050*, *LENS 2050* and the UKERC *Energy 2050* project. The framework proposed in this thesis was utilised in combination with FESA to evaluate, without temporal or geographical simplification, a scenarios requirement for national electrical transmission network reinforcement [3.21]. Several studies in phase two have since related to the scenario impact on the GB distribution network.

The 'Transition Pathways' project, in comparison, generated scenarios which emphasised the scale of the challenge in transforming the UK electricity system to meet low carbon governmental emission targets. As opposed to focusing on technological change and the associated economic impact, the scenarios generated – following an iterative combined qualitative and quantitative analysis procedure – included wider interactive changes to technologies, institutions, business strategies and user practices. The scenarios produced also considered the rate of change and effect, of previous energy transitions, in the evolution of the pathway narrative and associated quantitative generation mixes. A number of branching points as a result of unexpected/unplanned events during the duration of each scenario was also defined, creating potentially many more scenarios, where further technical feasibility studies could be carried out, resulting in a better understanding of the possibilities for transformation of the UK electricity system to a low carbon economy.

The 'Transition Pathways' project explored, more thoroughly, the plausibility and acceptability of the energy transitions proposed in each scenario. The role of changes in actors' habits, practices and wider social values, and the interaction with technological changes, in enabling a transition was explored. Further, the associated challenges for individuals/households, energy firms and policy makers, to realise the scenarios was included.

However, the initial quantification of the scenarios relied on expert judgement rather than a more sophisticated techno-economic model such as the MED model used in *LENS 2050* and the *UKERC's Energy 2050* project. Expected infrastructure investment costs, trade-offs between capital and operational costs of different generation technologies, and the resulting implications to energy service costs – a key influence to the feasibility of the scenarios generated – were therefore not assessed prior to the creation of the initial pathway narratives.

Conversely, the iterative and collaborative process behind updating the qualitative and quantitative background to the scenarios aimed to improve the technical and social feasibility of the scenarios.

## 3.6. *Conclusion*

Great Britain's existing electricity system is highly centralised and designed for large-scale fossil fuel and nuclear plant. It is clear from the key UK low-carbon studies included in this review that significant change in the generation mix and therefore the system as a whole is required for the electrical sector to achieve governmental emissions targets, especially under a number of scenarios which require high electrification in transport and heat. Many scenarios exist for the GB system, with a wide range of options for technological and societal change, and it is still apparent at this stage that the risks of adopting a single approach and restricting the system to a sub-optimal strategy are high. This could result in an inefficient, costly plan which did not harness the potential of emerging technologies. However, a business as usual approach to the transmission and distribution system is likely to continue, unless regulation and policy allows for change. Recently, to counteract this issue, the price control period and the Integrated Transmission Planning and Regulation (ITPR) project has been introduced by Ofgem to encourage network innovation in development and operation, whilst ensuring that the system is planned in an economic, efficient and coordinated way.

A common limitation found in the technical feasibility studies of the UK low-carbon research projects included in this review, is the spatial and temporal consideration of electrical generation and demand and constraints on the associated GB network. Whereas models have been developed to improve the spatial and temporal consideration of electrical generation and demand (MARKAL – plus model variants, WASP, and in particular FESA), and the impact of a scenario on the GB distribution network, the spatial impact of a scenario on the GB transmission network (excluding the use of an initial design of the proposed framework in the 'Transition Pathways' project) and the temporal impact on associated network constraints had not been adequately assessed.

A flexible, systematic transmission reinforcement planning approach, which considers sufficiently the spatial and temporal effect in the evaluation of the economic impact of future energy scenarios to the GB electrical transmission network is therefore required. This modelling approach could be used to improve current understanding on the economic impact of a wide range of penetrations in renewable and conventional generation. This will aid governmental energy policy and the reinforcement plans generated could be used to help the TNO/SO outline a coordinated long-term network reinforcement strategy.

## 3.7. *Chapter 3 Summary*

This chapter presents a critical review and discussion of key UK low-carbon research projects and the associated future energy scenarios which have been created. The ethos of the various scenario narratives, the scenario targets and aims, the methods used for scenario creation and the models used for scenario evaluation are discussed. An emphasis of the discussion is placed on the models used for scenario evaluation, establishing the need for a model to adequately assess the spatial and temporal economic impact of a future energy scenario to the GB transmission network.

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# Chapter 4

# 4. Design Methodology for the MOTREP Framework

## 4.1. *Introduction*

Chapter 1 discussed the need for network reinforcement and the importance of transmission planning for the GB network. This chapter also summarised the options available for network reinforcement, introduced approaches to transmission network planning, highlighted the methods currently employed for evaluating a scenario, and outlined the proposed modelling approach. Chapter 2 discussed the transmission planning problem and the multi-objective nature of network reinforcement. Further, meta-heuristic techniques used in multi-objective transmission planning under a deregulated electricity market environment were outlined and a critical review was carried out on the associated frameworks and modelling approaches. This review identified limitations in relation to the objectives of this thesis. Chapter 3 provided a review of key UK low-carbon studies and the associated energy scenarios, outlining the context of the scenarios, the methods employed in scenario creation, and the models/tools used in scenario evaluation. This review highlighted the need for a flexible, systematic modelling approach to adequately evaluate the spatial effect and economic impact of future energy scenarios to the GB electrical transmission network.

This chapter presents the proposed design of the multi-objective transmission reinforcement planning (MOTREP) framework used in this thesis for scenario analysis and the evaluation of transmission network impacts. The methods employed and the decisions, simplifications and assumptions made in the underlying framework to achieve the objectives of the thesis are described. The MOTREP framework has been designed and developed to generate transmission reinforcement plans (TRPs) that adhere to thermal constraint criteria defined by the NETS SQSS – a document which sets out a coordinated set of criteria and methodologies that transmission licensees shall use in the planning and operation of the GB electrical transmission network – reference to these rules are made throughout.

This chapter details the method used for allocating generation and electrical demand for the scenario across the network. The suitability of the DC power flow (DCPF) for estimating active power flows across the GB transmission network is discussed and the implementation of the DCPF and DC optimal power flow within the MOTREP framework is detailed. The systematic approach used to generate reinforcement solutions for the initial population (required by the SPEA2) is then described. The detailed calculation of each of the objectives used as attributes for the transmission planning problem is then explained, discussing, where further elaboration from Chapter 2 is required, the importance of each objective in the context of the planning problem. The SPEA2 method, including the adaptions made for the MOTREP framework, is detailed and the advantages of the SPEA2 for solving the multi-objective problem are outlined. Finally, the method employed in the MOTREP framework to carry out deterministic security testing of the resulting reinforcement plans is disclosed. Throughout this chapter possible improvements in the design of the framework are discussed where appropriate.

## 4.2. *Creating the Scenario Generation Mix*

Data on the transmission entry capacity (TEC), location (network nodes), connection date and commissioning date of each generating unit and interconnector, currently connected/expected to connect to the network is required to accurately create the scenario generation mix. For the 2020 case study involving the Gone Green scenario, this data was mainly obtained from the 2011 NETS Seven Year Statement (SYS) [4.1], and updated using the 2012 Electricity Ten Year Statement (ETYS) [4.2] for the 2035 case studies involving Market Rules and Central Co-ordination. The generation mix of a scenario was created by adding or removing generating units that have, respectively, a near term predicted connection date or a commissioning date that brings the units continued operation into question for the future scenario year. Similarly, the overall import and export capacity of a network can be increased or decreased for the scenario by varying the selection of interconnectors to external systems. Table 4-1 details an example of how this process is carried out for coal generation. A generation mix – required in the assessment of outage cost as a result of a TRP (see section 4.7.3.) – is also created for the base case network of the study, which will be expanded and reinforced to accommodate the scenario generation mix.

In Table 4-1, the capacity of coal generation is altered from the year of the base case network (in this case the year 2014) to match the requirement of the generation mix for year 2020 of the Gone Green scenario (developed by National Grid in 2011 [4.3]). The TEC used for the coal fired power stations includes capacity from small scale Open Cycle Gas Turbines (OCGTs) that are also utilised at the sites. Hence for simplicity this small proportion of the

**Table 4-1 Scenario related example for the allocation of coal generation**

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| IGCC | Hatfield | 800 | 800 | THOB40 | 2013/14 | n/a |
| BL | Aberthaw | 1665 | 1665 | ABTH20 | Connected | 1971 - 1979 |
| BL | Blyth | 0 | 0 | BLYT20 | 2020/21 | n/a |
| BL | Cottam | 2000 | 2000 | COTT40 | Connected | 1969 - 1970 |
| BL | Didcot A | 0 | 0 | DIDC40 | Connected | 1973 |
| BL | Drax | 3257 | 0 | DRAX40 | Connected | 1974 - 1986 |
| BL | Eggborough | 1940 | 1940 | EGGB40 | Connected | 1968 - 1969 |
| M | Ferrybridge | 1986 | 0 | FERR4A | Connected | 1966 - 1968 |
| BL | Fiddlers Ferry | 1987 | 1987 | FIDF20_SPM | Connected | 1971 - 1973 |
| BL | Ironbridge | 0 | 0 | IRON40 | Connected | 1970 |
| BL | Kingsnorth | 0 | 0 | KINO40 | Connected | 1973 |
| M | Lynemouth | 420 | 0 | BLYT20 | Connected | 1971 |
| BL | Ratcliffe-on-Soar | 2021 | 2021 | RATS40 | Connected | 1968 - 1970 |
| M | Rugeley | 1018 | 0 | RUGE40 | Connected | 1972 |
| BL | Tilbury | 0 | 0 | TILB20 | Connected | 1968 - 1972 |
| BL | Uskmouth | 363 | 363 | USKM20 | Connected | 2000 |
| B M | West Burton | 1987 | 1484 | WBUR40 | Connected | 1967 - 1968 |
| BL | Cockenzie | 0 | 0 | COCK20 | Connected | 1967 |
| BL | Hunterston | 0 | 0 | HUER40 | 2018 | n/a |
| BL | Longannet | 2284 | 2284 | LOAN20 | Connected | 1973 |
| **Total** | | **21728** | **14544** | **Scenario Target: 14545MW** | | |

overall power station capacity is considered as being fuelled from coal. In this case three types of plant are considered; Base Load (BL) operated plant, Marginally (M) operated plant and plant that uses an Integrated Gasification Combined Cycle (IGCC) to turn coal into a synthesis gas before it is combusted [4.4]. Plant that includes (or has been retrofitted) with CCS technology is not included for the year 2020 of this scenario.

When creating a scenario generation mix, the aim is to realistically meet the scenario target for each fuel type; hence other factors (in addition to the age of the plant) can come into consideration. For the case of coal generation in the UK, several plants have refused to comply with the LCPD (now part of the IED) and have been forced to close by 2015 [4.5]. Cockenzie, Didcot A, Kingsnorth and Tilbury power station closed before 2014 [4.6] and so are not included in the base case network and in the scenario generation mix for this example. Units 1 and 2 of Ferrybridge (essentially half of the power station capacity) and Ironbridge power station, which converted to biomass in 2013, also closed by 2015 [4.6]. Hence for this example, Ironbridge power station needs to be included as a biomass plant in the base case network (thus not included under coal generation) and excluded from the scenario generation mix. However, Ferrybridge power station has been completely excluded from the scenario generation mix, due to the prediction for this case study that the remaining units will eventually close by 2020. This prediction is based on the age of the plant, with units 3 and 4 of the plant (the remaining units beyond 2015) being commissioned in 1967 and 1968 respectively.

Further reductions in coal generation are needed for this case study and these reductions are achieved by removing Drax, Lynemouth and Rugeley power stations and a unit of West Burton power station from the scenario generation mix. Drax power station has been excluded as plans are in place to initially convert 3 of its 6 units to run on sustainable biomass [4.7]. Hence for this case study it is assumed that Drax power station will convert entirely to biomass by 2020. Lynemouth power station is also expected to convert to biomass [4.8], however plans for Rugeley power station to be converted have been scrapped [4.9] and it is expected in reality, and indeed for this case study, that Rugeley power station will close soon. The remaining reduction is achieved by removing a unit of West Burton power station (commissioned in 1967) which, following the above exclusions, contains the oldest remaining coal fired generating units in the scenario. For coal fired stations that are converting to biomass, should the capacity of the newly converted plant cause the scenario target for biomass generation to be exceeded, then the converted plant is not included in the scenario generation mix and is thus predicted to close.

For coal and gas generation, once the scenario target has been reached for each fuel type, plants that should be treated as operating marginally across the year, as opposed to being treated as a base load plant, are selected for the base case network year and the scenario year. It is expected that older plants will operate marginally as they near the end of their lifetime. Marginal plants are treated separately to base load plants as due to their operation, their position in the ranking order of generation to meet demand is lower than their base load equivalent. This affects the identification of contributory generating units to meet demand (see section 4.5.1.). Further, a plant operating marginally will submit different (often higher) bid and offer prices as part of the Balancing Mechanism (BM) compared to their base load equivalent; this affects annual constraint costs resulting from network congestion (see section 4.7.4.). For this case study, West Burton power station and three CCGT plants (Deeside, Keadby and Little Barford; all commissioned in 1994) were selected as marginal plant for the scenario year. West Burton is also defined as operating at base load for the base case network year.

For offshore wind, wave and tidal energy sources, designated areas can be used with a prescribed overall power capacity. For offshore wind generation, the designated areas for the case studies in this thesis are parts of the UK seabed leased by the Crown Estate (who owns or has vested in it the “Marine Estate” [4.10]). The prescribed power capacities of the designated areas were obtained from [4.11]. For wave and tidal generation, the designated areas and predicted power resources of these areas, for the case studies, were obtained from [4.12] and [4.13] respectively. The scenario target for each fuel type (offshore wind, wave and tidal) is achieved by increasing or decreasing the number of arrays of turbines within the designated area. The sizing of these arrays was based on those detailed in the NETS SYS [4.1] and ETYS [4.2].

Multiple network locations can be allocated in the framework for each power station or area of offshore generation. The capacity of each generating unit in this case is split evenly across the selected network nodes, decreasing network strain. In the case of offshore wind, wave and tidal powered generation, an onshore network node can be added upon the addition of a turbine array to the offshore area, should it be likely that the area can no longer be supported by the onshore substations chosen and the nearby onshore transmission infrastructure. Generally, for the case studies, a network node has been added when the incremented capacity of the offshore site exceeds around 3000MW when connected to the 400kV onshore network, 1500MW when connected to the 275kV network and 100MW when connected to the 132kV network (Scotland only). These general figures are less than the maximum power station capacity currently connected to each voltage level in the GB transmission system: Drax power station (3906MW), Longannet (2284MW) and Oldbury (430MW) for the 400kV, 275kV and 132kV networks respectively.

This procedure ensures that the base case network is not unnecessarily overloaded. Generators are unlikely to pay high connection costs for enabling transmission works if a cheaper option for onshore connection can be found. Hence this procedure aims to provide a more realistic case for the creation of a reinforcement plan. Onshore network locations for some generating units were not included in the NETS SYS [4.1] and ETYS [4.2]; particularly for offshore wind farm arrays. For these instances, analogous to the case of adding an extra network node, the node selected for the case studies is based on the closest node with the most suitable voltage level, and thus line capacity, for the size of generating unit/offshore array to be added. The following general rules have therefore been used to select a suitable network node:

- If the generating unit/offshore array has a capacity ≤ 430MW (matching the capacity of Oldbury) then a network node at any voltage level can be selected.
- If the capacity is > 430MW and ≤ 2284MW (matching the capacity of Longannet) then a 275kV or 400kV network node can be selected.
- If the capacity is > 2284MW then only a 400kV network node is selected.

This procedure again ensures that a realistic case for reinforcement is provided. Further, to ensure that only transmission connected generation is included in the scenario generation mix of the case study, each incorporated generating unit/offshore array is a large generator and meets the existing criteria for large generation in each TNO region of the GB network. For NGET in England and Wales, SPT in southern Scotland and SHE-T in northern Scotland, large generators generally regarded as being economically viable for transmission connection are defined as being ≥ 100MW, ≥ 30MW and ≥ 10MW respectively [4.14]. Hence, when adding a new generating unit these thresholds were taken into consideration.

A detailed list of the generating units/offshore arrays/interconnectors selected for each case study analysed in this thesis can be found in Appendix C.

## 4.3. *Scenario Demand Estimation*

The modelling framework utilises a peak value, assumed to be corrected for the ACS condition, and a median case study based minimum value (for calculating the outage cost of a TRP, see section 4.7.3.) to represent the transmission network demand of the scenario to be assessed. Thermal constraint criteria adhered to in the framework is outlined in the NETS SQSS and is based on the transmission network at ACS peak demand. Scenario generating unit outputs (see section 4.5.) are set in the framework against the ACS peak demand value and thermal network issues are defined. The ACS peak demand and a seasonal LDC are used in the framework to determine multiple demand levels for estimating annual network congestion and the resulting constraint costs (see section 4.7.4.).

Many definitions of electrical demand exist for a transmission network; ranging from demand that includes transmission losses, generating unit demand and exports to external systems (via interconnectors), to demand that excludes any one or all three of these characteristics [4.15].

Further, demand can be defined as 'unrestricted' or 'restricted'. The term 'unrestricted' relates to a demand level that takes no account of demand response or management from network loads; the term 'restricted' relates to the opposite case [4.16]. Hence for unrestricted demand, as an example, no load balancing from pumped storage stations can be assumed to occur at peak times. Network planning for the GB transmission system is based on ACS unrestricted demand as it is assumed that demand control cannot be fully relied upon at peak times [4.16].

The peak demand value used by the MOTREP framework is assumed to be unrestricted and corrected for the ACS condition, and must include transmission losses but exclude generating unit demand and exports to external systems. This is to match the definition of ACS peak demand used in the NETS SQSS [4.17].

### 4.3.1. Setting Network Nodal Demand

To simulate the power flow across each line in the transmission network, the level of electrical demand and generation output at each network node needs to be defined. Hence for any value of overall network demand (e.g. peak or seasonal LDC level) nodal demand needs to be set. This is achieved in the framework by maintaining the demand distributions at peak or minimum demand of the base case network across zones, used to split the transmission network into smaller more manageable regions. For the case studies in this thesis, these are generation zones which have been defined for the recent application of locational Transmission Network Use of System (TNUoS) charges.[8]

The framework assumes that peak demand occurs during the winter season and minimum demand occurs during the summer season. This is unlikely to change in the UK with the expected influx of electric vehicles, due in part to the increased use of demand response in smart distribution systems [4.18]. Further, an increase in summer demand from the greater use of air conditioning units, in growing industrial and commercial sectors, would likely be sufficiently counterbalanced by an increase in winter demand through the increased use of electric heating (particularly as grid supply becomes increasingly decarbonised). Eyre *et al.* [4.19] forecasted that by using electric heat pumps to meet peak heating demands of the UK residential sector in 2050, winter peak demand would increase by 40GW; a significant increase.

[8] These are charges which generating units connected to the transmission network must pay, and which are used to recover the cost of installing and maintaining the transmission system.

The base case network chosen, for the case studies analysed in this thesis, is a planned GB transmission network for 2014/15. The nodal demand for the base case network, as well as data on the generation zone of each network node, and all other necessary network data to carry out a DCPF (see section 4.4.) and cost calculations (i.e. route length data), was obtained from the 2014/2015 data spreadsheets in [4.20]. The MOTREP framework uses an input, in the form of a matrix, which details the percentage contribution of each zone in the base case network to total demand for winter and summer. Base case network nodal demands for both minimum demand (i.e. during the summer season) and peak demand (i.e. during the winter season) are used to generate a nodal demand distribution for each zone of the network and for the season under simulation, to match the specified total.

Negative nodal demands can exist in the data due to the effect of embedded generation. In these instances, the embedded generation at the network node exceeds electrical demand. In other locations embedded generation can be insufficient to meet local demand but still reduce demand at the node. Hence, when creating the demand distribution for each zone, for the year of the scenario to be analysed, instances of negative nodal demand are treated the same as instances of positive nodal demand. The electrical demand at each node in the base case network is set for the required scenario demand total (at peak or seasonal LDC level) using the following formulation:

$$ND_j = SD_{zone} \times \left(\frac{BND_j}{BD_{zone}}\right) \tag{4-1}$$

where $ND_j$ is the MW active power demand at the $j$th nodal demand site of the base case transmission network for the level of scenario demand in MWs required at the associated network zone, $SD_{zone}$; $BND_j$ is the MW active power demand (during winter peak or summer minimum) at the $j$th nodal demand site of the base case transmission network, and $BD_{zone}$ is the total associated zonal demand in MWs for the base case transmission network (winter peak or summer minimum).

If for example scenario peak demand is greater than the peak demand of the base case network, then this method will result in instances of negative nodal demand (within each zone) decreasing in size and instances of positive demand increasing in size. Hence it could be assumed in this case that embedded generation at the nodes of negative demand has increased and embedded generation at the nodes of positive demand has potentially decreased. Figure 4-1 details the zonal split of seasonal network demand across GB for the 2014/15 base case network used. The method employed in the framework allows the user to alter the electrical demand at zones across the network, enabling the distribution of demand within the defined zones to be altered from the base case. For the case studies analysed in this thesis, the distribution of electrical demand is assumed to remain the same as the base case network.

| Zone | Winter Demand (% of peak) | Summer Demand (% of minimum) |
|---|---|---|
| 1 | 0.30 | 0.25 |
| 2 | 0.17 | 0.22 |
| 3 | 0.05 | 0.13 |
| 4 | 0.73 | 0.56 |
| 5 | 0.07 | 0.06 |
| 6 | 3.21 | 3.18 |
| 7 | 2.85 | 2.75 |
| 8 | 0.02 | 0.00 |
| 9 | 13.12 | 11.90 |
| 10 | 3.74 | 3.54 |
| 11 | 0.41 | 0.35 |
| 12 | 0.00 | 0.00 |
| 13 | 11.65 | 11.72 |
| 14 | 22.41 | 21.12 |
| 15 | 8.01 | 9.45 |
| 16 | 8.87 | 10.87 |
| 17 | 6.26 | 6.45 |
| 18 | 12.28 | 11.80 |
| 19 | 3.84 | 3.83 |
| 20 | 2.01 | 1.82 |
| **Total (MW)** | **59900.87** | **22711.24** |

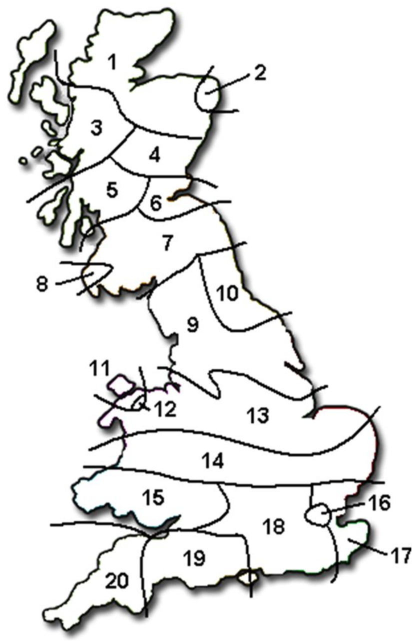


**Figure 4-1 Seasonal zonal demand distribution for the 2014/15 base case network**

## 4.4. *DC Power Flow and DC Optimal Power Flow*

The DCPF is a simplification of a full ACPF and looks only at active power flows; neglecting issues related to voltage magnitude, reactive power management and transmission losses [4.21]. For the case of formulating active and reactive power flows in a full ACPF, a minimum of four variables are required per network node – voltage angle, voltage magnitude, active power injections and reactive power injections. The only variables in a DCPF are voltage angles (where the differences between voltage angles at each node are assumed to be small) and active power injections. The iterative nature of an ACPF (particularly for large systems) requires a greater simulation time than a DCPF. More information on the DCPF and ACPF model can be found in Chapter 2 (section 2.2.2.).

For the case of the GB transmission network, the main network issues for the outlook of generation connections are related to thermal constraints; the planned (and/or recently completed) reinforcements outlined in Chapter 1 are primarily designed to alleviate expected thermal constraints. Further, the associated costs to alleviate a network issue of this type as opposed to a voltage related issue are likely to be much higher. Therefore, by using a DCPF and focusing on the thermal capacity impacts on the GB network of a scenarios generation mix, an economic assessment can be made that incorporates most the associated network reinforcement costs. Further the need to simplify the power flow problem – avoiding repeated iteration in every power flow calculation – brings computational savings to the optimisation process of the MOTREP framework.

The optimisation of network reinforcement is used in this thesis to evaluate multiple scenarios. Hence computational savings in this process enables solutions to be obtained in a realistic time horizon. However, the robustness of the solutions generated by the MOTREP framework and the resulting economic scenario-based conclusions therefore rely on the accuracy of the active power flows formulated by the DCPF. If the active power flow is inaccurate then this presents a false, unrealistic problem for network reinforcement.

### 4.4.1. The Suitability of DCPF for the GB Transmission Network

Purchala *et al*. [4.21] and Stott *et al*. [4.22] analyse active power flows from a DCPF in comparison to the active power flows generated by an ACPF, to derive the power flow accuracy of the DCPF and determine the suitability of using a DCPF on high voltage transmission networks. Hence the assumptions of the DCPF are looked at in detail. These assumptions are that the difference between nodal voltage angles is small, line resistances are negligible and the voltage magnitude at each node is flat.

For the assumption of negligible resistance, one of the questions answered by Purchala *et al*. [4.21] is how low the X/R ratio of line parameters can be for the DCPF to generate acceptably accurate active power flows in comparison to the ACPF. From analysing multiple line parameters in a 30-node test network it was defined that for higher values of line resistance (i.e. $> 9\Omega$), the X/R ratio of network line parameters must exceed 4 to ensure the error between DC and AC active power flows remains under 5%. For lower values of line resistance (i.e. $\leq 5\Omega$), an X/R ratio higher than 2 is more than sufficient. Hence the lower the line resistance the lower the required X/R ratio for good accuracy in DCPF active power flow estimation. This is due to the effect line resistance has on both total line impedance, a key factor for the power flow pattern, and active power losses. A network with low line resistance, common in high voltage systems, will have low power losses and thus the exclusion of active power losses from the DCPF is less detrimental to the accuracy of the output.

For the planned GB 2014/15 base case transmission network used for the case studies in this thesis, the average X/R ratio of the lines is 8.11, and furthermore 31.42% and only 6.32% of the lines in the network fall below an X/R ratio of 4 and 2, respectively. Purchala *et al*. [4.21] details the influence of the X/R ratio on the error in active power flow estimation, when using a DCPF, for a given range in resistance. For line resistances less than 1Ω, the error in active power flow estimation will be less than 1%, regardless of the lines X/R ratio. For the case of the 2014/15 GB network, 86.67% of the transmission lines have a resistance under 1Ω. Hence for the assumption of negligible line resistance, the active power flows defined by a DCPF across the majority of lines in the base case network could be within a 1% error of the active power flows defined using an ACPF.

Figure 4-2 details the X/R ratio and resistance of each circuit in the 2014/15 base case GB transmission network. Several outliers exist where resistance of the circuit is retrospectively high and the associated X/R ratio is low. However, according to Purchala *et al*. [4.21], only two of these circuits (as highlighted red in Figure 4-2) could have an error in active power flow estimation, as a result of the DCPF assumption of negligible resistance, which is greater (narrowly) than 5%. These circuits represent a 132kV, 63.4km OHL from Broadford to the network connection of Quoich hydro power station in the north west of Scotland, which has an X/R ratio of 1.65 and a resistance of 8.99Ω, and a 132kV, 93.8km OHL from Mybster to Shin in the north of Scotland, which has an X/R ratio of 2.29 and a resistance of 9.54Ω.

The voltage related assumptions of the DCPF (i.e. the difference between nodal voltage angles is small and the voltage profile at each node is flat) according to Purchala *et al*. [4.21] – who use an example of the Belgian HV network at a peak demand of 13GW – can have a more severe impact on the accuracy of the DCPF. For voltage angle differences the error in active power flow estimation is unlikely to exceed 1%. However, the assumption that per-unit voltage is equal at each node in the network is more detrimental to the accuracy of the DCPF. Purchala *et al*. [4.21] analyses the influence of voltage fluctuations on the active power flow estimation

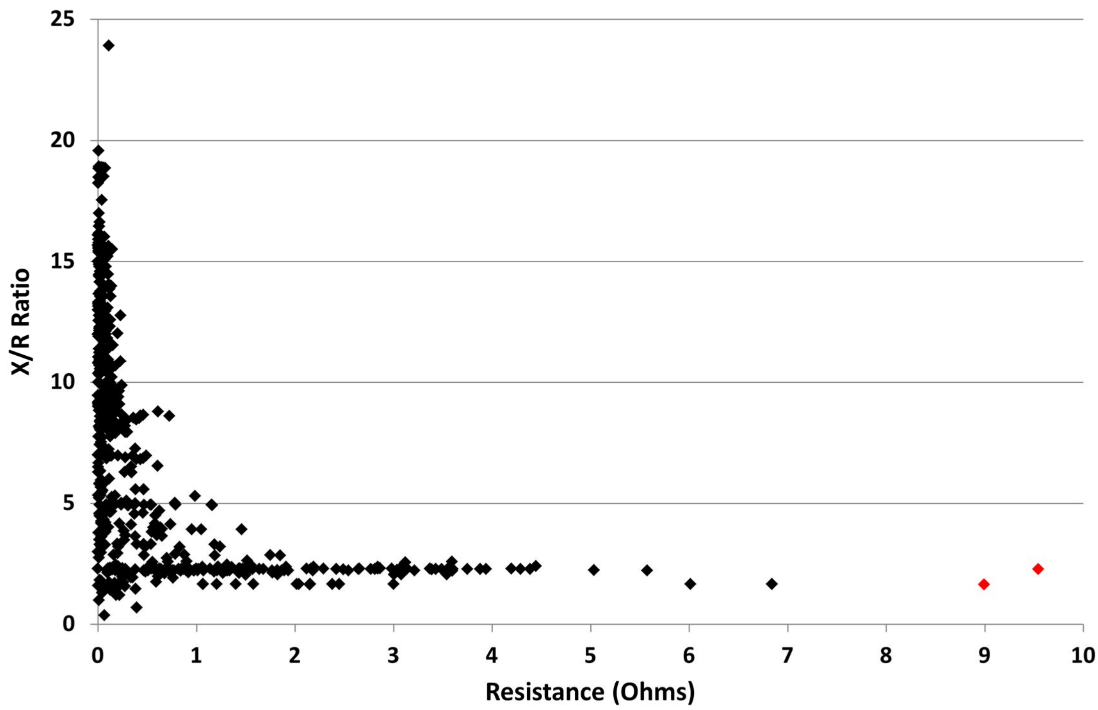


**Figure 4-2 X/R ratio and resistance of each circuit in the 2014/15 base case GB transmission network**

error of the DCPF for different X/R ratios. As the average X/R ratio of the lines in the GB network is 8.11, an average DCPF estimation error of around 3% could result in the case studies. This is again a relatively low estimation error; however, this is an average and it follows for an 8.11 X/R ratio that the maximum estimation error of some of the lines could reach around 80%.

Overall, the assumptions of negligible line resistance and a small difference between nodal voltage angles do not raise significant concerns for the accuracy of the DCPF to simulate active power flows on the GB transmission network. However, the assumption of a 1 per-unit voltage across the network can cause significant estimation errors across a small number of lines. Despite these potential errors, for scenario analysis on the GB network, the computational savings from using a DCPF in comparison to an ACPF is a significant advantage and outweighs the potential errors of the DCPF. Further, due to the assumptions made, a DCPF requires less network data than an ACPF and this data is easier to obtain, particularly for a large-scale multi-voltage network.

## 4.4.2. Implementing the DCPF and DCOPF

The MOTREP framework is implemented in Matlab and uses Matpower to carry out DCPF and DC optimal power-flow (DCOPF) calculations [4.23]. Whenever a DCPF or DCOPF is required to be calculated, the framework is designed to generate (from several user-defined inputs) the required input data for the solver. This input data is specified in a set of data matrices packaged as the fields of a Matlab struct. In the case of running a DCPF these data matrices consist of a matrix for bus data, generator data and branch data (or transmission line data).

For bus data, the DCPF requires the bus number, bus type (1 = no generator connection, 2 = generator connection, 3 = reference bus, 4 = isolated), real power demand (MW) and base voltage (kV). Voltage magnitude is assumed to be 1 per-unit. For generator data, the DCPF requires the bus number, the real power output (MW), the voltage magnitude set-point (inputted as 1 per-unit), the apparent power base (set to the system wide apparent power base for the case of DCPF) in MVA, status (> 0 = generator in-service, ≤ 0 = generator out-of-service), maximum real power output (or TEC of the generating unit) in MW and the minimum real power output (inputted as 0MW) of all generating units connected to the transmission network.

For branch data, the DCPF requires the bus number at the "from" end and "to" end, reactance (in per-unit), thermal line rating for the season of simulation (MVA) and status (1 = in-service, 0 = out-of-service) of each line and network component. Resistance values (in per unit) for each line are not needed in the DCPF, however they have been included in the input data, and therefore branch data matrix, to calculate resistive heating losses for computation of the annual line loss saving objective (see section 4.7.2.).

The DCPF simulates active power flows throughout the network, without constraining the power flow magnitudes and generator outputs to thermal line limits and minimum or maximum generation output limits respectively. Hence the real power output of each generator needs to be defined prior to carrying out a DCPF simulation, with the precondition that total generation matches total demand. If the real power output of each generator is not defined, or total generation does not meet demand, then all required generation, regardless of the maximum output limit, is obtained from the reference bus. The reference bus for the scenario is thus allocated in the MOTREP framework to the bus with the highest capacity of in-service generation. The MOTREP framework sets scenario generating unit outputs to match demand using the methods detailed in section 4.5. This ensures that the reference bus isn't used for balancing supply and demand.

The standard DCOPF includes linear constraints such as generator output limits and branch flow limits and has an objective to minimise the summation of individual polynomial cost functions of real power injections for each generator. Hence the DCOPF optimises real power outputs of each generator in-service. An extension of the DCOPF in Matpower enables the capability to handle non-smooth piecewise linear cost functions, which is used in the MOTREP framework to model discrete bid and offer prices submitted in the Balancing Mechanism (BM). To carry out a DCOPF an extra data matrix is required for generator cost data. The DCOPF requires, in addition to the data for a DCPF, the type of cost model used (1 = piecewise linear, 2 = polynomial), the number of cost coefficients or data points used in the polynomial or piecewise linear cost function and the parameters defining the total cost function, for each generating unit connected in the network model.

Several different solvers can be used through Matpower to resolve the DCOPF problem; as detailed by Zimmerman *et al*. [4.24]. Appendix A.1. details the results of a number of solvers for running a DCOPF with piecewise linear generator costs; a linear programming problem. The solvers are tested and used here to calculate constrained off generation and the resulting cost of constrained on generation through the Balancing Mechanism. Matpowers own solver, known as MIPS (Matlab Interior Point Solver), is found to continually output the most economic plan for constraining on/off generation, and is thus the chosen solver for carrying out a DCOPF within the MOTREP framework. Zimmerman *et al*. [4.24] details the methods used in Matpower for MIPS and indeed for DCPF and DCOPF (including the treatment of polynomial and piecewise linear cost functions).

## 4.5. *Setting Scenario Generating Unit Outputs*

For the case studies in this thesis, the MOTREP framework is tested against the application of UK energy scenarios to the GB transmission network. Hence, due to the use of a DCPF model of the network under study, the framework to be practical, is required to create reinforcement plans that adhere (where applicable) to rules outlined in the NETS SQSS [4.17]; in this case rules on thermal constraints only. The NETS SQSS states that at ACS peak demand and prior to any fault on the GB transmission network, there shall not be any equipment loadings exceeding the pre-fault capacity rating[9] under the condition that generating unit outputs and power flows are set to those that arise from the Economy Planned Transfer Condition (EPTC). Before the EPTC method can be applied to a scenario, the MOTREP framework identifies the transmission connected generating units which are likely to operate at peak demand for the scenario.

### 4.5.1. Identifying Contributory Generating Units

The number of transmission connected generating units deemed to contribute to peak demand is dependent upon the plant margin of the scenario. A plant margin, using the definition in the NETS SQSS, is the amount by which the total installed capacity of generation (transmission connected and large embedded power stations) exceeds the net amount of the ACS peak demand minus the total imports from external systems [4.17]. Additional generation capacity is required for security purposes. Plants may become unavailable during peak demand, due to routine maintenance or breakdown. Further, with regards to future planning, plants under construction may not be commissioned on time and peak demand forecasts may be underestimated. For evaluating a scenarios plant margin, exports to external systems are treated as positive demand. The plant margin is normally expressed as a percentage using the below formulation:

$$Plant\ Margin = \frac{Total\ Capacity - \ (ACS\ Peak\ Demand\ \pm \sum_k INT_k)}{ACS\ Peak\ Demand\ \pm \sum_k INT_k} \times 100 \qquad (4\text{-}2)$$

where $INT_k$ is the MW export or import contribution from the $k$th interconnector to an external system.

In calculating the plant margin the contribution from interconnectors is determined first. Here, the expected levels of exports and imports are simply estimated based on the prevailing total plant TEC/demand balance of the GB system, rather than a model of the European electricity market. For the case studies in this thesis, full export to Ireland (i.e. to Northern Ireland and to the Republic of Ireland) is assumed during this process to match current operational experience of the Moyle interconnection to Northern Ireland. Hence contributions are only determined for the remaining interconnectors included in the scenario.

[9] This is the maximum continuous rating of a circuit without time limitation [4.17].

To determine the remaining interconnector contributions the method detailed in the NETS SYS [4.25] is used by the framework. Firstly, an initial margin of installed transmission connected generation over demand is determined, without imports or exports across the interconnectors (except in this case for exports to Ireland). The resultant margin is then used to estimate the level of imports or exports across the interconnectors. For an initial margin up to 25%, full import capability of the remaining interconnectors is assumed. For an initial margin of 45% or over, full export capability of the remaining interconnectors is assumed. For an initial margin between 25% and 45%, a linear reduction in exports/increase in imports is assumed such that, at a margin of 35%, there are no imports or exports across the remaining interconnectors. The import and export contributions of the interconnectors are then used to calculate the plant margin of the scenario using (4-2).

A plant margin equal to 20% is deemed to be the minimum requirement for the security of future electricity supply [4.26]. This stems mainly from the assumption that only 85% of total generation capacity could be predicted to be available at the time of winter peak demand several years into the future [4.26]. Using an availability factor of 85% results in a generation capacity requirement equal to 118% of peak demand. The remaining 2% of the 20% plant margin requirement is used as an allowance for other factors such as the underestimation of future peak demand [4.26]. The requirement of a 20% plant margin is used in this method to identify generating units that contribute to scenario peak demand. Once the scenario's plant margin has been calculated, and the margin is found to exceed 20%, a generator type ranking order is used for the scenario. The smallest contributory transmission connected generating unit of the lowest ranking generator type is removed until a plant margin of 20% or lower is achieved.

Other definitions exist for a margin of supply capacity over demand. Namely a de-rated capacity margin where the capacity of generation is not taken as the sum of plant TEC, but as the sum of de-rated plant capacity, where each capacity is adjusted to reflect the statistically expected level of reliable availability from that plant type during the winter season [4.27]. For example, currently in the UK nuclear plants would have a capacity de-rated to match an availability of 81% for meeting demand during the winter season [4.27]. This de-rated method has been created to deal with the increasing contribution of variable resources, whose average output is often considerably less than the TEC of the plant. When comparing the two margins it has been stated that a 20% plant margin is roughly equivalent to a 4-5% de-rated capacity margin [4.27]; however, this comparison can change depending on the generation mix and plant availabilities assumed.

Considering the option to use a de-rated capacity margin, the modelling framework identified in this thesis uses the guide of a 20% plant margin to define contributory generating units, matching the method in the NETS SQSS [4.17]; however, the generation capacity from wind, tidal and wave energy sources (sources with the lowest availability) can be de-rated, for the calculation of plant margin, to match the expected availability of the source at ACS peak demand.

### 4.5.2. Application of the Economy Planned Transfer Condition

Following identification of contributory generating units, the power output of the units at ACS peak demand for the scenario is set by the MOTREP framework using the EPTC method (Appendix E of the NETS SQSS [4.17]). The EPTC method, as outlined in Chapter 2, requires that there is sufficient transmission system capacity to accommodate all types of generation to meet varying demand levels efficiently. To carry out the method, specified generating unit types are firstly scaled down directly, using availability parameters. For nuclear units, 85% availability is assumed. For wind units, 70% availability is assumed (for both onshore and offshore wind) and for pumped storage generation, 50% is assumed. These availabilities have been derived from a network based CBA carried out by the NETS SQSS working group (comprising of the three GB TNOs – NGET, SPT and SHE-T), seeking to identify an appropriate balance between system operating costs (from network constraints and line losses) and the cost of transmission reinforcement (construction and maintenance costs) [4.28]. Hence, both nuclear and wind generation is assumed to have a higher availability than is expected (particularly in the case of wind), due partly to the high cost for the SO of these generator types in the Balancing Mechanism (BM), and therefore the generator types effect on annual constraint costs (see Table 4-4 in section 4.7.4).

For the case studies analysed in this thesis, should CHP plants or wave, tidal or biomass generating units be included in the scenario, then wave and tidal units are given the same availability as wind units, and CHP and biomass units the same availability as nuclear units. This is due to the similarity between the annual operation and BM cost of the plant types (see Table 4-4), which defines each generating unit's effect on annual constraint costs and the NETS SQSS working group CBA. The availability parameters used and generator types chosen for direct scaling are defined as inputs to the MOTREP framework and so can be varied. This is important for analysing diverse energy scenarios for differing years, which will involve varied costs in the BM.

After directly scaling down specified generating units the remaining units are scaled down using a scaling factor such that their aggregate output is equal to the demand level, plus or minus interconnector export or import contributions, minus the total output from directly scaled units. The EPTC method can be expressed as follows:

$$P_{Ti} = \begin{cases} A_T \times TEC_{DTi} \\ SF \times TEC_{VTi} \end{cases} \tag{4-3a}$$

where

$$SF = \frac{\sum_j ND_j \pm \sum_k INT_k - \sum_{DT}(\sum_l (A_T \times TEC_{DTl}))}{\sum_{VT}(\sum_m TEC_{VTm})} \tag{4-3b}$$

and $P_{Ti}$ is the MW output of the $i$th contributory generating unit of generating type $T$; $A_T$ is the availability for directly scaling down generating type $T$; $TEC_{DTi}/TEC_{DTl}$ is the MW transmission entry capacity of the $i$th/$l$th directly scaled contributory generating unit of type $DT$; $SF$ is the scaling factor; $TEC_{VTi}/TEC_{VTm}$ is the MW transmission entry capacity of the $i$th/$m$th variably scaled contributory generating unit (scaled by $SF$) of type $VT$; $ND_j$ is the MW active power demand at the $j$th nodal demand site of the transmission network including transmission losses, and $INT_k$ is the MW export or import contribution from the $k$th interconnector to an external system, determined during the process for identifying contributory generating units.

The scenario-based peak demand value for the framework must include the total expected active $I^2R$ heating losses from transmission lines and other network components to satisfy the numerator of the scaling factor equation. After applying the EPTC method, the import or export contribution of each interconnector is added respectively at the specified network locations to the list of identified contributory generating units (in the generator data input matrix for implementing a DCPF/DCOPF) or to nodal demand (in the bus data input matrix).

The EPTC method, as a result of being included in the NETS SQSS, is specific to case studies relating to the GB transmission network, and is part of current planning practice. While the MOTREP framework has been designed to be flexible, enabling availability parameters and generator types chosen for direct scaling to be varied in the application of the economy criterion, it is recognised that the EPTC method may not be suitable for other transmission networks. However, the framework has been designed to embrace modularity and therefore each step in the process is a separate component which can be replaced or easily adjusted for the requirements of the case study. The method for identifying contributory generating units and the EPTC method are both separate components in the framework which can be easily replaced with a new method or approach.

## 4.6. *A Systematic Approach to Generating Reinforcement Solutions for the Initial Population*

Creating an initial population of feasible reinforcement plans that are full of variety and good quality reinforcement solutions is crucial to reducing the simulation time required for the multi-objective optimisation; potentially preventing a Genetic Algorithm (GA) from prematurely converging to local optima. The modelling framework uses a GA formulation known as the SPEA2, which can also be described as a meta-heuristic MOEA technique [4.29]. This multi-objective algorithm is utilised to explore a pre-defined search space of possible solutions to improve the objective evaluations of the initial population, through an iterative process of population evolution, until a final non-dominated, Pareto-optimal set of TRPs is obtained. Figure 4-3 shows a flow chart of the systematic method employed to generate reinforcement solutions for the initial population. The evaluation of annual constraint cost saving ($CC_{SAV}$) is used to determine whether a reinforcement plan should be included in the initial population; if a TRP can achieve a saving in annual constraint costs then the plan is to be included, otherwise the plan is excluded. This ensures an initial population of high quality solutions, where each plan can alleviate (to some extent) network congestion on the base case network. Alleviating network congestion is a key objective in transmission planning and the associated potential economic impact can be significant, particularly for the GB transmission network. Hence a minimum requirement of a TRP should be to achieve an annual constraint cost saving.

The primary aim of the MOTREP framework is to assess the economic impact of multiple future energy scenarios through analysing the resulting set of Pareto-optimal reinforcement plans. This differs from some traditional transmission planning models, where the primary aim is to determine the best plan for a fixed scenario, given (in some cases) a set of pre-determined reinforcement options. Due to this change in application, structurally the framework adopts a

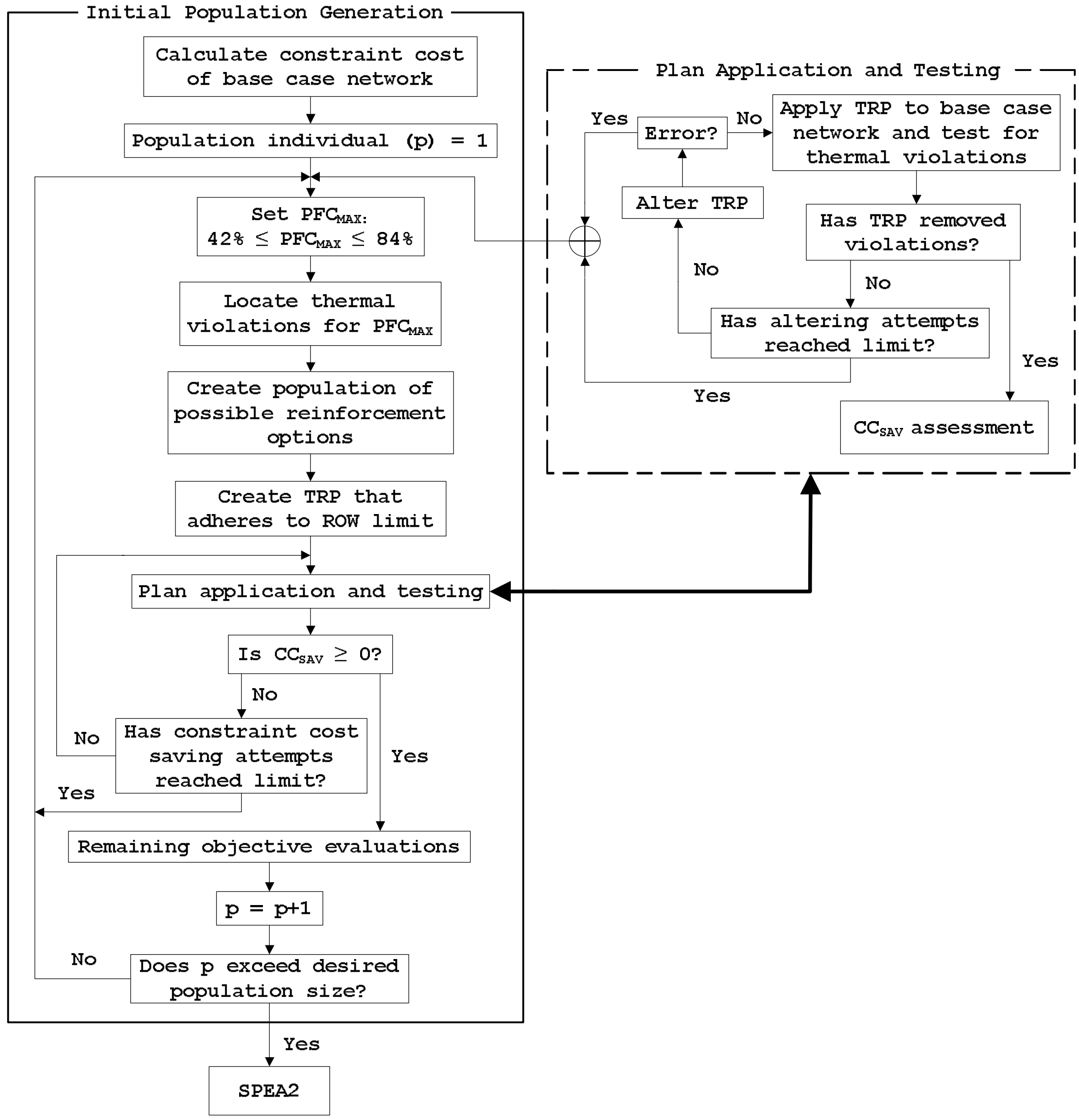


**Figure 4-3 Flowchart of the systematic method employed to generate reinforcement plans for the initial population**

systematic approach that is designed to generate, for any future energy scenario, its own reinforcement solutions; thereby eliminating the need for a set of pre-determined scenario specific transmission reinforcements. This improves the flexibility of the framework and enables the assessment of multiple energy scenarios to be carried out with increased ease.

To generate reinforcement solutions and explore a wide range of TRPs, a maximum power flow condition, $PFC_{MAX}$, is selected for each population individual between user-defined limits; chosen for the case studies in this thesis as 84% and 42% (i.e. half of 84%). The maximum power flow condition is a constraint, which the generated TRP must satisfy, on the maximum power flow (as a percentage of line capacity) across any line in the network (base case network and TRP) under peak demand. The maximum power flow condition is a pre-fault limit and is applied to the intact network. For thermal constraint criteria, a pre-fault rating of around 84% of the post-fault continuous rating is believed to be suitable to restrict the risk of exceeding equipment temperature to a suitable value [4.30]. Further, a study carried out on a model of the 2009 GB network at ACS peak demand found that the largest pre-fault power flow on a single line was 84% of the line rating.

The 84% limit in this application is the most onerous power flow condition for the network. Hence by varying $PFC_{MAX}$ a reinforcement plan is created for a scenarios ACS peak demand that either improves GB network thermal security, by increasing the surplus capacity of the network (to cater for added generator connection after the scenario year), or matches current thermal security through maintaining surplus capacity. The thermal limit violations that result from the selected power flow condition are then located, using a DCPF, following the identification of contributory plant at ACS peak demand for the scenario, and the setting of generating unit outputs using the EPTC method.

Figure 4-4 details the number of thermal limit violations that result in the unreinforced and unexpanded base case network (2014/15 GB transmission network) from varying levels of maximum power flow condition for year 2020 of the Gone Green scenario (developed by National Grid in 2011 [4.31]). It is clear from Figure 4-4 that the resulting TRPs from the MOTREP framework, for the defined case study limits in $PFC_{MAX}$, will contain reinforcements at a large range of locations; from around a minimum of 50 locations to a maximum which is likely to exceed 210 locations due to the likelihood that the network reinforcements employed exacerbate thermal constraints.

Due to the positive exponential trend in Figure 4-4 for the number of resulting thermal limit violations for the case study (with a significant increase between a $PFC_{MAX}$ of 48% and 42%), a $PFC_{MAX}$ of 42% was deemed a suitable lower limit to create the search space of TRPs for the SPEA2 to explore. This ensures that reinforcements are often not solely applied to lines where thermal capacity is a pressing issue. The solution search space is therefore broadened to include potentially helpful candidate reinforcement solutions for the multi-objective problem, enabling a more comprehensive multi-objective analysis to be carried out for the energy scenario.

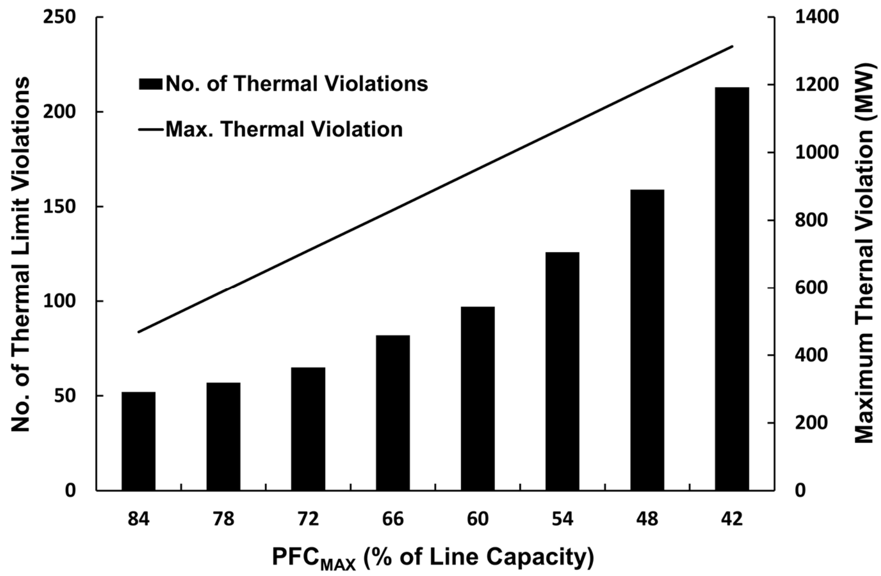


**Figure 4-4 Number of thermal limit violations observed (in excess of $PFC_{MAX}$) and the maximum MW thermal violation observed (above $PFC_{MAX}$) for the Gone Green scenario (year 2020) under varying levels of $PFC_{MAX}$**

For each newly defined thermal limit violation, located under the selected $PFC_{MAX}$, three reinforcement options are generated; namely an option for line reconductoring, one for single-circuit line addition and one for double-circuit line addition. The capacity of these reinforcement options is given as:

$$MVA_{UPG}|MVA_{ADD} = DCPF_{LINE}/(PFC_{LINE}/100) \tag{4-4a}$$

where

$$PFC_{LINE}^{Min} \leq PFC_{LINE} \leq PFC_{LINE}^{Max} \tag{4-4b}$$

$$MVA_{ORIG} < MVA_{UPG} \leq MVA_{VOLT} \tag{4-4c}$$

$$MVA_{ADD} \leq MVA_{VOLT} \tag{4-4d}$$

and $MVA_{UPG}/MVA_{ADD}$ is the MVA line capacity of the proposed upgrade/circuit addition (for single-circuit or double-circuit addition); $MVA_{ORIG}$ is the original line capacity of the line; $MVA_{VOLT}$ is the line capacity limit for the voltage level of the line; $DCPF_{LINE}$ is the MW power flow across the line determined by a DCPF; $PFC_{LINE}$ is the power flow condition of the line, selected between the pre-defined power flow condition limits of the minimum value, $PFC_{LINE}^{Min}$, and maximum value, $PFC_{LINE}^{Max}$.

The maximum line ratings of each voltage level in the base case network are used for $MVA_{VOLT}$. The maximum values found for the 2014/15 GB base case network (used for the case studies analysed in this thesis) are 500MVA, 1910MVA and 3820MVA for the 132kV, 275kV and 400kV voltage levels respectively. For $PFC_{LINE}^{Min}$ and $PFC_{LINE}^{Max}$ the values of 20% and 84% are chosen. The limits for $PFC_{LINE}$ are inputs to the framework and can be altered. The value chosen for $PFC_{LINE}^{Min}$ is the average power flow condition observed across all lines in the 2009 GB transmission network under ACS peak demand. A pre-defined number of attempts at locating a satisfactory line capacity (an input to the framework, determined empirically) are allowed, to alleviate the thermal limit violation discovered from the chosen $PFC_{MAX}$ of the reinforcement plan, and satisfy the constraints (4-4b) to (4-4d).

If a line capacity cannot be found, then the rating of that reinforcement option is set to the original line capacity of the line. An updated line capacity for that reinforcement option can be found later in the process, namely through carrying out the method employed for altering a TRP (described below and outlined in Figure 4-5), depending upon the reinforcement options selected for the line. If however a satisfactory line capacity has been discovered, per unit resistance and reactance values are updated for the new line's thermal rating (required to ensure accuracy of any line loss calculations and the DCPF itself) using suitable normalised per-km resistance and reactance per unit parameters, obtained for a large range of line capacities, from the base case network. The normalised line parameters chosen are those from a line at the same voltage level, with a capacity nearest to the new lines proposed rating.

Following the generation of reinforcement options, TRPs are created by selecting any combination of upgrade, single-circuit and double-circuit addition that ensures the right-of-way (ROW) constraint is adhered to. The ROW constraint defines the maximum number of circuits that can be installed at a specific location. The ROW constraint can be represented as follows:

$$0 \leq N_{ij} \leq N_{ij}^{Max} \tag{4-5}$$

where $N_{ij}$ and $N_{ij}^{Max}$ respectively represent the total number of circuits and the maximum number of circuits that can be added to the network route *i-j*. At certain locations of the GB network two double-circuits, or one double-circuit and two single-circuits, are found to connect along the same route. Hence for all case studies in this thesis, a ROW constraint of 4 is used to limit the quantity of circuits allowed and to ensure the creation of realistic TRPs within the framework. The maximum level of circuit addition, through adding a single-circuit and a double-circuit, can therefore only be applied to an existing single-circuit. If the thermal limit violation occurs across a double-circuit, then only a single-circuit or a double-circuit can be added.

After creating a reinforcement plan, the method for plan application and testing, as shown in Figure 4-3, is used. The plan is applied to the base case network and tested for thermal limit violations above the minimum condition for surplus network capacity; the most onerous power flow condition (in this case an 84% $PFC_{MAX}$). If no thermal limit violations exist, the annual constraint cost saving of the TRP is evaluated. If however thermal violations are discovered, then the plan is altered using the method shown in Figure 4-5. The iterative plan application and testing process allows for several attempts at altering the plan and finding a successful solution that eliminates thermal violations (above the most onerous power flow condition), thereby giving the initial TRP design the opportunity to succeed. Only minimal necessary alterations to the TRP design are made to maintain, as far as possible, the initial plan characteristics.

The process for altering a reinforcement plan involves increasing the capacity level of the previous reinforcement selections or selecting new reinforcement options (if the required increase in capacity level cannot adhere to the $MVA_{VOLT}$ constraint), under the stipulation that thermal limit violations (as defined following a DCPF) remain at the same locations. If the previous reinforcements made to the network exacerbated the thermal security issue further and caused thermal limit violations in excess of the most onerous power flow condition to occur at new locations, then the plan is altered to include new selected reinforcement options for this new location, that adhere to the ROW limit. The process for determining the new altered capacity of the reinforcement follows the procedure as formulated in (4-4), again allowing for a pre-defined number of attempts at locating a satisfactory line rating.

Each new attempt at altering the TRP in the iterative plan application and testing procedure, generates new capacities of reinforcement that adhere to new power flow conditions of the line ($PFC_{LINE}$). The plan application and testing process is stopped if the pre-defined number of attempts (an input to the framework, determined empirically) for locating a successful plan under the most onerous power flow condition has been reached or an error has been flagged.

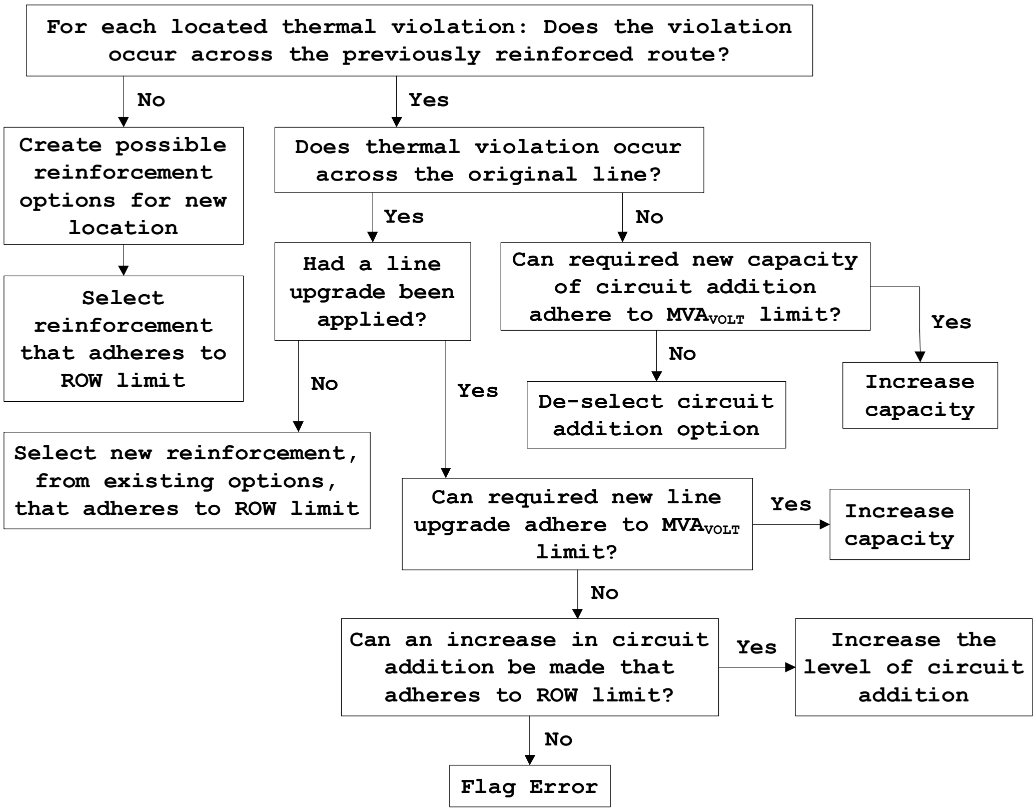


**Figure 4-5 Flowchart of the systematic method used to alter a reinforcement plan**

An error can be flagged if the thermal violation discovered exists on the original line (i.e. does not exist on the added circuits) and an upgrade, through reconductoring of the existing single-circuit or double-circuit line, cannot be achieved without breaching the $MVA_{VOLT}$ constraint despite the application of the maximum level of circuit addition (constrained by the ROW limit). If the plan application and testing process is stopped, a new $PFC_{MAX}$ is selected for the population individual and a new plan is generated; the previous failed TRP is removed.

Once a successful reinforcement plan has been produced, the annual constraint cost saving of the plan is assessed. Only if a saving is calculated does the plan get evaluated against the remaining objectives and included in the initial population. If however the reinforcement plan is deemed to exacerbate network congestion, in comparison to the base case network, and cause a negative saving in annual constraint costs then the process is bought back to the initial plan, designed for the chosen $PFC_{MAX}$, and the plan application, testing and alteration methods are repeated. A pre-defined number of attempts (an input to the framework, determined empirically) are allowed at altering the initial plan to achieve a constraint cost saving, before removing the failed plan design and creating a new plan in its place, designed for a new

$PFC_{MAX}$. This part of the process is also designed to maintain, as far as possible, the initial characteristics of the plan.

The methods employed in the MOTREP framework allow for the creation of unique reinforcement solutions for each line with a thermal limit violation, and the generation of a unique plan for varying conditions of maximum power flow condition, creating a large search space for the SPEA2 to explore. The initial population of solutions leads to the exploration of:

a) **Reinforcement solutions in different areas of the network** – through altering $PFC_{MAX}$ and from creating solutions (using the method for altering a TRP) to solve exacerbated thermal related network issues in other network areas that have been caused by the original reinforcement solution;
b) **Different configurations of reinforcement solutions that adhere to the ROW constraint** – through the addition of line upgrading (through reconductoring) as an option to line addition (considered as the only option in the meta-heuristic multi-objective transmission planning models reviewed in Chapter 2) and secondly to the treatment of single-circuit and double-circuit configurations as separate reinforcement alternatives; and
c) **Varying capacity limits of reinforcement solutions** – through selecting varying values of $PFC_{LINE}$ between the limits of $PFC_{LINE}^{Min}$ and $PFC_{LINE}^{Max}$. This aspect was also not a consideration in the meta-heuristic multi-objective transmission planning models reviewed in Chapter 2.

The exploration of these aspects, using the SPEA2, will lead to the creation of plans that have a favourable result in at least one of the transmission planning objectives chosen. By including variations in reinforcement location, configuration and line capacity, interesting trade-offs are likely to be discovered that reflect the reality of the transmission planning problem. For example; annual levels of network congestion could be further alleviated across a line that has been reinforced (causing a saving in constraint costs) if the capacity of the reinforcement solution is increased. However, this comes at an increased capital investment cost that might negate the economic benefits of the reinforcement.

Currently, to restrict the size of the search space, the more expensive investment options of upgrading existing lines to a higher voltage level or adding lines at a new voltage level, have been excluded. These options could be included in the proposed framework by altering $MVA_{VOLT}$ in (4-4), and adding further cost coefficients to the capital investment cost objective to consider the addition of network transformers or any other associated substation works. Chapter 6 details how additional options for network reinforcement can be included to extend and improve the proposed framework.

# 4.7. *Range of Objectives Analysed*

## 4.7.1. Capital Investment Cost

The capital investment cost objective evaluates the upfront costs required to implement the TRP. Suitable capital cost coefficients in £/MVA.km and £/km are used for OHLs and UGCs respectively to determine the upfront cost for the route length and line capacity of each reinforcement solution in the plan. The capital investment cost of a TRP is calculated as:

$$IC_{TRP} = \sum_{k \epsilon TRP} \left( C_{ijk}^{SC} SC_{ijk} + C_{ijk}^{DC} DC_{ijk} + C_{ijk}^{UPG} UPG_{ijk} \right) \tag{4-6}$$

where $IC_{TRP}$ is the investment cost of the plan; $C_{ijk}^{SC}$, $C_{ijk}^{DC}$ and $C_{ijk}^{UPG}$ are the cost of the proposed single-circuit addition, double-circuit addition and line upgrade respectively for the $k$th line in the plan, along the route *i-j*; $SC_{ijk}$, $DC_{ijk}$ and $UPG_{ijk}$ are the single-circuit, double-circuit and upgrade binary variables from the decision vector (1 = select, 0 = deselect), that adhere to the ROW constraint for the $k$th line in the plan, along the route *i-j*.

For composite line constructions that are part OHL and part UGC, each section is treated separately to consider the different estimations of reinforcement cost for each type. Reconductoring is assumed to only apply to OHLs – upgrading a UGC would involve excavating the original conductors at a cost more comparable to the original cost of installing

**Table 4-2 Cost coefficients for calculating capital investment cost [4.32]-[4.33]**

| Circuit Type | Cost |
|---|---|
| OHL Single-circuit addition | £814/MVA.km |
| OHL Double-circuit addition | £368/MVA.km |
| OHL Single-circuit upgrade | £397/MVA.km |
| OHL Double-circuit upgrade | £175/MVA.km |
| UGC Single-circuit addition | £5.9million/km |
| UGC Double-circuit addition | £7.2million/km |
| OHL Upgrade adjustment factor | -£0.28/km |

the cable. Thus, if an upgrade is applied to a composite line in a TRP, the total capital cost of the reinforcement is calculated as the cost resulting from reconductoring the OHL, and for addition of a single-circuit or double-circuit to the UGC that corresponds to the original circuit construction. Hence in this case the cost coefficients for line addition to a UGC are used as line re-building costs.

For the case studies analysed in this thesis the cost coefficients detailed in Table 4-2 are used. These coefficients were calculated from a 2009 report into the options and potential costs for the Beauly – Denny OHL reinforcement [4.32] and a 2010 transmission project appraisal report prepared by Parsons Brinckerhoff (requested by Ofgem) which critiqued, among other objectives, the forecast capital expenditure of network reinforcements nominated by TNOs for funding under the Ofgem Transmission Access Review [4.33]. For upgrading OHLs, there was a distinct trend found in [4.33] between distance and cost for the £/MVA.km cost coefficient. Hence an upgrade adjustment factor (as detailed in Table 4-2) is used to adjust the OHL upgrade coefficients (single-circuit and double-circuit) for the required reinforcement route length, before using the adjusted coefficient in the calculation of $IC_{TRP}$.

The installation cost of UGCs compared to OHLs is significantly greater. Scott [4.32] states that the installation costs of UGCs, at high voltage levels, are generally between 4 and 10 times that for OHLs. Hence, it is important to separate these coefficients in the calculation of $IC_{TRP}$. The coefficients used for UGC installation were calculated from [4.33] and equate to an installation cost 4.5 times that of an OHL.

### 4.7.2. Annual Line Loss Saving and Incremental O&M Cost

The annual line loss saving objective evaluates the saved $I^2R$ resistive heating losses as a result of the TRP. As previously mentioned, the modelling framework uses a DCPF to model the network under study. The active power magnitude across the line is therefore assumed to be equal to the current magnitude across the line; hence, the annual line loss saving of a network is simply calculated using the following formulation:

$$LL_{SAV}^{YEAR} = \left[5000\times\left(LL_{SAV}^{PK-NEW} - LL_{SAV}^{PK-ORIG}\right)\right] + 2.3 \qquad \text{(4-7a)}$$

$$LL_{SAV}^{PK} = \sum_{k}\left({P_{ijk}}^{2}R_{ijk}\right)\times S_{base} \qquad \text{(4-7b)}$$

where $LL_{SAV}^{YEAR}$ is the annual TWh network line loss saved; $LL_{SAV}^{PK}$ is the TW line loss of a network at ACS peak demand of which $LL_{SAV}^{PK-NEW}$ and $LL_{SAV}^{PK-ORIG}$ represent the line loss of the new network (including the TRP) and the base case network respectively; $P_{ijk}$ is the per unit active power flowing in the $k$th transmission line from $i$-$j$; $R_{ijk}$ is the per unit resistance of the $k$th transmission line from $i$-$j$, and $S_{base}$ is the system MVA base.

Equation (4-7a) for calculating $LL_{SAV}^{YEAR}$ is based on the formula in [4.34]. According to the study by the Electricity Networks Strategy Group [4.34], this formula calibrated with GB network studies in 2009. It is assumed that this formula remains adequate for the case studies analysed in this thesis. The gradient and intercept of the trend for $LL_{SAV}^{YEAR}$ are inputs to the framework and can therefore be altered for the network under study.

One way to reduce the resistive heating losses of a line is to increase the voltage level, causing a reduction in current flow to maintain the same power flow. As a DCPF is currently used, and the reinforcement options available exclude the upgrading of a line to a higher voltage level, line loss saving is mainly achieved through single-circuit and double-circuit addition. The effect of adding a new line, with the same line parameters, to an existing line, halves $P_{ijk}$ and maintains $R_{ijk}$ in each line. Thus, a trade-off exists between the increased capital costs of line addition, in comparison to line upgrading, and the resultant increase in line loss saving.

This trade-off is further complicated by the effect of line addition on the annual incremental O&M cost of a TRP, $OM_{TRP}$. This is the cost associated with maintenance on newly added UGCs and OHLs to the base case network. For OHLs this cost covers added route patrols, inspections, vegetation management and tower painting. Hence line addition increases the annual incremental O&M cost of a reinforcement plan. $OM_{TRP}$ is simply assessed using £/circuit-km coefficients on each line addition within the TRP; a separate coefficient can be applied for each voltage level in the transmission network.

For the case studies analysed in this thesis, coefficients of £767/circuit-km and £2398/circuit-km are used for all newly connected OHLs and UGCs respectively. These coefficients are the average of the O&M costs detailed in [4.35] – a report on the comparative costs of new electricity infrastructure, which National Grid found to be broadly in line with their own analysis [4.36] – for a range of varying capacities and route lengths of 400kV AC OHLs and

UGCs. Due to a lack of publicly available information on the O&M costs of transmission lines, these coefficients (derived for the 400kV network) are used in the case studies for line addition at all voltage levels of the GB transmission network.

### 4.7.3. Outage Costs

The outage cost objective evaluates the costs associated with planned outages of transmission lines to accommodate the construction of the reinforcement plan. These planned outages usually occur in the summer when network demand is at a minimum. This ensures reduced disruption to power stations, which also have a planned outage programme during low demand periods in the summer when wholesale electricity prices are normally at their lowest. The costs associated with planned network outages result from compensation payments made by the TNO to any generating units with firm access rights that have been temporarily disconnected from the network, or have had to reduce their output because of the outage. The affected generating units are compensated by the greater of either a system wide average TNUoS charge, or the site TNUoS charge paid by the unit, for the outage duration [4.37]. The planned outage cost of a reinforcement plan is calculated by splitting the plan into outage groups. An outage group is a group of lines in the plan that are to be excluded from the base case network at the same time. Currently, the desired number of outage groups is created in the framework by splitting the reinforcement plan equally.

The number of outage groups used in the calculation of outage cost is an input to the framework and should reflect the extent of network reinforcement which is required by the plan and can be realistically achieved on an annual basis. As each TRP generated in the initial population consists of a different number of network reinforcements, due to the variation of $PFC_{MAX}$, the number of outage groups would need to be varied for different sizes of reinforcement plan. Further there are trade-offs in determining the number of outage groups. Firstly, the more outage groups assessed the greater the computational effort required for assessing the outage cost of a TRP, and the more reduced the computational effort required for assessing the annual constraint cost saving of a plan (see section 4.7.4.) would need to be to maintain the overall simulation time of the framework. Secondly, reducing the number of outage groups for a plan too far can cause electrical islanding of the base case network. If electrical islanding in the network occurs then the total generation of each island must be greater than or equal to the load of the island for a DCPF to run successfully; as this cannot always be guaranteed in the network under study, electrical islanding needs to be avoided.

To satisfy the above trade-offs and estimate within reason the extent of annual reinforcement able to be achieved, a general rule has been used in the case studies to determine the number of outage groups for all generated reinforcement plans. This is that the number of outage groups used is equal to two per annum between the year of the base case network and the year of the scenario. Hence for a case study involving the application of a scenario for the year 2020 to a base case network from the year 2014, the number of outage groups used to accommodate the construction of a reinforcement plan is 10. This rule has been found to be successful for the case studies in this thesis. Appendix A.2. details the effect of altering the number of outage groups in the simulation time and evaluation result of a TRP's outage cost. This brings clarity on the aforementioned trade-off in determining the number of outage groups and concludes the success of the utilised rule.

Figure 4-6 details the method used for calculating the outage cost associated with a reinforcement plan. The construction of a reinforcement plan will take place during the summer season between the base case network year and the scenario year. A median case study based summer minimum demand value is used to represent the demand trend expected between the base case year and scenario year. Hence any increase or decrease in summer minimum demand during the construction of the plan is considered.

The average median summer demand is attributed to each network node using the method detailed in section 4.3.1. Contributory generating units from a generation mix for the year of the base case network (see section 4.2.) are then identified for the median summer minimum demand value using the method detailed in section 4.5.1. However, for this application the plant margin is calculated by replacing the assumed ACS peak demand value of the scenario with the value for summer minimum demand in (4-2). Further, generation capacity from wind, tidal and wave energy sources are de-rated for the calculation of plant margin, to match the expected availability of the source during the summer seasons between the base case network year and the scenario year (as opposed to de-rating the capacity to match the expected source availabilities at ACS peak demand). The contributory generating units are then determined by means of a generator type ranking order that reflects the likely operation of these units during the summer seasons between the base case network year and the scenario year.

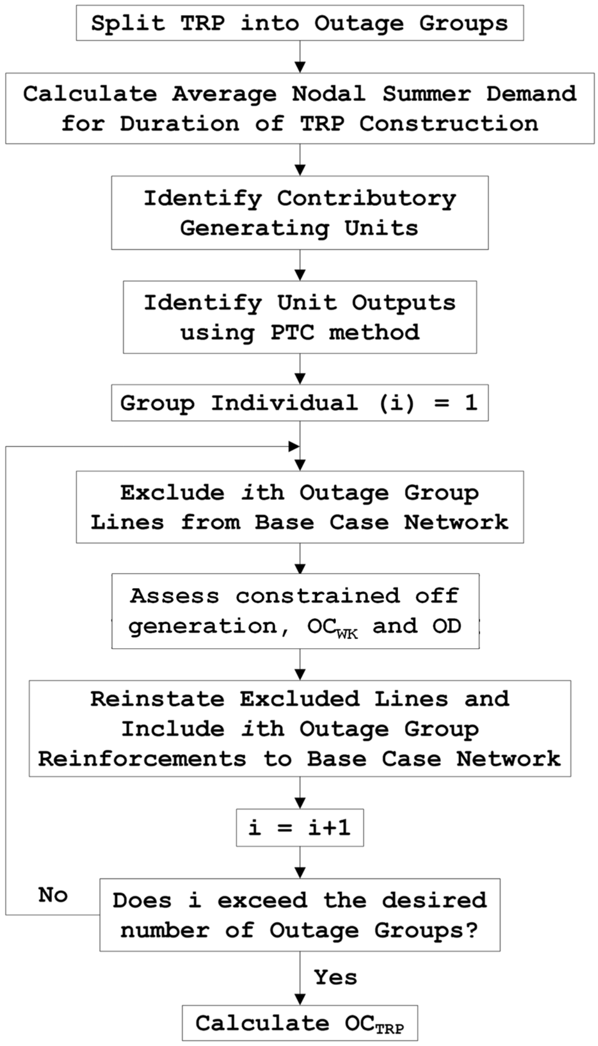


**Figure 4-6 Flowchart of the method used for assessing outage cost**

Generating unit outputs are then set for the demand level using an adapted version of the EPTC method (see section 4.5.2). For this adapted version, the only generating unit types which are directly scaled in the EPTC method are wind (onshore and offshore), wave and tidal units, leaving all other generating units to be scaled down using the economy scaling factor. These units are directly scaled using availability parameters that reflect their predicted operation across the summer season. Hence the planned transfer condition (PTC) applied here excludes the economy criterion of the EPTC method and is applied to model the likely output of generation during the summer season.

Following the determination of expected generating unit outputs using the PTC method, constrained off generation, per week outage cost ($OC_{WK}$) and outage duration ($OD$) is assessed for each outage group using a DCOPF. The assessment involves excluding transmission lines from the base case intact network that are associated with the outage group (by changing the status of the lines within the branch data matrix from in-service to out-of-service), running a DCOPF on the intact and non-intact network to calculate constrained off generation, reinstating the lines and including the reinforcements associated with the outage group to the base case network; thereby including the effect on constrained off generation of a previous outage group's network reinforcement.

Figure 4-7 details the method used for determining constrained off generation as a result of each outage group. The base case for constrained off generation from the intact network is first determined. The intact network could (although rarely) include thermal overloads due to the outputs defined for contributory generating units and the assumed nodal minimum demand of the case study. A DCPF, using summer line ratings from the branch data matrix, is thus run to check for thermal overloads. If overloads exist in the intact network, then a DCOPF (again using summer line ratings) is run to obtain the base case for constrained off generation (a DCPF requires less simulation time than a DCOPF). This base case is compared to the constrained off generation determined from running a DCOPF on the non-intact network. Any increase in constrained off generation from the intact network is used in the calculation of outage cost. As reinforcements are added from the outage group to the intact network, which may exacerbate thermal constraints, a new base case assessment on constrained off generation, due to the new intact network, is required to define the effect of the next outage group. Hence for each outage group, potentially two DCOPF simulations are necessary.

To implement a DCOPF for the outage cost objective, piecewise linear cost functions are used for each generating unit in the cost data input matrix. Figure 4-8 details the form of the piecewise linear cost function $f(p)$ applied to each generating unit, where $p$ is the power capacity in MW of each generating unit and $f(p)$ is the cost of each generating unit defined by the coordinates $(p_0, f_0)$, $(p_1, f_1)$, …, $(p_n, f_n)$, where $p_0 < p_1 < \cdots < p_n$ and $f$ is the cost in £/hr. Three coordinates are used in the cost function. The first two coordinates are crucial in determining constrained off generation across the network, and as such a general cost (in this case £100/hr) can simply be applied to the remaining capacity (i.e. the unused TEC) of all contributory generating units for the DCOPF to calculate the required increase in generation output.

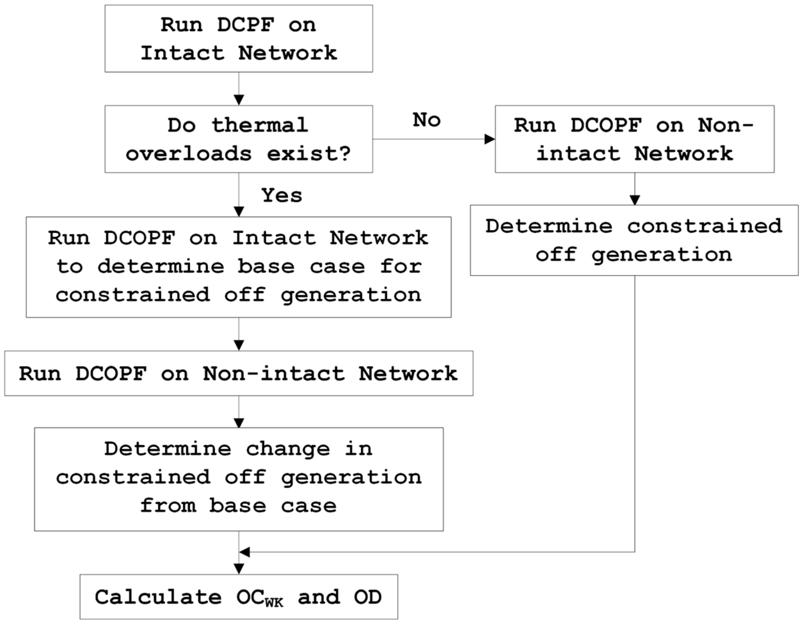


**Figure 4-7 Flowchart of the method used for determining constrained off generation in the assessment of outage cost**

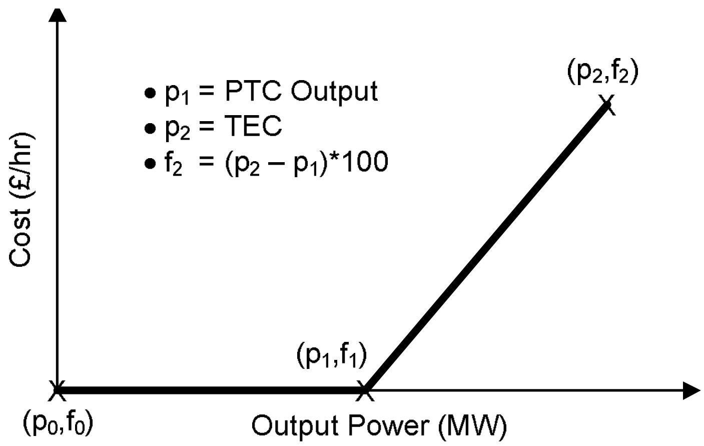


**Figure 4-8 Piecewise linear cost function used to estimate outage cost**

The assessment of a plan's outage cost can be formulated as follows:

$$OC_{TRP} = \sum_{i} (OC_{WKi} \times OD_i) \quad (4\text{-}8a)$$

where

$$OC_{WKi} = \sum_{j} \left(COf_j \times TNUoS_{WKj}\right) \quad (4\text{-}8b)$$

and $OC_{TRP}$ is the total outage cost of the TRP; $OC_{WKi}$ and $OD_i$ is the outage cost per week and the outage duration for the $i$th outage group respectively; $COf_j$ is the MW constrained off output, determined using a DCOPF, of the $j$th generating unit caused by an outage from the base case network of the original lines associated with the $i$th outage group, and $TNUoS_{WKj}$ is the equivalent per week compensation for the $j$th generating unit (calculated based on the greater of the system wide average TNUoS charges or the zonal site TNUoS charge).

For the GB transmission network, locational TNUoS tariffs are applied across a number of generation zones. Each generating unit is allocated to a generation zone based on where it is electrically connected. Thus, to calculate $TNUoS_{WKj}$, each network node needs to be allocated a generation zone. For the case studies in this thesis, data on generation zones was obtained from [4.20]. In calculating $OD_i$ it is assumed for the case studies that line upgrading can be achieved at a rate of 3.9 circuit-km/week (calculated from [4.34]) and 0.15 circuit-km/week (calculated from [4.38]) for OHL and UGC sections respectively. Hence a double-circuit OHL section would be assumed to be upgraded at a rate of 1.95km/week. These rates for line upgrading are inputs to the MOTREP framework and can therefore be altered. For line addition (single-circuit or double-circuit), as opposed to line reconductoring, it has been assumed for the case studies that an outage of only one week is required (due to the assumption that work involving line addition can be carried out adjacent to the existing line); this outage assumption for line addition is also an input to the framework.

Several simplifications to assess a plans total outage cost have been required to be made as a result of the increased computational effort put towards assessing annual constraint cost saving (see section 4.7.4.). Nodal summer demand, through the use of a median summer minimum demand value, is assumed to remain constant across the outage duration and for all outage groups. Hence constrained off generation is currently assessed statically, avoiding a more temporal assessment of $OC_{WKi}$ and therefore $OC_{TRP}$. Further, average zonal TNUoS tariffs are used to represent the charges applied during the period from the base case network year to the scenario year and are thus assumed to remain constant; TNUoS tariffs for some zones can vary significantly from year to year, as is shown by the comparison in [4.39] of tariffs for 2012/13 and 2011/12. Thus, recalculating average zonal tariffs on an annual basis for new generation expansion plans and demand levels (as explored by Ault *et al.* [4.40]) is outside the scope of this research. Finally, by optimising the size, timing and order of outage groups required to

**Table 4-3 Wider zonal TNUoS tariffs used to estimate outage cost (source [4.39])**

| Generation Zone | Zone Name | Wider Zonal Tariff (£/kW) |
|---|---|---|
| 1 | North Scotland | 21.96 |
| 2 | Peterhead | 20.11 |
| 3 | Western Highlands & Skye | 22.05 |
| 4 | Central Highlands | 17.56 |
| 5 | Argyll | 14.19 |
| 6 | Stirlingshire | 14.23 |
| 7 | South Scotland | 12.79 |
| 8 | Auchencrosh | 10.50 |
| 9 | Humber, Lancashire | 6.08 |
| 10 | North East England | 8.43 |
| 11 | Anglesey | 7.10 |
| 12 | Dinorwig | 6.36 |
| 13 | South Yorks & North Wales | 4.61 |
| 14 | Midlands | 2.39 |
| 15 | South Wales & Gloucester | 2.03 |
| 16 | Central London | -13.35 |
| 17 | South East | 2.32 |
| 18 | Oxon & South Coast | -1.11 |
| 19 | Wessex | -1.71 |
| 20 | Peninsula | -5.68 |

accommodate the construction of the reinforcement plan, constrained off generation can be minimised and the outage cost of the reinforcement plan can be reduced. However, a separate time consuming optimisation would then be required for every TRP generated.

As the prediction of average zonal TNUoS tariffs between the year of the base case network and the scenario year is outside the scope of this research, the zonal tariffs for 2012/13 (detailed in Table 4-3 and obtained from [4.39]), resulting in a system wide average TNUoS charge of £7.54/kw, are used for each case study analysed. It is not unusual for zonal tariffs to be negative in areas of high demand; this is to wholly encourage the location of generation near to demand. For generating units located in these zones (amongst other areas below £7.54/kW), $TNUoS_{WKj}$ is calculated based on the system wide average TNUoS charge.

### 4.7.4. Annual Constraint Cost Saving

The maximisation of annual constraint cost saving is one of the leading objectives of electrical transmission planning due to the extent of the annual economic savings that can often be achieved from alleviating network congestion. Hence, due to the economic impact of this objective, a more significant computational effort is placed on this objective in comparison to other planning criteria for the case studies analysed in this thesis. The framework carries out an improved temporal assessment of annual constraints in comparison to many other multi-objective meta-heuristic transmission planning models (see Chapter 2) and scenario evaluation tools (see Chapter 3). To calculate the scenario-related annual constraint cost saving of a generated TRP, the annual constraint cost of the plan must be calculated for the scenario year and subtracted from the annual constraint cost calculated for the unexpanded and unreinforced base case network.

The annual constraint cost of a plan is assessed using a method similar to the method employed in 2008 by the NETS SQSS review group [4.41], however, the method used here explicitly models network constraints and includes a generation dispatch optimisation to reduce the associated cost from the Balancing Mechanism (BM). The explicit modelling of constraints is also a benefit in comparison to the current SO CBA assessment for the NOA process (see Chapter 2). The method employed by the framework can select the minimum system wide constraint cost combination of offers and bids when constraining generating units on or off.

Bid and offer pricing is part of the BM under which a SO will pay a generator unit an offer price to increase its output, or receive a bid price payment from the generator unit to reduce its output. A typical constraint action carried out previously in studies by the GB SO involved constraining off a base load CCGT plant in Scotland, at a bid price of £10/MWh; and constraining on marginal gas plants in England, at an offer price of £100/MWh, giving a constraint price to the SO of £90/MWh [4.34].

As the BM for a half-hour settlement period opens one hour before the start of the period (known as the Gate Closure) in the UK under the British Electricity Trading and Transmission Arrangements (BETTA) [4.42], the offers and bids from transmission connected generator units, submitted to the SO, can vary significantly on an hourly basis. To simplify the assessment of the future annual operation of the BM, predictions on a fuel type's average annual bid and offer price can be made. These predictions can be scenario-related and depend upon the operation and therefore financial situation (i.e. related in part to security of fuel supply) of the generating units associated with each fuel type. Predicting a fuel type's average future bid and offer price for the scenario to be assessed is outside the scope of this thesis. Hence, the fuel type offer and bid prices detailed in Table 4-4 are used for each case study analysed.

**Table 4-4 Plant Type Bid and Offer Prices (source [4.34])**

| Generator Type | Bid Price (£/MWh) | Offer Price (£/MWh) |
|---|---|---|
| Nuclear | -100 | n/a |
| Wind/Wave/Tidal/Biomass/CHP | -50 | n/a |
| Base load CCGT (±CCS) | 10 | 40 |
| Base load Coal (±CCS) | 15 | 60 |
| French Interconnector | 20 | 80 |
| Hydro | 23 | 90 |
| Marginal Gas (CCGT/OCGT) | 25 | 100 |
| Marginal Coal | 30 | 120 |
| Pumped Storage | 75 | 300 |
| Other Interconnector | 90 | 360 |

The offers and bids in Table 4-4 represent the average prices that National Grid experienced over 2005-2007 as SO across the broad operation of the BM. These prices were used for analysis of year 2020 of the 2009 Gone Green scenario [4.34]. The highly negative plant type bid prices for nuclear, wind, wave, tidal and biomass generating units, as well as CHP schemes, signifies that these plant types will not offer the SO the option to be constrained off cheaply. This is because of commercial and operational considerations. Further, it is highly unlikely that these plant types will ever be constrained on and so no offer prices are allocated.

To calculate the constraint cost of a network, a load duration curve (LDC) for winter and summer updated for the scenario year is used. An LDC details the variation of demand level as a percentage of peak demand, from highest to lowest. The horizontal axis of the LDC details the percentage of time that each demand level is exceeded during the year. The GB LDC for 2011 [4.43] was used as the basis to model future years of the case studies analysed in this thesis. The chosen LDC is obtained from demand values on a 30-minute time step that include transmission losses and exclude power station demand, pumping from pumped storage and interconnector exports; matching the characteristics of the scenario related unrestricted ACS peak demand value.

A summer outage season is included in this objective assessment to account for planned outages - needed to carry out maintenance work on network assets - that regularly occur during the lowest demand period of the summer season. The LDC for the summer outage season is obtained in the MOTREP framework from the last section of the summer LDC. The inclusion of a summer outage season is a requirement to assess more accurately the annual constraint cost saving of a transmission plan. A suitable assumption for the length of a UK summer outage season is around 8 weeks [4.41]. A duration double in length to this would suggest major refurbishment or reinforcement, which might be taking place over a five-year period

[4.41]. The duration of the summer outage season is an input to the MOTREP framework. For the case studies analysed in this thesis the duration has been set to 8 weeks. Using a duration of 8 weeks reduces the summer season LDC down to 23 weeks (the winter season LDC is 21 weeks from November to March). Appendix A.3. details the effect of altering the length of the summer outage season (8 or 16 weeks) in the evaluation of annual network congestion.

The method used by the GB SO [4.41] for assessing annual constraint cost saving splits the GB transmission network into only four 'wider' system boundaries and therefore five areas, as opposed to the standard boundary model used by the GB TNO and SO to analyse the NETS (see Chapter 2). These 'wider' boundaries split the NETS into five areas that can be defined as SHE-T North West, SHE-T North East, SHE-T South and SPT, Upper North (see Figure 1-1) and the rest of mainland UK (RUK). For the summer outage season, to simulate current maintenance requirements in the GB NETS, an outage of two of the most significant (i.e. highest line capacity) single circuit lines or a double-circuit line for each boundary was accounted for and excluded from the transmission network [4.41].

The modelling framework of this thesis utilises an input array denoting the chosen lines to be allocated an out-of-service status in the branch data input matrix for the base case transmission network during the summer outage season. The lines to be excluded can therefore be altered for the network under study. For the case studies analysed in this thesis the chosen lines to be excluded are fixed and match the outage conditions defined above. These are as follows:

- Part of the Beauly – Denny OHL (**crosses boundary 1 between SHE-T NW and SHE-T NE**): double-circuit exclusion from Fort Augustus to Errochty (~70km section of the 220km line). The circuits operate at 400kV and 275kV and the line capacity is ~4500MVA.
- Single-circuit 275kV OHL from Kintore to Tealing (**crosses boundary 2 between SHE-T NW/NE and SHE-T South & SPT**): ~90km line with a line capacity of ~880MVA.
- Single-circuit 275kV OHL from South of Kintore to Kincardine Bridge (**crosses boundary 2**): ~150km line with a line capacity of ~890MVA.
- Double-circuit 400kV OHL from near Eccles to Stella West (**crosses boundary 6 between SHE-T South & SPT and Upper North**): ~90km line with a line capacity of ~3070MVA.

- Double-circuit 400kV composite line from Lackenby to Thornton (**crosses boundary 7 between Upper North and RUK**): ~100km line with a line capacity of 2420MVA.

Each seasonal LDC is split into a pre-defined number of demand blocks of varying duration, using the rectangular rule to capture its shape whilst ensuring that each rectangle crosses the seasonal LDC at the midpoint. Figure 4-9 illustrates this method and details the seasonal LDCs used for the case studies; 8 demand blocks were chosen. The resulting levels of demand are used along with stochastic generator unit output assumptions to assess annual congestion levels for the scenario year, and the resultant cost.

For each generator type, a suitable probability distribution is created around an expected mean availability (different in winter and summer) and used to determine the output of all generating units for each simulation of network congestion. This is the method used in the framework to estimate the initial output of generation from the 'bilateral' market (agreed days, weeks or months in advance) before the BM. Table 4-5 details the probability distributions used for each generator type and for each case study and the availabilities assumed to generate the required stochastic output assumptions for supply. Most generator types have a lower availability in the summer than in the winter; reflecting a typical generation outage program. The availability of

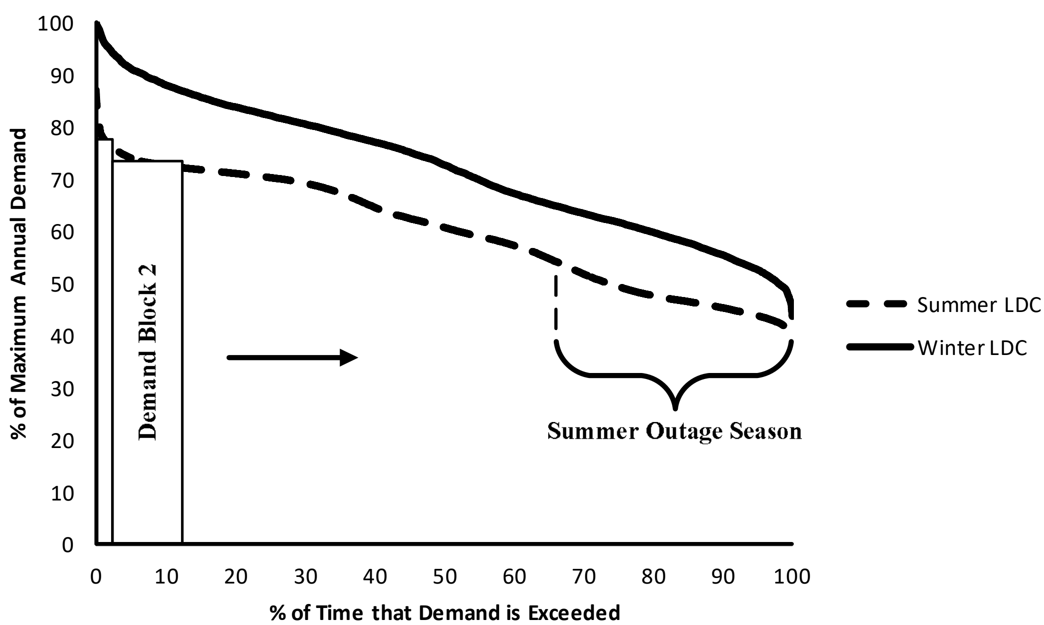


**Figure 4-9 GB 2011 LDC split into summer (Apr-Oct) and winter (Nov-Mar) seasons including an illustration of the method used for LDC estimation**

**Table 4-5 Generator Type Distributions and Availabilities (source [4.41])**

| Generator Type | Distribution | Winter Mean (%) | Summer Mean (%) |
|---|---|---|---|
| Wind (Onshore; Offshore) | Triangular | 35; 40 | 35; 40 |
| Nuclear | Binomial | 80 | 70 |
| Wave; Tidal | Binomial | 30; 35 | 30; 35 |
| Base load CCGT (±CCS) | Binomial | 90 | 85 |
| Base load Coal (±CCS) | Binomial | 85 | 75 |
| Hydro (LDC block 1-4; 5-8) | Normal | 60; 10 | 60; 5 |
| Marginal Gas (CCGT/OCGT) | Binomial | 90 | 85 |
| Marginal Coal | Binomial | 85 | 75 |
| CHP | Binomial | 83 | 78 |
| Biomass | Binomial | 80 | 75 |
| Pumped Storage (1-4; 5-8) | Binomial | 90; 25 | 90; 15 |

generation from pumped storage and hydro schemes is reduced in low demand blocks in the winter season (i.e. in this case blocks 5-8) and across the summer outage season, simulating the expected operation of these generator types as they are most likely to run at high demand levels.

The output of most generator types is obtained using a binomial distribution, which requires two parameters; the number of trials and the probability of success on each trial. The former is the number of generating units for each type that are expected to connect to the network, and the latter is the seasonal availability of that generator type. The availability of generation from hydro schemes is obtained using a normal distribution, with a mean parameter equal to the seasonal availability and a standard deviation of 4% [4.41]. Further, the availability of generation from wind (both onshore and offshore) is obtained using a triangular distribution.

A triangular distribution is used to capture the fast rise in probability for availabilities less than the distribution mode and the long tail after the mode (reflecting a slower fall in probability) that is expected for onshore and offshore wind generating units [4.41]. The minimum and maximum availability in the distribution, assumed for both onshore and offshore wind units, is 5% and 80% respectively [4.41]. As the mean, minimum and maximum availability of the associated generating unit type are inputs to the framework, the mode of the distribution is calculated by means of the formulation below:

$$c = (\bar{T} \times 3) - a - b \tag{4-9}$$

where $\bar{T}$ is the mean of the triangular distribution, $T$, and $a$, $b$ and $c$ are the lower limit, upper limit and mode of $T$.

Using a mean of 35% (and a min and max of 5% and 80% respectively) for generation from onshore wind gives a distribution mode of 20%. For generation from offshore wind, a greater mean of 40% is used to reflect the increased output expected from higher wind speeds; this results in a distribution mode of 35%. Figure 4-10 illustrates the triangular distribution used to derive the availability of onshore wind generating units. A generating unit's availability ($A$), given a random variate ($U$) drawn from a uniform distribution in the interval (0, 1), is obtained from the triangular distribution using the following:

$$A = \begin{cases} a + \sqrt{U(b-a)(c-a)} & \text{for } 0 < U < F(c) \\ b - \sqrt{(1-U)(b-a)(b-c)} & \text{for } F(c) \leq U < 1 \end{cases} \qquad (4\text{-}10a)$$

where

$$F(c) = (c-a)/(b-a) \qquad (4\text{-}10b)$$

For all generating units connected to the network except wind units, a separate availability is used from the chosen distribution (for each simulation of network congestion) to determine a unique output for each unit. For wind generating units (onshore and offshore), an availability is assumed (for each simulation of network congestion) for all wind farms within identified zones of the transmission network. The zones used to split the network are the generation zones used to apply TNUoS charges for the assessment of outage cost (see section 4.7.3.). This

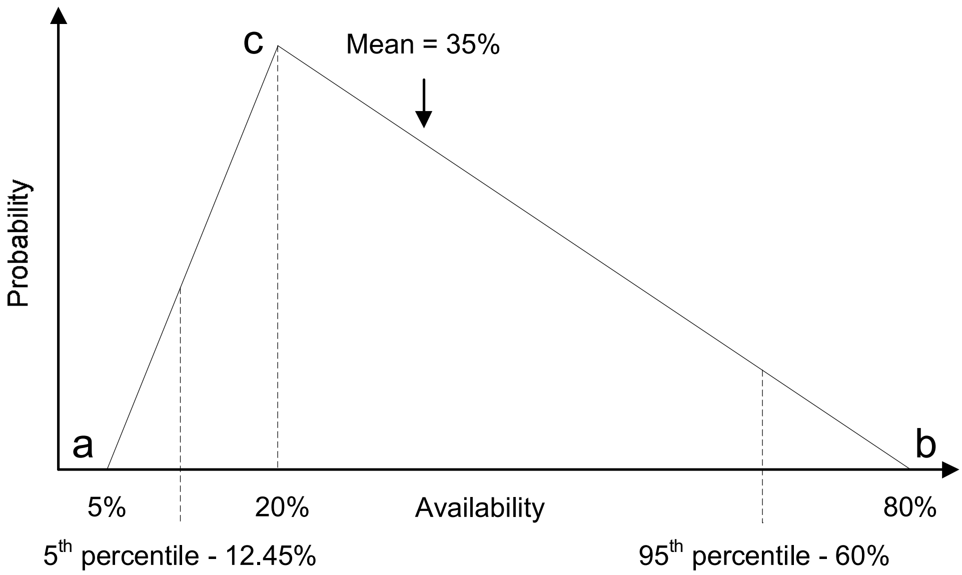


**Figure 4-10 Illustration of the triangular distribution used to derive the availability of onshore wind generation**

is for correlating the output of wind generation – a requirement as the speed and strength of wind acts over a wide area.

The correlations between 2080 pairs of onshore wind farm sites in the UK, as a function of the distance between the sites, was analysed by Sinden [4.44]. The correlation between wind farm outputs at different sites was found to decrease with increasing distance between the sites. Distances (in km) between the central points of each generation zone are used by the framework. By using an estimation of the trend detailed in Figure 5 of Sindens' work [4.44], these distances are converted into wind farm output correlations between each zone – the power output of wind farms within the same zone is assumed to be 100% correlated. The distances assumed and the resulting correlations calculated, using this trend, between each zone in the GB transmission network are detailed in Appendix B. These correlations, although defined for onshore wind units, are also used for offshore wind farm sites. These sites are allocated a generation zone based on the likely location of their onshore network connection.

As a minimum requirement, the availabilities obtained from the triangular distribution for wind generating units should adhere to correlations between nearby zones. For each zone that contains a wind farm, availabilities (for each simulation of network congestion) are obtained in batches of ten from the triangular distribution. In order of lowest to highest zone (i.e. from the north of Scotland down to the south of England) which contains a wind farm for the scenario, the array of availabilities from this batch is then compared between each zone and the next higher numbered zone (i.e. not necessarily neighbouring). If the linear correlation coefficient between either array is not equal to the correlation required between either zone (up to 2 decimal places) then a new batch of availabilities is obtained from the triangular distribution.

Once the required correlation between zonal availabilities has been reached then the process moves on through the zonal order. For example, if wind farms are in generation zones 1, 6 and 14, then according to correlations assumed in Appendix B, the overall output in zone 6 will be 65% correlated to the output in zone 1, and the overall output in zone 14 will be 38% correlated to the output in zone 6. However, there is no attempt made in the framework at ensuring that the overall output of zone 14 will be 26% correlated to the output in zone 1. This process of obtaining a correlated generation availability is repeated until all nearby zonal correlations have been accounted for and enough availability information is obtained to carry out all required simulations of network congestion. This process is required to be carried out in batches within the framework as the computational effort needed to satisfy the zonal correlations for larger arrays was found to be too extensive.

The generator unit output assumptions from the probability distributions chosen are used along with the varying levels of demand (obtained from using the rectangular rule to capture the shape of the seasonal LDC) to assess at numerous points the scenario related network congestion. For each simulation of network congestion in each demand block, the import and export contribution from all interconnectors is calculated using the method in section 4.5.1., except regarding the case studies in this thesis, the links to Ireland where full export is assumed. Export contributions are added, at the specified network locations, to nodal demand and the total import contribution from all interconnectors is then subtracted from total demand to obtain a new value of network demand.

If generation exceeds demand, then by using a scenario related seasonal generator type ranking order, the output of the smallest unit of the lowest ranked generator type is set to zero until generation can be made to match demand by altering the output of the next to be removed unit. If however supply does not exceed the new demand value, then a new set of generator unit output assumptions are derived from the probability distributions. For each simulation of network congestion, a pre-defined number of attempts (an input to the framework, determined empirically) are allowed to locate a generation output to match demand before flagging an error and judging the scenario not to be supply secure.

Once generation matches demand, import contributions from the interconnectors are added (at the specified network locations) to the list of identified contributory generating units and a piecewise linear cost curve is then derived for each generating unit and interconnector (deemed to be importing), by allocating no cost for the initial output of the unit/interconnector and applying a cost equal to the unit/interconnector offer price, to the remaining unused unit/interconnector TEC. This creates the required situation where the DCOPF must calculate constrained off generation and interconnector imports, due to thermal constraint issues only, as well as determine the optimal allocation of increased generator unit output and interconnector import, to reduce the SO's outlay in the BM. Figure 4-11 details the form of the piecewise linear cost function $f(p)$ (as defined in section 4.7.3. for the assessment of outage cost) applied to each generating unit and interconnector, where $OP_g$ is the offer price for generator unit (or interconnector) $g$ in the BM. For plant types which do not have an

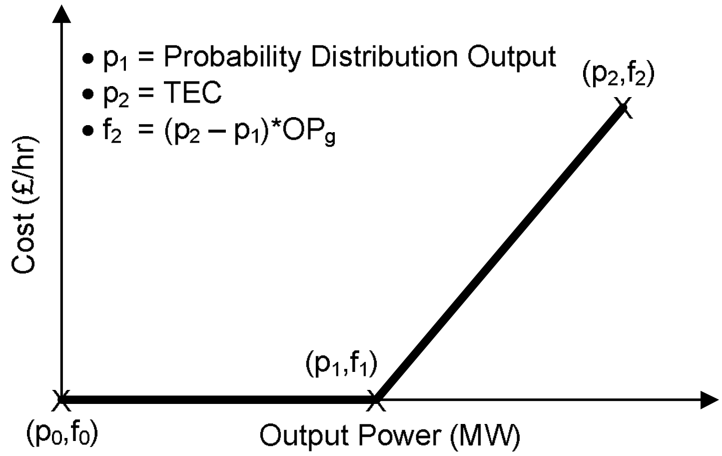


**Figure 4-11 Piecewise linear cost function used to estimate constraint cost**

allocated offer price in the input data (as detailed in Table 4-4), the TEC of each associated generating unit is reduced in the framework to the size of the output assumed from the probability distribution. For the case studies in this thesis, this applies to nuclear, wind, wave, tidal and biomass generation, as well as CHP schemes. Thus, the piecewise linear cost function of these units is formed by the first two points only. Figure 4-12 details the method used to calculate the constraint cost of a network for the winter, summer or summer outage season.

The assessment of annual constraint cost saving, as a result of a reinforcement plan, can be expressed as follows:

$$CC_{SAV} = CC_{ORIG} - CC_{NEW} \tag{4-11a}$$

where

$$CC_{NEW} | CC_{ORIG} = CC_W + CC_S + CC_{SO} \tag{4-11b}$$

$$CC_{W|S|SO} = \sum_{i=1}^{lim} \sum_{g=1}^{G} \{[(COn_g \times OP_g) - (COf_g \times BP_g)] \times S_{DUR}\} \tag{4-11c}$$

and $CC_{SAV}$ is the annual network constraint cost saving as a result of the TRP; $CC_{ORIG}$ and $CC_{NEW}$ is the annual constraint cost of the original base case network and new network (including the TRP) respectively; $CC_W$, $CC_S$ and $CC_{SO}$ is the network constraint cost for the winter, summer and summer outage seasons respectively; $COn_g$ and $COf_g$ is the constrained on and constrained off MW variation in output for generator unit *g*; *G* is the total number of contributory units for the simulation; $OP_g$ and $BP_g$ is the offer price and bid price for generator

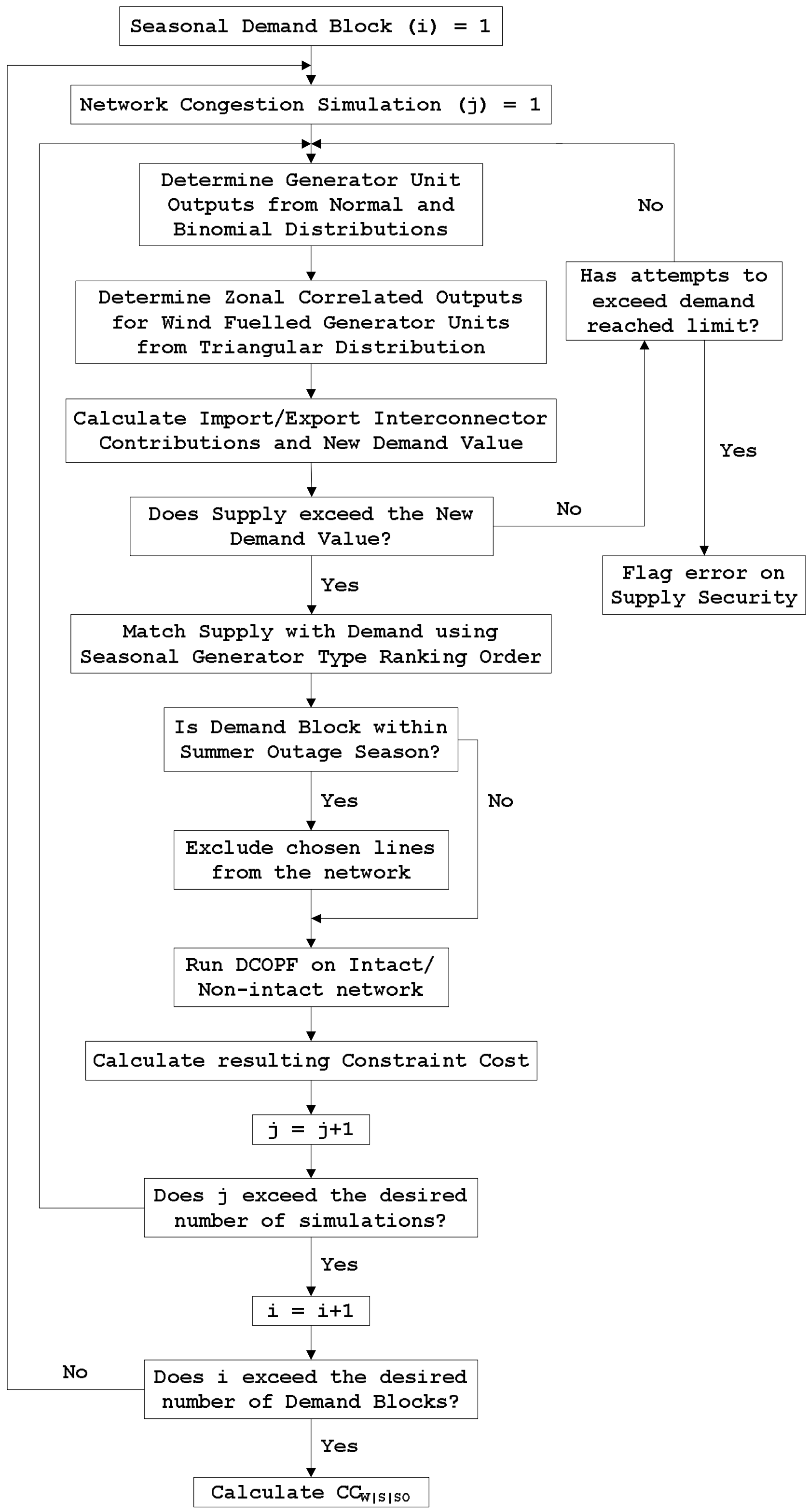


**Figure 4-12 Flowchart of the method used for determining the network constraint**

unit $g$ in the BM, $S_{DUR}$ is the duration (in hours) that the simulation represents, and $lim$ is the limit of DCOPF simulations set for calculating network congestion in the season.

Due to the computational simplifications made in assessing the outage cost resulting from a reinforcement plan (see section 4.7.3.), 100 DCOPF simulations could be carried out for the case studies in this thesis, in the assessment of annual network constraint cost saving across the year. This resulted in a reasonable simulation time for the MOTREP framework to carry out scenario analysis given the iterative nature of the SPEA2. When considering the duration of the three seasons (for the case studies the summer outage season is defined as 8 weeks long, resulting in 23 weeks for the summer season and 21 weeks for the winter season), this results in $lim$ being defined as 40, 44 and 16 within the framework for the winter, summer and summer outage seasons respectively.

The number of DCOPF simulations allocated to each demand level within the season of simulation is dependent upon the duration of the demand block. For example, if a demand block for the estimation of the summer season LDC is 2 weeks in duration, then the number of simulations allocated to that demand level would be 4 (2 weeks is 8.70% of the summer season duration). Further, to calculate $S_{DUR}$ the duration of the demand block is divided by the number of simulations allocated to the demand level. Hence in this example each simulation would represent a duration of 84 hours. Appendix A.3. details the effect of altering the number of simulations on the evaluation time and result of a TRP's outcome on annual network congestion.

A key aspect in employing an MOEA for the optimisation stage is that the objective evaluations in every generation of evolution for all solutions must be evaluated using the same procedure, as the contrary could result in erroneous dominance comparisons and the wrong solutions in the nondominated Pareto set. Hence, for any incidences of random sampling used in the constraint cost saving evaluation (namely in determining generator unit outputs from the probability distributions), the same sequence of random numbers is used to evaluate all TRP solutions. This technique is known as "correlated sampling" and it helps to reduce the variance introduced by random sampling [4.45]. Further, as the computational effort in generating correlated outputs (via batches) for wind generation is too significant for repetition, the correlated values for each wind farm and for each simulation of network congestion, and associated demand block level, are determined prior to the creation of the initial population and are used for all evaluations of annual constraint cost saving within the framework.

It should be noted that winter thermal line ratings are utilised throughout the calculation of $CC_W$, and summer line ratings are utilised in the calculation of $CC_S$ and $CC_{SO}$. This is to consider the reduced thermal line ratings of line conductors in hotter temperatures. As is also the case in assessing outage cost, summer line ratings are therefore needed to be allocated to the reinforcements made by the plan. To do this a suitable summer line rating, from a line in the base case network of identical capacity to the reinforcement, is selected by the framework. If a suitable summer rating cannot be located then a line rating equivalent to the ratio of winter to summer line ratings in the base case network of the reinforcement winter season rating, is used in the framework (for the 2014/15 base case network, an 84% ratio is apparent).

## 4.8. *The Strength Pareto Evolutionary Algorithm 2 (SPEA2)*

The MOTREP framework utilises an elitist MOEA known as the SPEA2 to explore the search space of reinforcement solutions and improve the objective evaluations of the initial population, through an iterative process of population evolution, until a final set of Pareto optimal TRP solutions is obtained. The SPEA2, as with all MOEAs, is based on the original structure of a GA. Following the creation of the initial population (**P**) of TRPs, the SPEA2 procedure with archive size ***N***, and maximum generation limit ***T*** is carried out within the framework as follows:

Step 1: **Initialisation**: Create empty external archive $\mathbf{A_t}$. Set generation count ***t*** to zero.

Step 2: **Fitness assignment:** Calculate the fitness of each TRP in $\mathbf{P_t}$ and $\mathbf{A_t}$ on the requirement of maximising $LL_{SAV}^{YEAR}$ and $CC_{SAV}$ and minimising $IC_{TEP}$, $OC_{TEP}$ and $OM_{TEP}$.

Step 3: **Environmental selection**: Copy non-dominated TRPs of $\mathbf{P_t}$ and $\mathbf{A_t}$ to $\mathbf{A_{t+1}}$. If the size of $\mathbf{A_{t+1}}$ exceeds ***N*** then reduce $\mathbf{A_{t+1}}$ using the truncation operator. If the size of $\mathbf{A_{t+1}}$ is less than ***N*** then fill $\mathbf{A_{t+1}}$ with the fittest dominated TRPs in $\mathbf{P_t}$ and $\mathbf{A_t}$.

Step 4: **Termination:** If $\boldsymbol{t} \geq \boldsymbol{T}$ then the final solution is the non-dominated Pareto set $\mathbf{A_f} = \mathbf{A_{t+1}}$. Stop SPEA2 process.

Step 5: **Mating Selection:** Fill mating pool through performing binary tournament selection on $\mathbf{A_{t+1}}$.

Step 6: **Variation:** Create the new population $\mathbf{P_{t+1}}$ by applying crossover and mutation operators to the mating pool.

Step 7: **Objective Evaluation**: Evaluate $LL_{SAV}^{YEAR}$, $IC_{TEP}$, $OC_{TEP}$, $OM_{TEP}$ and $CC_{SAV}$ (if not previously evaluated in the mutation operator – see section 4.8.6.) of each TRP in $\mathbf{P}_{t+1}$. Increment generation counter ($\boldsymbol{t} = \boldsymbol{t} + 1$) and go to Step 2.

The SPEA2 procedure is an improvement from the original SPEA due to the use of an enhanced fitness assignment procedure in Step 2, the use of a truncation operator in Step 3, and the use of only elite solutions in the external archive for mating selection and population variation [4.29]. As a result, Zitzler *et al.* [4.29] found that the SPEA2 outperformed the original SPEA for both solution convergence and diversity. As detailed in Chapter 2, a multi-objective algorithm needs to satisfy three areas in locating the Pareto set: accuracy, diversity and spread. Steps 2 and 3 are exclusive to the SPEA2 in comparison to other GAs and improve the algorithms performance in all three areas. The enhanced fitness assignment in Step 2 increases selective pressure and, through the use of density information, encourages exploration of less dense regions of the objective space. The truncation operator in Step 3 ensures that a diverse and well-spread set of non-dominated solutions are kept. Steps 2 and 3 of the SPEA2 process are explained next.

## 4.8.1. SPEA2 Fitness Assignment

Deb [4.46] criticised the procedure of assigning fitness values in the original SPEA. Solutions dominated by the same individuals in the Pareto set received the same level of fitness and Pareto set solutions which dominated more solutions were assigned a worse fitness value. Hence in response to these criticisms, Zitzler *et al.* [4.29] proposed a new improved fitness assignment procedure for the SPEA2 which considers for each solution, the number of solutions it dominates and the number of solutions it is dominated by. Firstly, a strength value is assigned to each solution in the combined set **P** and **A**, which corresponds to the number of solutions it dominates. Then a raw fitness value ($R$) is assigned to each solution, which equates to the sum of the strengths of the solutions by which it is dominated by. Figure 4-13 illustrates this process.

The fitness assignment procedure of the SPEA2 ensures that solutions dominated by many individuals are assigned the worse fitness. In response to the criticisms of the SPEA fitness assignment procedure, Pareto optimal solutions are now assigned a similar raw fitness value and solutions dominated by the same individual (particularly in clusters) are assigned different fitness levels according to a more local dominance relationship (i.e. within a cluster). Hence

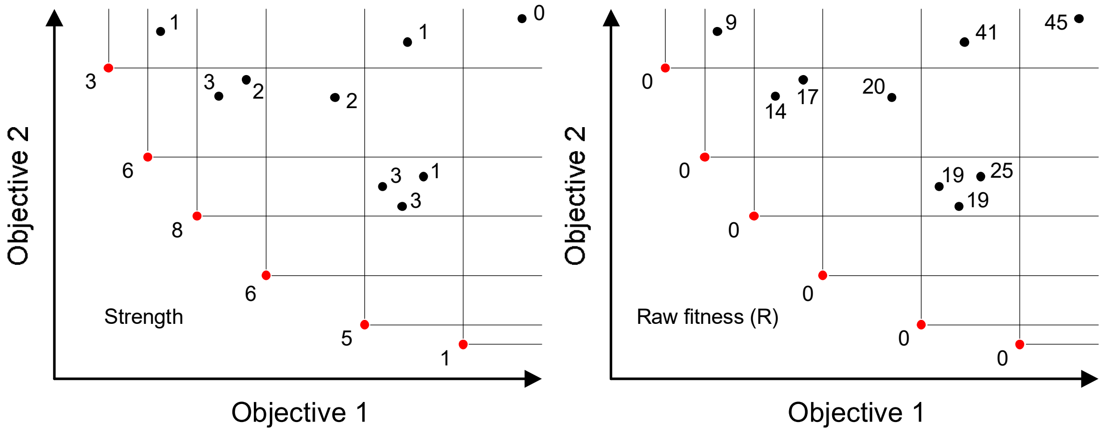


**Figure 4-13 SPEA2 fitness assignment**

as solutions closer to the Pareto front, in less crowded regions, are assigned a better more representative fitness value, the search is pushed towards the Pareto front and towards less crowded regions of the search space.

It is still a possibility that solutions within the search space, particularly for larger population sizes, will be allocated an identical raw fitness value. To discriminate between these individuals, $R$ is corrected using an estimation of local density ($D$), which is evaluated using the inverse of the distance to the $k^{\text{th}}$ nearest neighbour:

$$D(i) = \frac{1}{\sigma_i^k + 2} \tag{4-12}$$

where $\sigma_i^k$ is the distance to the $k^{\text{th}}$ nearest neighbour for individual $i$. This technique is an adaptation of the original $k^{\text{th}}$ nearest neighbour method proposed by Silverman [4.47]. A common setting in the SPEA2 is to use a value of $k$ equal to the square root of the size of the combined set **P** and **A**. A two is added to the denominator to ensure that $0 < D(i) < 1$ and the domination count of $R$ is not affected. The resulting fitness $F$ of each individual is the sum of the raw fitness $R$ and density estimation $D$:

$$F(i) = R(i) + D(i) \tag{4-13}$$

These values of solution fitness are used to choose through environmental selection, individuals from the combined set that will be placed in the external archive for the next generation. Only the fittest solutions survive to be selected for mating and are subsequently varied through the crossover and mutation operator.

### 4.8.2. SPEA2 Environmental Selection

When updating the external archive the method employed by the SPEA2 differs from the SPEA by; a) keeping the size of the archive constant, and b) using a truncation operator to ensure individuals are well spread and boundary solutions are not removed. When the non-dominated solutions in the sets $\mathbf{P_t}$ and $\mathbf{A_t}$ are copied to the archive ($\mathbf{A_{t+1}}$), three options exist:

- The set of non-dominated solutions is exactly the same size as $\mathbf{A_{t+1}}$. In this case the environmental selection step finishes.
- The set of non-dominated solutions is smaller than $\mathbf{A_{t+1}}$. In this case $\mathbf{A_{t+1}}$ is filled with the best dominated solutions in the previous archive and population sets (implemented by sorting the previous dominated solutions according to assigned fitness values and copying the required number of solutions from the top of the resulting ordered list).
- The set of non-dominated solutions is larger than $\mathbf{A_{t+1}}$. In this case a truncation operator is invoked to iteratively remove solutions from the set until its size matches the size of $\mathbf{A_{t+1}}$.

At each iteration of the truncation operator, the solution in $\mathbf{A_{t+1}}$ with the closest distance to another solution is chosen. If there are several individuals with minimum distance, the solution is removed from $\mathbf{A_{t+1}}$ by considering the second closest distances and so forth. Figure 4-14

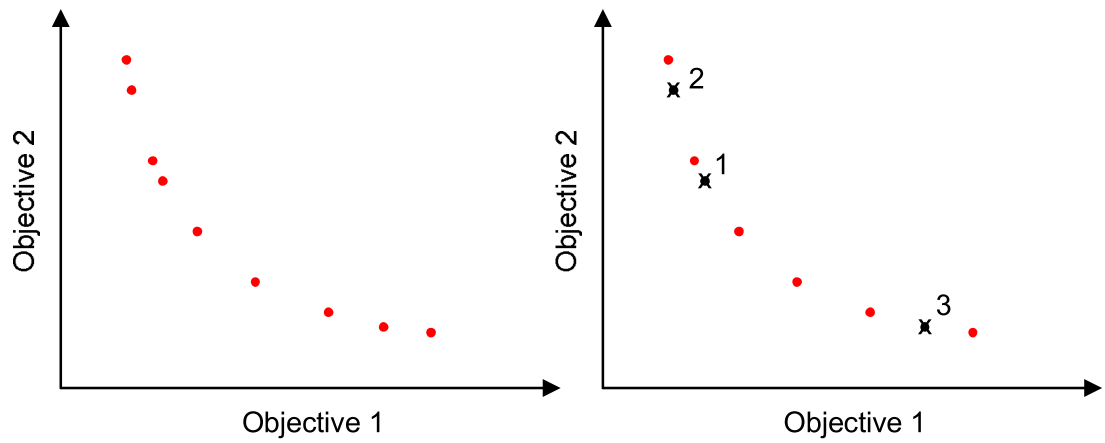


**Figure 4-14 SPEA2 archive truncation method**

illustrates how the truncation operator functions. The graph on the left shows the original non-dominated set. The graph on the right depicts which solutions the truncation operator will remove in which order, assuming that the size of the archive is 6.

### 4.8.3. SPEA2 Parameters

The SPEA2 adapted for the MOTREP framework requires 8 parameters. These are the population size, the archive size, the number of generations, the crossover type, the probability of crossover, the mutation route, the mutation probability type and probability of mutation. The parameters required in the crossover and mutation operators are explained and discussed in sections 4.8.5. and 4.8.6. respectively. Here, the remaining SPEA2 parameters are discussed.

The size of the population is a key input for achieving an efficient GA. Some authors recommend a population size of less than 100 individuals [4.48]. Deb [4.46] demonstrated that the optimal population size depends on the difficulty of the problem (i.e. the size of the search space and the number of variables). The greater the difficulty of the problem, the larger the population should be. Alarcón-Rodríguez [4.49] used a population size of up to 400 individuals for the application of distributed energy resource planning. Goldberg [4.50] states that although a small population causes the GA to converge more quickly, a population too small will lack solution diversity and cause the algorithm to converge to local optima. Hence to force the GA to converge to the global optima, the population size must be large enough for the complexity of the problem to provide the GA with a good number of diverse solutions from the pre-defined search space. However, if the population is too large, evolution towards Pareto optimality will require a longer computation time, reducing the efficiency of the GA.

The archive size is also a key parameter for the SPEA2. Only solutions from the archive can be selected and evolved through crossover and mutation. A large archive with too many non-dominated solutions could consist of many solutions with similar fitness, decreasing selection pressure [4.51]. For case studies in his doctoral thesis that used the SPEA2 algorithm, Ziztler [4.52] used archive sizes between 25% and 80% of the population size. Alarcón-Rodríguez [4.49] used similar archive sizes of between 25% and 75%. Further, Rivas-Davalos *et al.* [4.53] used an archive size that was 25% of the population size for the application of distribution network planning. On the other hand the SPEA2, on its original conception [4.29], and in the comparison study (with the NSGA-II) by Mori *et al.* [4.54], was used with an archive size set equal to the population size (a size between 250 and 400 [4.29] and a size of 100 and 200 [4.54]). For the case studies conducted in this thesis, population sizes between 120 and 200 members were used and archive sizes were set equal to between 60% and 67% of these population sizes.

The termination of the SPEA2 algorithm (Step 4) is defined by the number of generations. Care must be taken to ensure that the generation limit is not set too low and that the SPEA2 is not halted prematurely in its pursuit of the Pareto front. When carrying out the analysis for the case studies of this thesis, the output of the SPEA2 was analysed after 200 generations before then continuing from the termination point of the last generation (i.e. Step 4) for another 100 generations. If the output of the SPEA2 closer represented the shape of the expected Pareto front after an extra 100 generations then the process was continued until there was no significant visible change in the plotted outputs. For the case studies conducted in this thesis, an overall generation limit between 200 and 400 was required.

The implementation of the SPEA2 in Matlab was validated using test functions prescribed by Zitzler *et al*. [4.29] for which the Pareto front is known.

### 4.8.4. TRP Encoding

To implement the SPEA2 a consistent structure needs to be used to represent a TRP for the creation of new plans during population variation. As described in section 4.6., to create a TRP three reinforcement options are firstly generated to alleviate each thermal limit violation located under a selected maximum power flow condition, $PFC_{MAX}$; an option for line reconductoring, single-circuit line addition and double-circuit line addition. The reinforcement plan is then created by selecting a combination of these three options whilst ensuring that the right-of-way limit is adhered to.

The MOTREP framework uses a matrix to represent a TRP whereby each row represents a reinforcement option and each column represents a required characteristic of the reinforcement. Integer encoding is used as opposed to binary encoding. The first five columns detail the required data for the reinforcement option to be included directly in the branch data input matrix for the implementation of a DCPF/DCOPF on the combined network (i.e. base case network including the TRP). These inputs are the bus number (i.e. network node) at the “from” end (fbus) and “to” end (tbus), reactance (in per unit), seasonal thermal line rating

(MVA) and status (1 = in-service, 0 = out-of-service) of the reinforcement option. The status of all the reinforcement options within the TRP matrix is always defined as in-service.

The next three columns detail the resistance (in per unit), the length of OHL section (in km) and the length of UGC section (in km) for each reinforcement option. These are inputs required in the calculation of annual line loss saving, capital investment cost, incremental O&M cost and outage cost (through assessing the outage duration) of a reinforcement plan. The initial information for these columns is obtained directly from the base case network data at the location of the thermal limit violation for the reinforcement option. When altering the capacity of a reinforcement option in (4-4), the data on the resistance, reactance and thermal line rating of the option within the TRP matrix is altered accordingly.

The last three columns in the TRP matrix detail the type of reinforcement option (using a key that denotes a double-circuit as 2, a single-circuit as 1 and a line upgrade as 0), the existing number of circuits connected across the route (from bus $i$ to $j$) in the base case network, and the selection made using binary notation (1 = selected, 0 = de-selected). The ROW constraint is applied to the TRP matrix by ensuring that the sum of the selected reinforcements (binary notation × reinforcement key) across the line route, added to the number of existing circuits, does not exceed the selected ROW constraint. Only reinforcement options which have been selected in the TRP matrix are included in the combined network for testing and assessment. Figure 4-15 details the final structure of the TRP matrix used to encode the plan. For the purpose of population variation through applying crossover and mutation operators, each

TRP Matrix

| | branch parameters | | | | | objective parameters | | | selection parameters | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | fbus | tbus | reactance(pu) | rating(MVA) | status | resistance(pu) | OHL(km) | UGC(km) | type | circuits | selection |
| violation 1 | 1 | 297 | 0.009825 | 1390 | 1 | 0.001046 | 48.88 | 0 | 2 | 1 | 1 |
| | 1 | 297 | 0.009898 | 2400 | 1 | 0.000915 | 48.88 | 0 | 1 | 1 | 1 |
| | 1 | 297 | 0.009164 | 2010 | 1 | 0.000830 | 48.88 | 0 | 0 | 1 | 1 |
| violation 2 | 37 | 699 | 0.004358 | 1260 | 1 | 0.000410 | 11.089 | 0 | 2 | 2 | 1 |
| | 37 | 699 | 0.002129 | 1710 | 1 | 0.000233 | 11.089 | 0 | 1 | 2 | 0 |
| | 37 | 699 | 0.001677 | 2130 | 1 | 0.000193 | 11.089 | 0 | 0 | 2 | 1 |

**Figure 4-15 Matrix structure used to encode a reinforcement plan**

reinforcement proposal for each discovered thermal limit violation is a gene within the chromosome that is the overall reinforcement plan. Hence each gene consists of a line upgrade option, an option for single-circuit addition and an option for double-circuit addition, as well as the selections made to adhere to the ROW limit.

## 4.8.5. Binary Tournament Selection

Mating selection for reproduction occurs after fitness assignment and environmental selection in the SPEA2 process. In comparison to other reproduction operators, binary tournament has an improved or equivalent convergence and computational efficiency [4.46]. For mating selection, the binary tournament operator has been utilised and is implemented using the procedure detailed in Figure 4-16. Binary tournament selection is performed on the external

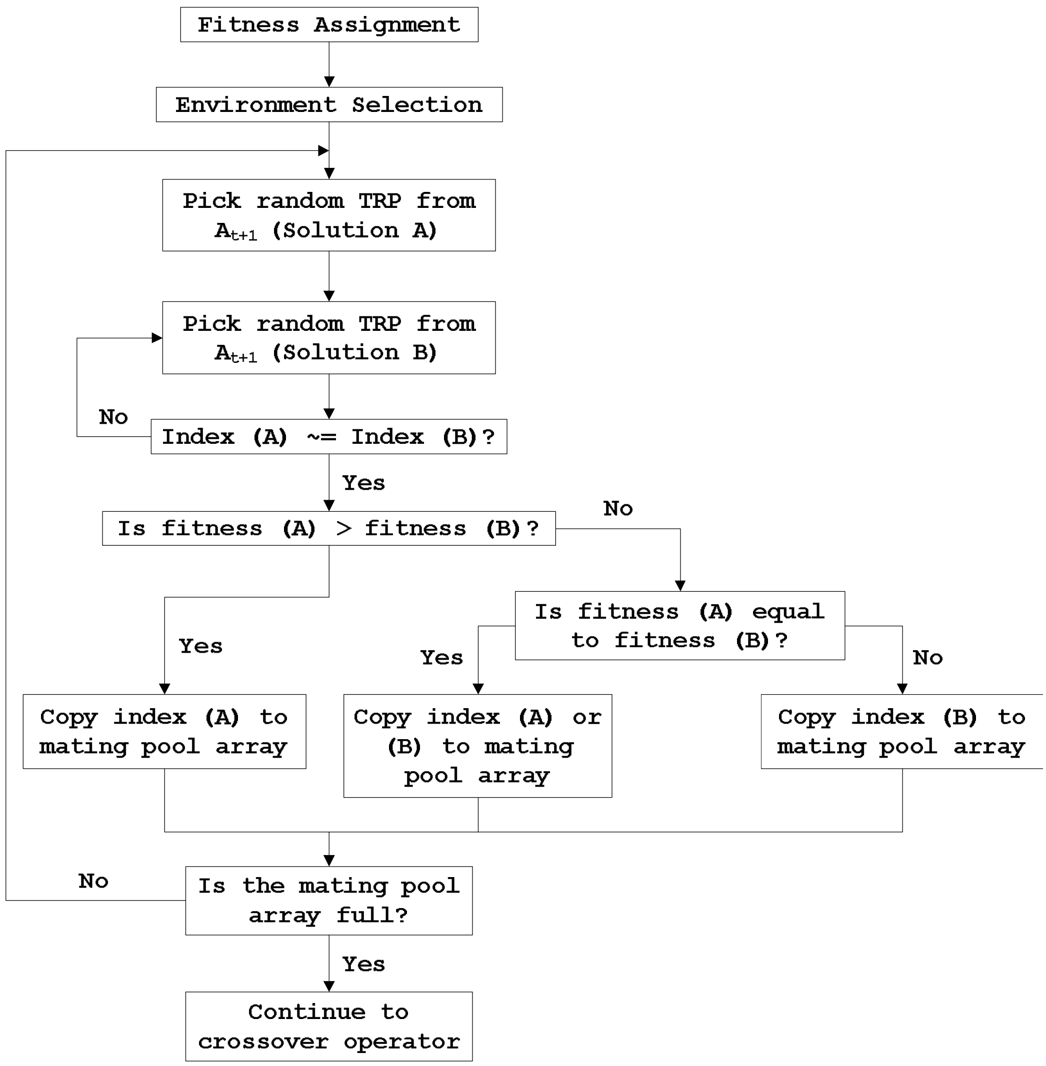


**Figure 4-16 Binary tournament procedure**

archive ($A$) of the generation ($T$) in the SPEA2 process. Pairs of TRPs are chosen at random and their fitness is compared. The index of the fittest TRP is stored in a mating pool array. If two reinforcement plans have the same fitness value (an unlikely event) then one of them is chosen randomly and the respective index is copied to the mating pool array. The process for binary tournament selection is repeated until the mating pool array is filled and enough TRP solutions have been chosen to create a completely new population. Since each chromosome or "parent" (i.e. TRP) creates a new reinforcement plan, via the crossover and mutation operators, the size of the mating pool array is defined as being equal to the size of the population.

### 4.8.6. Crossover Operator Implementation

As reinforcement plans are generated for varying conditions of maximum power flow ($PFC_{MAX}$) – to enable the SPEA2 to explore reinforcement solutions in different areas of the network – each encoded TRP consists of a matrix containing a different number of rows. The crossover operator is used in a GA to combine pairs of chromosomes from the mating pool (called "parents") by exchanging their genes to produce a new pair of chromosomes (called "offspring"). To carry out crossover for this application a gene consisting of a reinforcement solution along a network route is swapped with a gene consisting of a different reinforcement solution along the same network route.

To swap genes between paired solutions a matrix is first generated for each "parent" which details the reinforcement solutions of the plan along network routes that are related to the other solution. The reinforcement solutions in this matrix are excluded from the parent solutions, before being combined through crossover. The resulting altered reinforcement solutions are then inserted back into the parent TRP matrices, creating the new parent solutions for the next population. Figure 4-17 illustrates this process. Three methods for crossover have been included for use in the framework; single-point, double-point and uniform crossover. Single-point crossover refers to splitting the two parent chromosomes at a single random point and swapping over the genes. The offspring therefore inherits one sequence of genes from each parent. Double-point crossover refers to splitting the parent chromosomes at two random points and swapping over the genes between the two cutting points. Uniform crossover refers to splitting the parent chromosomes at multiple points using a 'crossover mask', based on a uniform probability distribution, and exchanging the corresponding segments between parents.

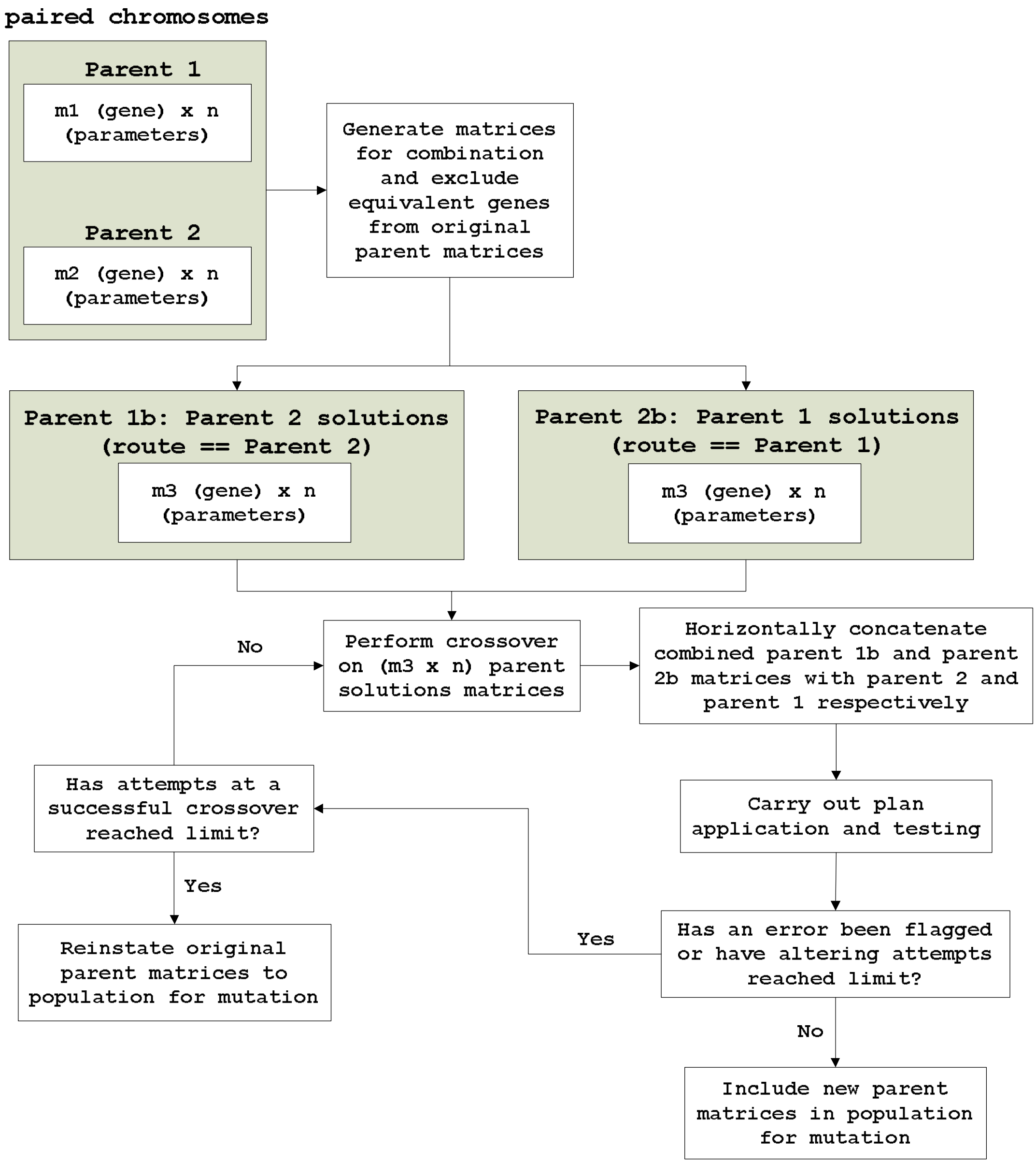


**Figure 4-17 Method used to perform crossover on paired parent solutions**

When carrying out single-point or double-point crossover, large groups of adjacent genes are swapped at once. This means that groups of genes from the initial population of reinforcement solutions are likely to remain together for several evolutionary generations. These operators therefore disrupt the population of solutions to a lesser extent, relying more heavily on the use of the mutation operator for evolution of the population. Uniform crossover on the other hand swaps each gene individually (as opposed to in groups), according to the 'crossover mask' (an array of 1's and 0's) equal in size to the number of genes able to be swapped. This crossover method is more disruptive and explores a wider range of the created search space. Hence new mixes of reinforcement solutions in a plan are created at each evolutionary generation, increasing the likelihood that an optimal solution for the pre-defined search space will be located. Haupt *et al*. [4.55] found that uniform crossover performed better than single or double-point crossover for this reason. Hence, for the case studies analysed in this thesis, uniform crossover is selected.

After crossover has been performed on the parent solution matrices and new reinforcement plans are generated (see Figure 4-17), the method detailed in Figure 4-3 for plan application and testing is carried out on each TRP (contributory generating units are identified at ACS peak demand for the scenario and generating unit outputs are set using the EPTC method). As most genes, particularly through uniform crossover, have been swapped it is possible that the new combination of reinforcements within each TRP can exacerbate thermal related network issues in other areas of the network. Hence this process is carried out – as is the case in generating initial population solutions – to make minimum necessary adjustments to the plan (thereby maintaining the characteristics of the TRP) in the elimination of thermal limit violations that exist on the combined network, in excess of the most onerous power flow condition (84% in this case). An iterative process is performed to alter a plan and avoid an error being flagged up in the testing process. If multiple attempts have been made for a successful crossover and one or both combined TRPs still result in an error being flagged, then the original solutions are reinstated into the new population. However, in practice this rarely occurs and new successful plans are often generated and included in the new population for mutation (if selected).

An input denoting the probability of crossover is used to define the frequency at which the overall process is performed. When moving through paired TRPs in the mating pool, the process outlined in Figure 4-17 is carried out if a random number drawn from a uniform distribution in the interval (0,1) is less than the defined probability for crossover. The SPEA2 is an elitist algorithm which uses an external archive to preserve non-dominated, optimal solutions for the next generation. A high crossover rate (from 0.8 – 1.0) is commonly used in elitist MOEA [4.46],[4.51]. For the case studies analysed in this thesis, a crossover rate of 0.9 is applied. Hence only 10% of the paired parent solutions in the mating pool are not combined. This was found to generate satisfactory outputs for the multi-objective problem.

## 4.8.7. Mutation Operator Implementation

The mutation operator alters genes within the offspring chromosome after crossover; maintaining population diversity through the exploration of the decision space. For this application, mutation of a gene involves altering the selection of reinforcement options (line upgrading, single-circuit and double-circuit addition) and varying the thermal line rating of each option. The new selection is made whilst ensuring that the ROW limit is adhered to. To alter the thermal line rating of each reinforcement option, the overall plan (following the alteration of a single genes selection) is firstly applied to the base case network of the case study and a DCPF is carried out (contributory generating units are identified at ACS peak demand for the scenario, and generating unit outputs are set using the EPTC method). The new line capacities of each reinforcement option for the chosen gene to be mutated are then obtained using the procedure in (4-4); allowing for a pre-defined number of attempts at locating a satisfactory line rating.

When moving through the genes within each TRP, a gene mutation is performed if a random number drawn from a uniform distribution in the interval (0,1) is less than the defined probability for mutation. Once the process is completed and the percentage of genes within the plan is mutated at a rate that reflects the required probability, the method detailed in Figure 4-3 for plan application and testing is carried out. If an error is flagged up from the process or altering attempts have reached a limit then the reinforcement plan is reset back to its original form, before mutation. The process of gene mutation is repeated until a successful mutated TRP is found. Two possible routes exist in the overall procedure of this operator.

- Route 1: The annual constraint cost saving of the TRP is assessed and only mutated reinforcement plans that achieve a $CC_{SAV} \geq 0$ are included in the evolved population. This is to match the criteria of plans created for the initial population.
- Route 2: The successfully mutated TRP (after plan application and testing) is included directly into the evolved population. This route relies more on the quality of the initial population solutions. It is likely for this route that the SPEA2 will require more generations and a larger population size and archive size to locate optimal solutions that lie on the Pareto front for the multi-objective problem.

To carry out Route 1, if a successfully mutated TRP (after plan application and testing) causes an increase in network congestion (over the unexpanded base case network) then several attempts are made at repeating the mutation process. If after a pre-defined number of attempts, a successfully mutated TRP still exacerbates network congestion then the probability of mutation is increased – using the formula: $probability = probability + (probability \times 0.25)$ – and the overall process is repeated until a successfully mutated reinforcement plan results in a $CC_{SAV} \geq 0$.

As mutation is a disruptive operator, a low probability of occurrence is advised. Man *et al.* [4.56] suggests using a mutation rate of only 0.001 for large populations (100) and a mutation rate of 0.01 for small populations (30). Route 2 is likely to require a larger population size than Route 1; hence for Route 2 a low mutation probability is advised. Deb *et al.* [4.57] employed a probability equal to *1/n* where *n* is the number of genes when using the NSGA-II. Alarcón-Rodríguez [4.49] also used this mutation rate for the SPEA2 in the application of distributed energy resource planning. Hence, on average one gene of each chromosome is mutated in each generation. The solutions generated from the MOTREP framework can consist of a different number of genes (according to Figure 4-4, around 50 genes at 84% $PFC_{MAX}$ and over 200 genes at 42% $PFC_{MAX}$), hence if a probability of *1/n* is employed then a different mutation rate would be applied to each plan. To maintain consistency across the population, a flat mutation rate of 0.001 is used for case studies involving the Route 2 option.

For Route 1 a smaller population size is likely to be required. The mutation operator is vital for maintaining population diversity and allows exploration of regions of the decision space not previously explored [4.46]. According to Beasley *et al.* [4.58], the optimal mutation rate is more important than an optimal crossover rate. Haupt *et al.* [4.55] proved that a diverse set of solutions could be maintained by increasing the mutation rate when the population size is decreased. However too high a mutation rate (>0.5) as demonstrated by Goldberg [4.50], converts the search into a random search. Hence to ensure adequate population diversity for Route 1, a flat mutation rate of 0.4 is used in the case studies.

The mutation rates employed are static, however the option to use a dynamic mutation rate as suggested by Beasley *et al*. [4.58] – where the rate is adapted from high (exploratory) to low (fine-tuning) as the SPEA2 moves from generation to generation – is included in the framework. For the case studies analysed in this thesis, the use of a dynamic mutation rate in comparison to a flat rate caused the SPEA2 to produce (for the same number of generations) more solutions that did not lie on the Pareto front. Hence a dynamic mutation rate was not used to generate the case study results in Chapter 5.

### 4.8.8. SPEA2 in Power Systems

MOEA's have only recently gained attention in the power systems community, however in the past few years MOEA's have been applied to a wide range of power system problems. Originally (within the power system community) the SPEA2 was applied to the distribution system expansion planning problem. Rivas-Davalos *et al*. [4.53] proposed the use of the SPEA2 to select the number, site and size of substations and network lines such that the investment cost, the cost of energy losses and the energy not-supplied (a reliability index based on assumed failure rates and failure durations of each line in the system) were at a minimum. For the case study proposed, two sizes of substation and conductor were considered as the candidates for the problem and these magnitudes remained constant throughout the optimisation process. Further, a chromosome consisted of an integer number representation of the number of pre-defined lines used in each solution. It was concluded that the SPEA2 was a success at locating Pareto-optimal solutions for the complexity of the problem, which included constraints on line capacity (i.e. thermal line rating) and nodal voltage.

Ganguly *et al.* [4.59] also utilised the SPEA2 for the same problem and for the same objectives as Rivas-Davalos *et al*. [4.53]. Here a heuristic-based conductor size selection algorithm is used to include further variation (in comparison Rivas-Davalos *et al.* [4.53]) in thermal line ratings in the optimisation. However, the conductor size selection algorithm is only used as a support subroutine to the main algorithm and therefore is not included in the encoding of the solution. Therefore regarding conductors, unlike the algorithms application here, the SPEA2 is not used to locate Pareto-optimal expansion solutions for size, but only Pareto-optimal solutions for the number and location of the conductors.

Mori *et al*. [4.54] proposed the use of the SPEA2 for a similar problem as Rivas-Davalos *et al.* [4.53], only in this case the objective to minimise energy not-supplied was excluded and an objective to minimise voltage deviation was included. Binary encoding was used here to represent the substation and network line investment decisions. As detailed in Chapter 2, this paper compares the SPEA2 with the NSGA-II and concludes that the SPEA2 outperformed the NSGA-II method for both solution quality (accuracy and spread) and computational efficiency.

Following the studies by Mori *et al*. [4.54] and Rivas-Davalos *et al*. [4.53] the SPEA2 has since been applied successfully to a wide range of power system problems; from distribution network reconfiguration problems [4.60]-[4.61], namely the operation, location and number of sectionalizing switches and tie lines within the network, to distribution energy resource planning [4.49] and in low voltage smart grids for performing a probabilistic reliability assessment [4.62] or for developing a multi-objective dispatch optimisation strategy [4.63]. Further, the algorithm has also been successfully applied to solve the multi-objective problem of economic environmental dispatch (to minimise fuel cost and emissions) [4.64] and reactive dispatch (to minimise active losses, voltage deviations and cost of compensation devices) in a transmission system [4.65]. Additional applications of the SPEA2 exist within the power system community. Chapter 2 summarises a recent application of the SPEA2 for transmission expansion planning [4.66], and highlights the simplifications and limitations of the proposed approach. In general, there is a lack of modelling approaches and frameworks which employ the SPEA2 for the transmission planning problem. The SPEA2 has been chosen for use in the MOTREP framework due to the success of the algorithm in the above power system related problems.

## 4.9. *Security Testing of Non-dominated Reinforcement Plans*

The non-dominated Pareto set of reinforcement plans created by the SPEA2 need to satisfy predefined rules for network security and reliability. These are rules by which the performance of the transmission network against component failures and outages (due to maintenance) can be judged acceptable or unacceptable. Deterministic security criteria have traditionally been utilised to test network security and reliability. Under deterministic criteria, an operating condition is identified as secure if the system is stable and no violation of thermal loading and voltage conditions occurs as a result of each contingency in a pre-specified contingency set.

For the case studies in this thesis the framework needs to generate plans that satisfy applicable security criteria outlined in the NETS SQSS [4.17]. As a DC power flow-based model of the GB transmission network is used the TRPs are tested against thermal constraint criteria only. Chapter 2 details the security criteria outlined in the NETS SQSS. The thermal criterion is currently deterministic and requires that at ACS peak demand there shall not be unacceptable thermal overloading[10] of any transmission equipment in the event of the fault outage of a single transmission circuit (an N-1 contingency), a double-circuit OHL (an N-D contingency, excluding double-circuits located only in SPT's transmission system at a voltage level of 132kV) or a single circuit with the prior outage of another circuit (an N'-1, N-1-1 or N-2 contingency), where both circuits are located in NGET's transmission system.

Due to the size of the base case network used in the thesis case studies, the computational effort to carry out a full N-1 contingency security assessment on the combined network (TRP and base case network) is significant. Therefore, as opposed to performing the security test during the process for plan application and testing in the generation of the initial population (see Figure 4-3), and discarding reinforcement plans that fail the security criteria at this stage, the security test is carried out after the SPEA2 optimisation stage on each located non-dominated TRP within the created set ($A_F$).

The background conditions required for testing transmission networks against the deterministic security criteria (according to the NETS SQSS) are that generating unit outputs and power flows are set to those that arise from the EPTC method, and that set power flows are modified by an appropriate application of the boundary allowance (Appendix F in [4.17]) under the fault outage studied. The boundary allowance (in MW) is added to the transfers arising out of the EPTC method to take into some account the year-round variations in levels of generation and demand [4.17]. Application of the boundary allowance involves separating the transmission network into two contiguous parts, irrespective of the size or location of the parts. Generation and demand in both parts is proportionally scaled such that the transfer of power between the two parts increases by the full boundary allowance for single fault outages and half the boundary allowance for an N-D or N-2 outage. More specifically, if area 1 is exporting to area 2 then the total demand of area 1 (and therefore demand at each network node) is proportionally reduced and the total generation output of area 1 (and therefore the output from each generating unit) is proportionally increased, and in area 2 total demand and generation is proportionally increased and decreased respectively. Hence the export of power from area 1 to area 2 is increased ensuring that total demand and generation of the overall network remains the same. Appendix F of the NETS SQSS [4.17] outlines the technique used by the transmission licensees for defining and applying proportionality to the two contiguous parts in the application of the boundary allowance.

[10] Beyond the specified time-related capability [4.17].

The boundary allowance can be applied to each wider system boundary in the GB transmission network. Chapter 2 outlines the boundary methodology employed by the GB TNOs and SO for transmission planning, and the current wider system boundaries proposed for the GB network. For the case studies in this thesis, the MOTREP framework tests the security capability of the TRPs by applying the boundary allowance to key transmission circuits on boundary 6, which cross the border between Scotland and England. To split the network into two contiguous parts, an integer input is used by the framework to denote the generation zone at which to divide the network. The zones allocated a number less than or equal to the selected generation zone are included in area 1; the zones allocated a number above are included in area 2. The generation zone chosen for the case studies analysed in this thesis is zone 8, which results in area 1 representing Scotland and area 2 representing England and Wales (see the zonal diagram of the GB transmission network in Figure 4-1 for reference).

Each non-dominated TRP is tested against every N-1 outage (under the full boundary allowance condition), every applicable N-D outage and then every critical and applicable N-2 outage combination defined by a contingency set (both N-D and N-2 contingencies are tested under the half boundary allowance condition). A full N-2 contingency security assessment, where both circuits are in NGET's transmission system, is not recommended for the size of the GB base case network due to the computational effort required. The critical outages for N-2 contingency analysis are the circuits that cross wider system boundaries defined for NGET's transmission system [4.67]. These are boundaries 7, 7a, 8, 9, 13, 13e and 14 (see Figure 2-1 in Chapter 2). Boundary 13e runs parallel with boundary 13 but encompasses the network nodes at Nursling, Marchwood and Fawley. These boundaries cross critical circuits for the security of the network [4.67]-[4.68]. The following lines are therefore included in the N-2 contingency set for the case studies analysed in this thesis:

- **Across Boundary 7:** Three double-circuit 400kV lines from Harker to Hutton, Norton to Osbaldwick and Lackenby to Thornton.
- **Across Boundary 7a**: Two single-circuit 400kV lines from Penwortham to Padiham and Kearsley, and two single-circuit 275kV lines from Penwortham to Washway Farm.
- **Across Boundary 8**: Two double-circuit 400kV lines from Keadby to Cottam and West Burton. Three single-circuit 400kV lines from Macclesfield to Cellarhead and

Legacy to Ironbridge and Shrewsbury. A double-circuit 275kV line from Chesterfield to High Marnham and a single-circuit 275kV line from Thurcroft to High Marnham.

- **Across Boundary 9**: Three double-circuit 400kV lines from Enderby to Patford Bridge, Spalding North to Walpole and Cottam to Eaton Socon, and four single-circuit 400kV lines from Feckenham to Minety and Walham, and Grendon from West Burton and Staythorpe.
- **Across Boundary 13**: A double-circuit 400kV line from Hinkley Point to Melksham and two single-circuit 400kV lines from Mannington to Nursling and Fawley.
- **Across Boundary 13e**: A double-circuit 400kV line from Nursling to Lovedean and two single-circuit 400kV lines from Fawley to Botley Wood and Lovedean.
- **Across Boundary 14**: Seven double-circuit 400kV lines from East Claydon to Amersham Main, Bramley to West Weybridge, Northfleet East to West Thurrock, Tilbury to West Thurrock, Sundon to Elstree, Pelham to Rye House, and Kemsley to Littlebrook. Also, one double-circuit 275kV line from Elstree to Warley.

Figure 4-18 outlines the method used by the framework to test the thermal security of a non-dominated reinforcement plan against N-1, N-D or N-2 contingencies. The security testing process for each outage involves the implementation of a DCPF (nodal demands are set from the ACS peak demand value for the scenario year and scenario generating unit outputs derived using the methods detailed in sections 4.3.1. and 4.5. respectively) and the location of thermal overloads in the combined network following the application of the appropriate boundary allowance and the alteration of the specified circuit(s) status (in the branch data input matrix) from in-service to out-of-service. If no overloads are located, then the combined network is tested against the next outage. If a thermal overload occurs, then a DCOPF is implemented (a universal cost is applied to each contributory generating unit). If a thermal overload still exists after the DCOPF then the reinforcement plan, deemed to fail the security test, is removed from the non-dominated set. Experience shows that this rarely occurs in practice as each TRP, for the case studies analysed in this thesis, is designed to adhere at a minimum to a maximum power flow condition ($PFC_{MAX}$) of 84%. This is therefore an important consideration when selecting the limits of $PFC_{MAX}$.

Double-circuit lines are defined in the combined network by locating circuits with identical characteristics in the branch data matrix. If for example three or four circuits exist between two network nodes, where each circuit is identical in length and impedance, then each potential

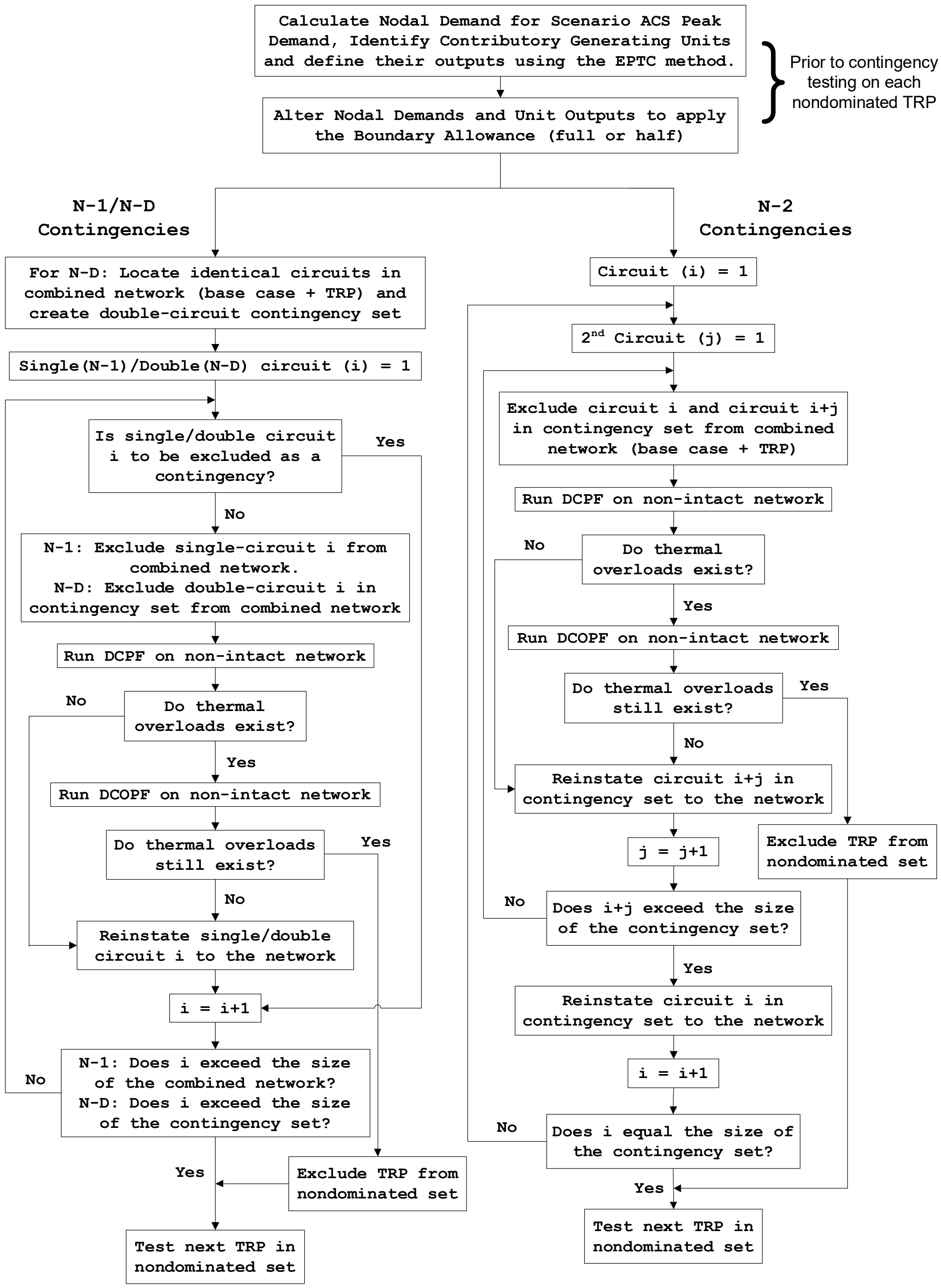


**Figure 4-18 Flowchart of the methods used for testing a non-dominated reinforcement plan against N-1, N-D or N-2 contingencies**

double-circuit combination is tested against. During the contingency analysis, there is the possibility that electrical islanding in the base case network could occur, potentially resulting in an error when implementing the DCPF or DCOPF. To avoid electrical islanding, circuits deemed to cause islanding of the base case network when removed can be excluded from the contingency analysis. These circuits are defined via an input array for N-1 or N-D outage considerations. For N-D outages, the input array also contains circuits to be excluded due to the NETS SQSS criteria; double-circuit lines located in SPT's transmission system at a voltage level of 132kV.

# 4.10. *Summary of Required Framework Inputs*

To carry out the process described in this chapter and enable flexibility in the systematic approach proposed, the MOTREP framework has been designed to use many inputs for scenario analysis. Some of these inputs are in the form of arrays and matrices. Table 4-6 provides an overall summary of the inputs required, detailing their use and whether the inputs have been fixed or varied for the case studies analysed in this thesis. The design of the framework allows for a degree of flexibility in all inputs.

**Table 4-6 Inputs for the MOTREP Framework**

| Input | Function | Fixed/Varied in Case Studies |
|---|---|---|
| **Bus data (for each node of the base case network)** | | |
| Bus number (integer of node) | To carry out DCPF/DCOPF. | Fixed |
| Bus type (1 = no generator connection, 2 = generator connection, 3 = reference bus, 4 = isolated) | To carry out DCPF/DCOPF. | Fixed |
| Power demand at winter peak (MW) | To set nodal demand (for DCPF/DCOPF) of the scenario at ACS winter peak demand or during the winter season (to calculate $CC_{SAV}$). | Fixed |
| Power demand at summer minimum (MW) | To set nodal demand (for DCPF/DCOPF) of the scenario from the median summer minimum demand value of the case study (to calculate $OC_{TRP}$) or during the summer season (to calculate $CC_{SAV}$). | Fixed |
| Voltage magnitude (per unit) | To carry out DCPF/DCOPF. | Fixed |
| Base voltage (kV) | To carry out DCPF/DCOPF. | Fixed |
| Max/min voltage magnitude (per unit) | To carry out DCPF/DCOPF. | Fixed |
| Generation Zone (integer input) | For allocating generating units to a zone based on the connection location. Needed to split the network in the calculation of nodal demand, apply locational TNUoS tariffs in the calculation of $OC_{TRP}$, create correlated availabilities for wind generating units in the assessment of $CC_{SAV}$ and separate the transmission system into two areas for the application of the Boundary Allowance. | Fixed |
| **Branch data (for each line and network component of the base case network)** | | |
| "from"/"to" end bus number (integer of node) | To carry out DCPF/DCOPF. | Fixed |

## Table 4-6 Inputs for the MOTREP Framework

| Input | Function | Fixed/Varied in Case Studies |
|---|---|---|
| Resistance (per unit) | To assess $LL_{SAV}^{YEAR}$. | Fixed |
| Reactance (per unit) | To carry out DCPF/DCOPF. | Fixed |
| Winter line rating (MVA) | To carry out DCPF/DCOPF of the scenario at winter peak demand or during the winter season (to calculate $CC_{SAV}$). | Fixed |
| Summer line rating (MVA) | To carry out DCPF/DCOPF of the scenario for the median summer minimum demand value of the case study (to calculate $OC_{TRP}$) or during the summer season (to calculate $CC_{SAV}$). | Fixed |
| Status (1 = in-service, 0 = out-of-service) | To carry out DCPF/DCOPF. | Fixed |
| Length of OHL/UGC section (km) | To assess $IC_{TRP}$, $OM_{TRP}$ and $OD_i$ (to calculate $OC_{TRP}$). | Fixed |
| **Generator data (for each generating unit)** | | |
| Plant type (integer input relating to row of matrix containing required plant type characteristic data) | To define BM costing, seasonal ranking order and seasonal mean availability assumptions of the generating unit. | Varied |
| TEC for scenario year (MW) | To carry out DCPF/DCOPF. | Varied |
| TEC for year of base case network (MW) | To carry out DCPF/DCOPF to assess $OC_{TRP}$. | Fixed |
| Bus number (integer of node) | To carry out DCPF/DCOPF. Note: for generating units with multiple network locations the unit TEC is split equally across nodes. | Varied |
| **Interconnector data (for each interconnector)** | | |
| Interconnector type (1 = separate external link, 0 = other external link) | To define the external links for separate treatment in defining import/export contributions. For the case studies in this thesis, interconnectors to Ireland are assumed to only export and are denoted as a 1. | Fixed |
| Line importing/exporting capability (MW) | To determine the interconnector import/export contribution. | Fixed |
| Inclusion for scenario year (1 = yes, 0 = no) | To include, if importing, the interconnector contribution to the generator data matrix and if exporting, to include the contribution to the bus data matrix, for carrying out a DCPF/DCOPF. | Varied |
| Inclusion for year of base case network (1 = yes, 0 = no) | To include the interconnector contributions as above for carrying out a DCPF/DCOPF to assess $OC_{TRP}$. | Fixed |
| Bus number (integer of node) | To carry out DCPF/DCOPF. | Fixed |
| Bid/Offer price (£/MWh) | To assess $CC_{SAV}$. | Fixed |
| **Plant type characteristic data (for each considered type of power station)** | | |
| Bid/Offer price (£/MWh) | To assess $CC_{SAV}$. | Fixed |
| Winter ranking order for scenario year (integer input) | To identify contributory generating units at ACS winter peak demand or determine unit outputs during the winter season (to calculate $CC_{SAV}$). | Varied |
| Summer ranking order for scenario year (integer input) | To determine unit outputs during the summer season (to calculate $CC_{SAV}$). | Varied |
| Summer ranking order for case study (integer input) | To identify contributory generating units for the median summer minimum demand value of the case study (to calculate $OC_{TRP}$). This ranking order represents the summer seasons from the year of the base case network to the scenario year. | Varied |
| Winter/Summer mean availability (%) | To assess $CC_{SAV}$. | Fixed |
| Probability distribution type (1 = binomial, 2 = normal, 3 = triangular) | To determine which type of probability distribution to create around the seasonal mean availability of the plant type for the assessment of $CC_{SAV}$. | Fixed |

**Table 4-6 Inputs for the MOTREP Framework**

| Input | Function | Fixed/Varied in Case Studies |
|---|---|---|
| Standard deviation of normal probability distribution (for associated plant types) | To create a normal distribution for allocated plant types in the assessment of $CC_{SAV}$. | Fixed |
| Minimum and maximum availabilities for triangular distribution (for associated plant types) | To create a triangular distribution for allocated plant types in the assessment of $CC_{SAV}$. | Fixed |
| **Electrical demand** | | |
| ACS peak demand for scenario year (MW) | To set scenario generating unit outputs, determine thermal issues in the base case network for the creation of TRPs or set nodal demand during the winter and summer season using a LDC (to calculate $CC_{SAV}$). | Varied |
| Percentage zonal demand distribution (matrix in the form of the example in Figure 4-1) | To calculate nodal demand in the network at ACS peak demand, median summer minimum demand and during the winter and summer season using a LDC. | Fixed |
| Median summer minimum demand for the case study (MW) | To assess $OC_{TRP}$. | Varied |
| Winter/Summer LDC | To assess $CC_{SAV}$. | Fixed |
| LDC time step (hours) | To define the duration of demand blocks used to estimate the seasonal LDC for the calculation of $CC_{SAV}$. | Fixed |
| **Limits for the creation of a reinforcement plan** | | |
| Max and min limits for $PFC_{MAX}$ (%) | To define the search space for the location of reinforcements within a TRP. | Fixed |
| Max and min limits for $PFC_{LINE}$ (%) | To define the search space for the capacity of reinforcements within a TRP. | Fixed |
| ROW constraint (integer input of 2,3 or 4) | To define the search space for the configuration of reinforcements within a TRP. | Fixed |
| **Additional inputs for transmission planning objectives** | | |
| Costs for OHL/UGC single-circuit and double-circuit additions (£/MVA.km or £/km) | To assess $IC_{TRP}$. | Fixed |
| Costs for OHL single-circuit and double-circuit upgrades (£/MVA.km) | To assess $IC_{TRP}$. | Fixed |
| OHL upgrade adjustment factor (£/km) | To adjust OHL single-circuit/double-circuit upgrade cost coefficient to assess $IC_{TRP}$. | Fixed |
| Gradient and y-intercept of the trend for $LL_{SAV}^{YEAR}$ | To assess $LL_{SAV}^{YEAR}$. | Fixed |
| O&M costs for OHL/UGC line addition at each voltage level (£/circuit-km) | To assess $OM_{TRP}$. | Fixed |
| Rate of line upgrading for OHL/UGC sections (circuit-km/week) | To calculate $OD_i$ for the assessment of $OC_{TRP}$. | Fixed |
| Outage duration for line addition (integer input - weeks) | To calculate $OD_i$ for the assessment of $OC_{TRP}$. | Fixed |
| Average TNUoS tariffs for the case study (two column matrix detailing the generation zone and £/kW tariff) | To calculate $TNUoS_{WKj}$ for the assessment of $OC_{TRP}$. | Fixed |
| Number of outage groups (integer input) | To equally split planned network outages to implement a TRP for the assessment of $OC_{TRP}$. | Varied (also varied in Appendix A.2.) |

## Table 4-6 Inputs for the MOTREP Framework

| Input | Function | Fixed/Varied in Case Studies |
|---|---|---|
| Summer availability parameters for onshore/offshore wind, wave and tidal generation (%) | For direct scaling of these generating unit types for application of the PTC method in the assessment of $OC_{TRP}$. | Fixed |
| Number of network congestion simulations (integer input) | To define $lim$ in the assessment of $CC_{SAV}$. Note: the number of simulations must be a factor of 10 to adhere to the number of correlated availabilities obtained in batches from the triangular distribution for wind generating units. | Fixed (varied in Appendix A.3.) |
| Length of summer outage season (integer input - weeks) | To define the length of the Summer Outage season and therefore the remaining Summer season for the assessment of $CC_{SAV}$. | Fixed (varied in Appendix A.3.) |
| Line outages during summer outage season (array of row indices analogous to the desired line in the branch matrix) | To alter the line status in the branch data matrix from in-service to out-of-service during the Summer Outage season for the assessment of $CC_{SAV}$. | Fixed |
| Number of LDC demand blocks (integer input) | To define the number of blocks used to estimate the seasonal LDC for the calculation of $CC_{SAV}$. | Fixed (varied in Appendix A.3.) |
| Distances (in km) between the central points of each generation zone (matrix in the form of Table B-1 in Appendix B). | To generate wind farm output correlations between each zone for the calculation of $CC_{SAV}$. | Fixed |
| **SPEA2** | | |
| Population size (integer input) | To define the size of the initial population ($P_t$) and newly generated populations ($P_{t+1}$). | Varied |
| Archive size (integer input) | To define the size of the final set of non-dominated solutions ($A_F$). Note: the archive size must not be greater than the population size. | Varied |
| Number of generations (integer input) | To define the number of generations allowed for the SPEA2 to evolve the TRP solutions of $P_t$. | Varied |
| Crossover type (1 = single point, 2 = double point, 3 = uniform) | To define the method used for crossover. | Fixed |
| Crossover probability | To define the rate of crossover. | Fixed |
| Mutation probability type (1 = constant, 2 = dynamic) | To define the type of probability used for mutation. | Fixed |
| Mutation probability | To define the rate of mutation. | Varied |
| Mutation route (1 = Route 1, 2 = Route 2) | To define whether TRPs need to achieve a $CC_{SAV} \geq 0$ to be included in the evolved population (Route 1) or whether TRPs can be included directly (Route 2). | Varied |
| **Security testing of reinforcement plans** | | |
| Circuit exclusion for N-1 contingency analysis (array of row indices analogous to the desired circuit in the branch matrix) | To exclude circuits from N-1 contingency analysis that result in electrical islanding of the base case network when their status is altered to out-of-service. | Fixed |
| Circuit exclusion for N-D contingency analysis (array of row indices analogous to the desired circuit in the branch matrix) | To define circuits that are to be excluded in the N-D contingency analysis. This could be due to electrical islanding issues and/or the exclusion of double-circuits to match criteria in the NETS SQSS). | Fixed |
| Line inclusion for N-2 contingency analysis (array of row indices analogous to the desired circuit in the branch matrix) | To define critical circuits that are to be included in the N-2 contingency analysis. | Fixed |

**Table 4-6 Inputs for the MOTREP Framework**

| Input | Function | Fixed/Varied in Case Studies |
|---|---|---|
| Network dividing generation zone (integer input) | To separate the transmission system into two contiguous parts for the application of the Boundary Allowance. | Fixed |
| **Setting scenario generating unit outputs** | | |
| De-rated capacity margin for wind/marine TEC (%) | To calculate the plant margin of the scenario. | Fixed |
| High, medium and low availability parameters for the application of the EPTC method (%) | To directly scale chosen plant types for the economy criterion. | Fixed |
| Plant types to be scaled by the highest/medium/lowest availability parameter (array of plant types analogous to the rows of the plant type characteristic data matrix). | To apply the EPTC method. | Fixed |

## 4.11. *Chapter 4 Summary*

In this chapter the design of the MOTREP framework for analysing future energy scenarios in the GB network is presented. The motivations for designing a flexible, systematic framework for scenario analysis which adequately considers the multi-objective problem of transmission planning for a large-scale multi-voltage network are introduced in Chapter 1 and discussed further in Chapter 2. Chapter 3 highlighted the need and current lack of a modelling framework to adequately evaluate the full spatial economic impact of a scenario to the GB electrical transmission network. This chapter details the design of the modelling framework implemented to achieve these goals.

In the first part of the chapter a description of the process used to define the inputs for the framework to create the scenario generation mix is included. Then the methods used to define nodal demand and scenario-related generating unit outputs are outlined. Further, the suitability of using a DCPF and DCOPF within the framework to simulate active power flows in the GB transmission network is discussed. This topic is examined further in Chapter 6, where the effect of excluding voltage constraints and reactive power flow for scenario analysis is discussed.

In the second part of the chapter, the design of the modelling framework to generate reinforcement plans for the initial population where each TRP consists of a unique set of reinforcements is presented. Further the methods used to calculate the objectives chosen for transmission planning are detailed. The combination of the framework design and the objective evaluations employed enables the exploration of trade-offs that better reflect the reality of the transmission planning problem in comparison to previous modelling approaches. In particular, the economic trade-off between alleviating annual network congestion and the capital investment cost of the reinforcement plan.

In the third part of the chapter, the use of the SPEA2 meta-heuristic to explore the search space of possible solutions, through population evolution, for the transmission planning problem is described. The reasons for choosing the SPEA2 are divulged and the implementation of each step of the SPEA2 is explained. In addition, the reasons behind the choice of each one of the parameters of the SPEA2 are discussed. Finally, the process used to define the network security and reliability performance of the non-dominated reinforcement plans generated by the SPEA2 is described.

In the next chapter the MOTREP framework is demonstrated against three case studies; a scenario for the year 2020 (Gone Green), and two scenarios for the year 2035 (Market Rules and Central Co-ordination).

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# Chapter 5

# 5. Future Energy Scenario Case Studies

## 5.1. *Introduction*

In the last chapter, the design of the MOTREP framework for the spatial economic assessment of a future energy scenario's impact on the GB transmission network was extensively discussed. A large range of scenario related studies, which envision the continuation of a centralised power system, can be carried out by the framework. In this chapter the MOTREP framework is demonstrated with three published case studies that are recent examples of future energy scenarios for the GB system.

In the first case study, the proposed modelling approach is applied to analyse the Gone Green scenario for the year 2020. This case study is used to compare cost savings of the optimal reinforcement plans generated by the framework against cost savings assessed by the GB SO, from solutions created by the GB TNOs for a similar scenario. This is to test the suitability of the solutions generated by the modelling approach and the framework itself, and to demonstrate the value of multi-objective optimisation to the transmission planning problem. Results for this case study illustrate the robustness and value of the modelling approach proposed to evaluate the network related impact of an energy scenario.

The second and third case studies relate to scenarios with different generation mixes for the year 2035. Results from both case studies demonstrate the use of the flexible modelling approach for scenario assessment and the value of the approach adopted in providing feedback on the likelihood from a network perspective of each scenario being adopted. The results from all three case studies expand current knowledge on the economic effect from a network perspective of varying penetrations and types of renewable and conventional generation, and in reducing electrical demand.

Chapters 2 and 3 detailed the ethos of the associated narratives for the scenarios used as case studies in this thesis. Hence only quantitative information on the case studies is included in this chapter.

## 5.2. *Base Case Transmission Network*

The network chosen for all case studies in this thesis, to represent the base case for scenario-related reinforcement, is the 2014/15 GB transmission network. This base case network has been chosen to match the analysis carried out by the GB SO and TNOs for the 2009 and 2011 Gone Green scenario [5.1]-[5.2]; allowing for a comparison to be made to the results generated by the MOTREP framework for the first case study. This network includes reinforcements that have already been consented and are either under construction or have recently been completed (as outlined in Chapter 1); such as the Beauly to Denny line upgrade. The 2014/15 network consists of 911 network nodes and 1065 transmission lines (excluding those under construction), 22,688km of which are OHLs and 975km are UGCs.

The network data required for the MOTREP framework is obtained from [5.3]. This consists of branch data, bus data and route length data. The resistance and reactance values of the lines were converted into per unit values with a system wide power base of 100MVA. The seasonal capacity limit obtained for each circuit in the network is the post-fault continuous rating (in MVA) [5.3]. This is the maximum continuous rating, restricted to a maximum 24-hour period, of a circuit appropriate to the season which may be applied in a fault situation until pre-fault requirements can be restored. The pre-fault capacity limit is the maximum continuous rating of a circuit without time limitation [5.4].

The selection of the upper limit for the maximum power flow condition ($PFC_{MAX}$) – used to generate reinforcement solutions in the MOTREP framework – is dependent upon the seasonal capacity limit used in the base case network. A pre-fault rating of around 84% of the post-fault continuous rating is believed to be suitable to restrict the risk of exceeding line temperature to a suitable value [5.5]. Hence in this case the upper limit of $PFC_{MAX}$ should be set to a minimum of 84% to satisfy the EPTC (see section 4.5 in Chapter 4). If pre-fault ratings are used in the base case network, then the upper limit of $PFC_{MAX}$ should be set to a minimum of 100% (again to satisfy the EPTC). As mentioned previously, both the upper limits of $PFC_{MAX}$ and $PFC_{LINE}^{Max}$ (the power flow condition of a line) in the MOTREP framework have been set to 84% for the case studies in this thesis.

## 5.3. Year 2020 *Case Study: Gone Green Scenario*

The Gone Green scenario used for this case study was created in 2011 by National Grid [5.6]. Table 5-1 below details the transmission connected generation mix of the Gone Green scenario and the UK mix in 2011/12 for comparison. The key changes of the Gone Green scenario by 2020 from 2011/12 are:

- A decrease of 49.5% in coal plant capacity due to age and forced closure (through plant opting out of the IED);
- An increase of around 20% in gas plant capacity caused by 11.8GW of new conventional CCGT capacity (at new locations). This more than compensates for the loss of 5.5GW of CCGT capacity as a result of the assumption that existing gas generating units will close at around 25 years of age;
- An increase of 22.6GW in total transmission connected wind capacity up to 25.7GW in 2020;
- An increase of around 18% in nuclear plant capacity due to the connection of two new nuclear EPR power plants (totaling 3.3GW) to compensate for the closure of two nuclear magnox plants. All nuclear AGR plants running in 2011/12 are assumed to receive a 10-year life extension; and
- An increase in the import potential of interconnectors to Europe from 1988MW through the interconnector to France, to 5588MW due to the addition of an interconnector to the

**Table 5-1 Gone Green Scenario Generation Mix for the year 2020**

| Generator Type | Year 2011/12 (GW) | Year 2020 (GW) |
|---|---|---|
| Coal | 28.80 | 14.55 |
| Gas | 29.60 | 35.51 |
| Nuclear | 10.41 | 12.32 |
| CHP | 2.07 | 2.24 |
| Oil | 3.64 | 0 |
| Onshore Wind | 2.13 | 9.15 |
| Offshore Wind | 1.00 | 16.56 |
| Hydro | 1.11 | 1.12 |
| Biomass | 0.05 | 1.04 |
| Marine | 0 | 0.96 |
| Pumped Storage | 2.74 | 2.74 |
| Imports | 1.99 | 5.59 |
| **Total Supply** | **83.54** | **101.8** |
| **ACS Peak Demand (including losses, excluding plant demand and exports)** | **58.6** | **59** |

Netherlands (rated at 1.2GW), Belgium (rated at 1GW) and Norway (rated at 1.4GW). All interconnectors are expected to support bi-directional flow.

The sizes, selections and locations of generating units and interconnectors needed to create the generation mix for the scenario year and year of the base case network (using the method detailed in section 4.2. of Chapter 4), are detailed in Appendix C.1. Figure 5-1 details the resulting distribution of transmission connected generation capacity for each generator type across the three TNO regions of the GB network; NGET's area has been split into a north region (from generation zone 9 to 13, see Figure 4-1 in Chapter 4) and south region (below generation zone 13). The majority of generation capacity in SHE-T's area is predicted to be wind. Gas generation is predicted to continue to significantly contribute to overall generation capacity in NGET's area (both north and south). Also, due partly to the predicted closure of several coal plants (through opting out of the IED), a significantly greater proportion of transmission connected capacity in the south of England and Wales is predicted to be offshore wind rather than coal; 3GW extra of offshore wind generation is predicted to connect. Also,

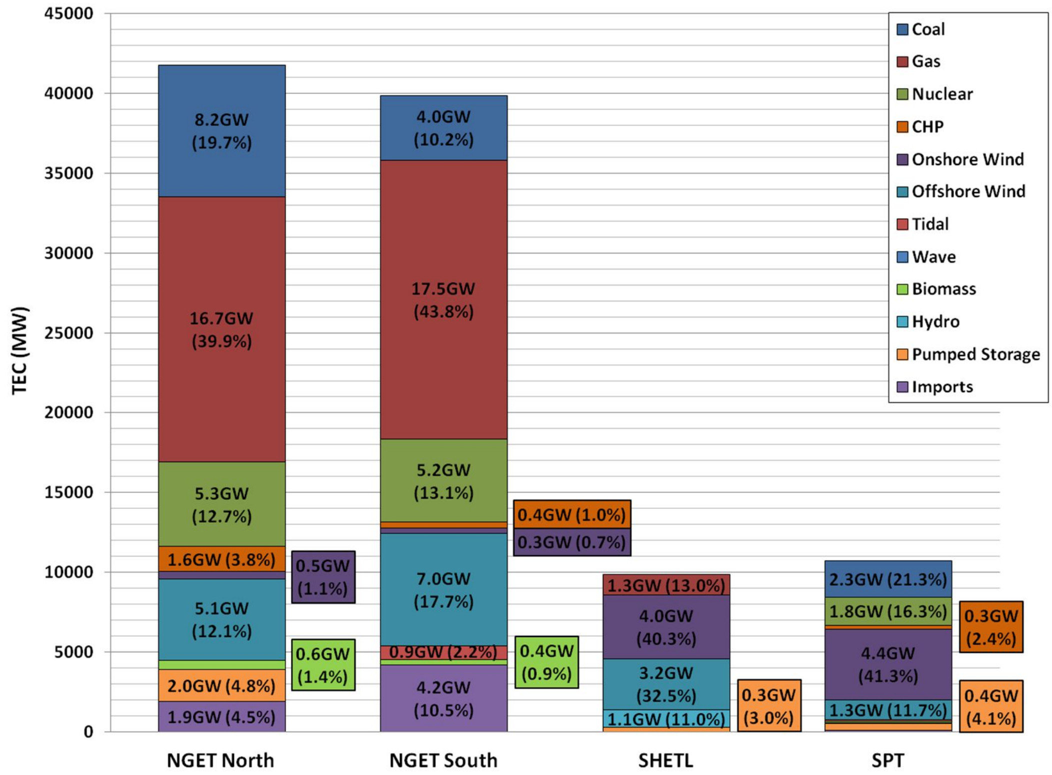


**Figure 5-1 Distribution of transmission connected generation TEC across the GB network for the Gone Green scenario in the year 2020**

most transmission connected onshore wind generation in the UK is predicted to be located in Scotland, with a total TEC of 8.4GW.

A stipulation of the Gone Green 2011 scenario is that a de-rated capacity margin of 5% for TEC from wind is used to calculate the plant margin [5.2]. As supply exceeds the assumed ACS peak demand of the scenario (as shown in Table 5-1) by 42.8GW, this de-rated capacity margin can be accommodated by the scenario (considering the total capacity of wind generation). A de-rated capacity margin for marine TEC has not been stipulated in the scenario and as such a 100% capacity margin is assumed. For calculating the outage cost of a reinforcement plan, summer season availability parameters of 27.9% and 37.5% (obtained from [5.7]) were used for onshore and offshore wind generating units respectively to apply the adapted planned transfer condition (PTC).

As transmission connected marine generation is in its infancy, the expected availability of a large-scale marine generator (wave or tidal) is unclear. Small scale examples currently exist such as the SeaGen 1.2MW tidal turbine, deployed in 2008 and located in Northern Ireland's Strangford Lough, which reportedly achieved a capacity factor of 66% in the first year of operation [5.8]. However, until a capacity factor can be obtained which represents the average of many individual units, a reliable availability parameter cannot be obtained. Hence the summer season availability parameter for TEC from both wave and tidal is assumed to be 100% and the output of these units is thus scaled down within the framework using the scaling factor (see section 4.5.2.).

**Table 5-2 Gone Green Scenario Generator Type Ranking Order (source [5.9])**

| Generator Type | Rank |
|---|---|
| CHP | 1 |
| Base CCGT | 2 |
| Onshore Wind | 3 |
| Nuclear | 4 |
| Hydro | 5 |
| Biomass | 6 |
| Offshore Wind | 7 |
| Wave | 8 |
| Tidal | 9 |
| Base Coal | 10 |
| Marginal CCGT | 11 |
| Marginal Coal | 12 |
| Pumped Storage | 13 |
| OCGT | 14 |

The generator type ranking order used for the Gone Green scenario – to enable the identification of contributory generating units within the framework for the application of the EPTC – is detailed in Table 5-2. Although different representative ranking orders can be used in the framework, the same ranking order is used for both winter and summer seasons of the scenario year, to calculate the annual constraint cost saving of a reinforcement plan, and as the summer ranking order for the case study, to represent the summer seasons in the calculation of outage cost.

The median summer minimum demand value used to evaluate the outage cost of a TRP for the Gone Green scenario is 22.54GW. This value was determined as the midpoint between the minimum demand value of the base case network (22711MW) and the minimum demand value of the scenario (22370MW) – calculated by applying the ratio of peak demand to minimum demand from the 2014/15 base case network (59900MW peak and 22711MW minimum demand) to the ACS peak demand of the scenario (59GW). The number of outage groups used (as per the defined general rule) for the Gone Green scenario is 10. Hence two outage groups would need to be accommodated by the GB network per year from 2015 until 2019.

Following the identification of contributory generating units at scenario peak demand, the application of the EPTC and a DCPF, 39 thermal limit violations above the most onerous power flow condition (an 84% $PFC_{MAX}$) were discovered by the MOTREP framework. These thermal violations are detailed in Table 5-3. This represents the minimum number of thermal violations that the framework identified a transmission reinforcement plan to alleviate. Each thermal violation is allocated a generation zone (of the form detailed in Figure 4-1) based on the "from" end bus (or network node). Most thermal violations occur on circuits operating at 132kV, which have a low capacity and are not significantly long in length. Zones 1 (north of Scotland), 5 (west of Scotland's central belt), 7 (south of Scotland) and 9 (north west of England) all contain several thermal violations. Zones 7 and 9 have thermal violations occurring across significant circuits operating at 400kV.

Coupled with the ever-present southerly power flow from Scotland to the south of England, the network in zone 7 for the Gone Green scenario needs to accommodate an increase in generation capacity from the base case year of 897MW in onshore wind (totalling 3928MW), and a 450MW offshore wind farm. Hence thermal limit violations can be expected in this zone.

**Table 5-3 Thermal limit violations above an 84% $PFC_{MAX}$ resulting from the EPTC for the Gone Green Scenario**

| Zone | fbus | tbus | No. of Lines | OHL (km) | UGC (km) | Voltage (kV) | Capacity (MVA) | Thermal Violation (%) |
|---|---|---|---|---|---|---|---|---|
| 1 | 61 | 499 | 1 | 51.5 | 0.0 | 275 | 525 | 85.0 |
| 1 | 40 | 605 | 1 | 30.9 | 0.0 | 132 | 132 | 119.3 |
| 1 | 604 | 730 | 1 | 31.2 | 0.0 | 132 | 132 | 84.9 |
| 1 | 40 | 604 | 1 | 30.9 | 0.0 | 132 | 126 | 142.0 |
| 1 | 605 | 730 | 1 | 31.2 | 0.0 | 132 | 126 | 104.8 |
| 1 | 40 | 439 | 1 | 15.4 | 0.0 | 132 | 126 | 94.8 |
| 1 | 40 | 440 | 1 | 15.4 | 0.0 | 132 | 126 | 94.8 |
| 1 | 471 | 353 | 1 | 41.3 | 0.0 | 132 | 126 | 85.9 |
| 1 | 607 | 811 | 1 | 16.1 | 0.0 | 132 | 126 | 85.0 |
| 1 | 514 | 730 | 1 | 10.5 | 0.0 | 132 | 111 | 86.4 |
| 5 | 187 | 423 | 1 | 0.0 | 41.0 | 132 | 194 | 109.8 |
| 5 | 188 | 424 | 1 | 0.0 | 41.0 | 132 | 194 | 109.8 |
| 5 | 185 | 187 | 1 | 0.0 | 1.0 | 132 | 194 | 109.8 |
| 5 | 186 | 188 | 1 | 0.0 | 1.0 | 132 | 194 | 109.8 |
| 5 | 17 | 5 | 1 | 9.9 | 0.0 | 132 | 92 | 119.0 |
| 5 | 681 | 6 | 1 | 14.2 | 0.0 | 132 | 92 | 102.1 |
| 5 | 680 | 5 | 1 | 14.4 | 0.0 | 132 | 92 | 100.0 |
| 7 | 375 | 376 | 1 | 41.7 | 0.0 | 400 | 1910 | 108.7 |
| 7 | 282 | 592 | 1 | 23.4 | 0.0 | 400 | 1910 | 108.7 |
| 7 | 257 | 824 | 2 | 34.3 | 2.2 | 400 | 1250 | 114.7 |
| 7 | 270 | 866 | 1 | 0.0 | 6.0 | 275 | 457 | 90.7 |
| 7 | 422 | 423 | 1 | 0.0 | 3.5 | 132 | 194 | 109.8 |
| 7 | 422 | 424 | 1 | 0.0 | 3.5 | 132 | 194 | 109.8 |
| 7 | 236 | 447 | 1 | 7.9 | 3.4 | 132 | 110 | 90.3 |
| 7 | 237 | 448 | 1 | 7.9 | 3.4 | 132 | 110 | 90.3 |
| 7 | 447 | 823 | 1 | 0.0 | 1.1 | 132 | 110 | 90.3 |
| 7 | 448 | 823 | 1 | 0.0 | 1.1 | 132 | 110 | 90.3 |
| 8 | 114 | 184 | 1 | 13.5 | 0.0 | 132 | 320 | 86.1 |
| 8 | 115 | 184 | 1 | 13.5 | 0.0 | 132 | 320 | 86.1 |
| 9 | 470 | 674 | 1 | 43.5 | 0.0 | 400 | 2210 | 85.4 |
| 9 | 392 | 403 | 1 | 10.2 | 0.0 | 400 | 2010 | 108.8 |
| 9 | 392 | 375 | 1 | 9.9 | 0.0 | 400 | 2010 | 108.8 |
| 9 | 403 | 430 | 2 | 81.9 | 0.0 | 400 | 1390 | 111.3 |
| 9 | 430 | 686 | 1 | 34.5 | 0.0 | 400 | 1390 | 104.4 |
| 9 | 235 | 822 | 1 | 43.6 | 0.0 | 132 | 132 | 104.4 |
| 9 | 356 | 821 | 1 | 33.2 | 0.0 | 132 | 132 | 90.4 |
| 10 | 512 | 810 | 1 | 7.4 | 0.3 | 400 | 1590 | 103.1 |
| 13 | 130 | 470 | 1 | 13.4 | 0.0 | 400 | 2210 | 85.4 |
| 14 | 526 | 737 | 1 | 0.0 | 1.5 | 132 | 500 | 140.0 |

However, in zone 9 a reduction in coal and gas generation capacity from the base case year is observed for the Gone Green scenario; a reduction of 5243MW (through the closure of Drax and Ferrybridge) and 1794MW (through the closure of Killingholme 1&2 and Roosecote) respectively. A total capacity of 1500MW of offshore wind (from Dogger Bank and Hornsea) is to connect in zone 9 to match the generation mix of the Gone Green scenario, however the location of the connection is near to the sites of Killingholme and Drax on the east coast. The location of most thermal violations in zone 9 is on 400kV double-circuit lines on the west coast.

Two corridors east and west currently exist in the GB transmission network for carrying power from Scotland to England. Thermal limit violations are apparent on the west coast corridor in zone 9 as a result of the increased generation capacity (mainly from onshore and offshore wind) in SHE-T and SPT's area. Further, the thermal violations observed in zone 10 (north east of England) occur across key circuits on the east corridor. The 2014/15 base case network, which includes reinforcements to up-rate the transmission capacity between Scotland and England and the north of England, cannot accommodate the southerly power flow which results from the Gone Green scenario (developed in 2011) for the year 2020. Further network reinforcement is therefore still required.

### 5.3.1. Case Study 1: Results and Discussion

The parameters used in the SPEA2 optimisation for this case study are shown in Table 5-4. Through utilising parallel computation in the calculation of annual constraint cost saving for each generated solution, the evaluation of a TRP took an average of 9.72 seconds[11] (for 100 DCOPF calculations in the evaluation of $CC_{SAV}$ and the use of 10 outage groups in the evaluation of $OC_{TRP}$) and the total evaluation time for 200 generations was 65 hours.

The framework nondominated multi-objective results for the Gone Green scenario are shown in the bi-objective plot in Figure 5-2. The Pareto front is a plane in the three-dimensional space of objective evaluation, and so each one of the plots corresponds to the projection of this plane on a bi-dimensional axis. It was found that no nondominated, Pareto-optimal TRP solutions

**Table 5-4 Case Study 1 Parameters for SPEA2 Optimisation**

| | |
|---|---|
| **Population size** | 120 |
| **Archive size** | 80 |
| **Generations** | 200 |
| **Crossover type** | Uniform |
| **Crossover probability** | 0.9 |
| **Mutation type** | Constant Rate |
| **Mutation probability** | 0.4 |
| **Mutation route** | 1 |

[11] Evaluation time is based on the use of a 64-bit version of Matlab and a quad core, octo thread Intel i7-2600 3.4GHz central processing unit.

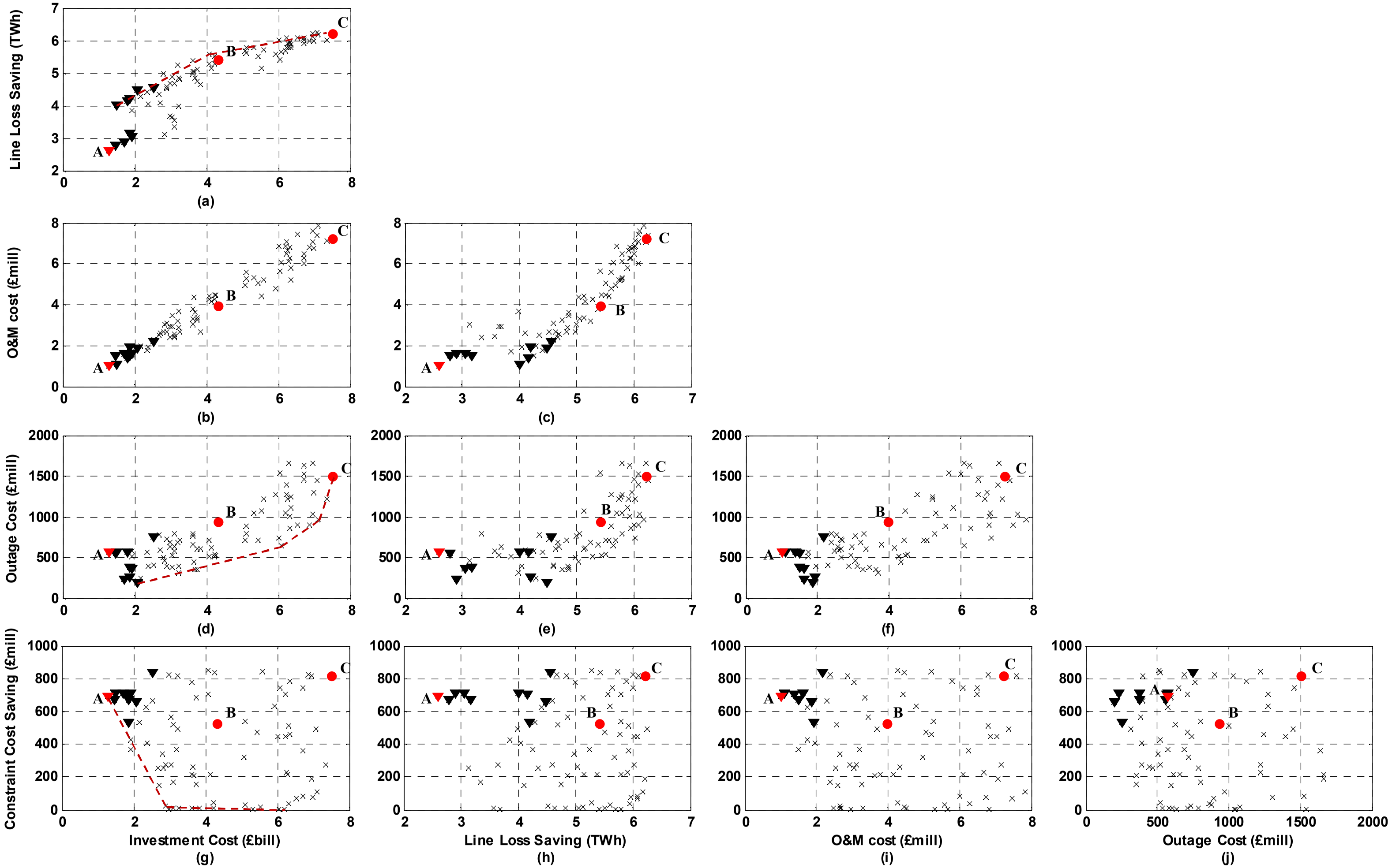


Figure 5-2 MOTREP framework nondominated multi-objective results for the Gone Green scenario in 2020

generated by the SPEA2 failed the security test (as detailed in section 4.9.). Hence all archived TRP evaluation results were included in the final output of the framework.

Three solutions generated from the framework are highlighted (using a red dot) in Figure 5-2. These are TRP solutions with an associated minimum (**solution A**), medium (**solution B**) and maximum (**solution C**) level of investment cost. Table 5-5 details the configuration and objective evaluations of these three solutions. Generally, a low capital cost solution has line upgrades (UPG) as the significant component and often largest single component compared to single-circuit additions (SCA) or double-circuit additions (DCA). **Solutions A and B** predominantly consist of line upgrades, with upgrades accounting for 43.4% and 38.5% respectively of all reinforcements in the plan; only 27.8% of all reinforcements in **solution C** involve reconductoring. Further, as the Gone Green scenario resulted in 39 thermal limit violations on the base case network for the most onerous power flow condition, it is evident that many reinforcements in **solution B and C** (in particular) caused exacerbation of the original network constraints, and the solution needed to be significantly redesigned within the framework. Hence, an increased number of reinforcement components were required.

As the number of DCAs, SCAs or UPGs in **solution A** is less than the number of thermal limit violations present in the base case network, and a combination of reinforcements adhering to a right-of-way of 4 is possible, then it's likely that the reinforcements in **solution A** have a more adequate capacity, configuration and location for the base case network problem. Thus, the overall route length of the circuits requiring reinforcement for **solutions B and C** is over

**Table 5-5 Configuration and Objective Evaluations of TRP Solutions A, B and C**

| | TRP A | TRP B | TRP C |
|---|---|---|---|
| No. of circuits (DCA / SCA / UPG) | 21 / 26 / 36 | 65 / 63 / 80 | 110 / 118 / 88 |
| Total OHL / UGC route length to be reinforced (km) | 1099.5 / 110.26 | 3066.5 / 134.67 | 4619.4 / 253.15 |
| Maximum reinforcement capacity (MVA; type; generation zone) | 2942; UPG; 9 | 3812; UPG; 14 | 3779; UPG; 9 |
| Maximum Line Loading (%) – At winter peak under the EPTC | 82.85 | 83.84 | 83.52 |
| Mean Line Loading (%) – At winter peak under the EPTC | 27.24 | 25.24 | 24.60 |
| $IC_{TRP}$ (£billion) | 1.28 | 4.33 | 7.51 |
| $CC_{SAV}$ (£million) | 691.41 | 523.95 | 815.75 |
| $OC_{TRP}$ (£million) | 572.11 | 934.63 | 1499.7 |
| Incremental O&M cost (£million) | 1.03 | 3.97 | 7.22 |
| $LL_{SAV}^{YEAR}$ (TWh) | 2.60 | 5.42 | 6.22 |

2.8 times and 4.2 times the overall OHL route length of **solution A** respectively, as well as 1.2 times and 2.3 times the overall UGC route length.

The maximum capacity of the reinforcements employed in each solution occurred at a location in generation zone 9 for **solutions A and C**, and zone 14 for **solution B**. As only one thermal violation exists in zone 14 and it occurs on the 132kV network, then the size of the upgrade applied in this case is a clear example of a TRP redesign carried out by the framework to alleviate exacerbated thermal constraints that have resulted from the original reinforcement proposal. The effect of the three solutions on the objective evaluations for $IC_{TRP}$, $OC_{TRP}$, incremental O&M cost and $LL_{SAV}^{YEAR}$ is evident in Table 5-5. As the level of reinforcement increases in a solution, and the number of circuit additions rises, then the level of the respective objectives increases.

By carrying out a trade-off analysis on the nondominated results of the framework, it is clear from Figure 5-2(a) that by increasing network investment cost from £1.28billion to £7.51billion (improving overall network capacity and capability), annual line losses can be reduced by 3.62TWh; equating to an annual saving of £216.95million when using an energy cost of £60/MWh (a conservative cost of future energy between 2015 and 2029 [5.1]). The annual incremental O&M cost of a TRP is found to conflict with this trend (see Figure 5-2(b)) and increase with greater network investment from £1.03million to £7.22million (this can also be seen in Figure 5-2(c)), as does the trend for outage cost in Figure 5-2(d), which generally increases from £198.47million to £1.66billion; though the trend in Figure 5-2(d) is convex in nature, in comparison to the more linear trend in Figure 5-2(b) and quadratic trend in Figure 5-2(a).

The resulting convex and quadratic nature of the outage cost and annual line loss saving objectives respectively can be analysed further as a result of the multi-objective analysis, and by carrying out a more detailed trade-off analysis, additional conclusions can be formed. In Figure 5-2(a) and Figure 5-2(d) an estimation of the Pareto front has been included. From an investment cost of £1.50billion to £4.08billion, annual line losses can be reduced by 1.57TWh at a rate of 0.61GWh per £1million. However, from £4.08billion to £7.51billion, annual line losses can only be reduced by 0.65TWh at a lower rate of 0.19GWh per £1million. Hence the line loss saving able to be achieved from the combined network (i.e. base case and TRP) at this level of expenditure is approaching saturation, with a peak of around 6TWh. For the case of network outages, from an investment cost of £2.07billion to £6.08billion, outage costs increase by £449.73million at a rate of £112k per £1million of network investment. However, from £6.08billion to £7.10billion, and from £7.10billion to £7.51billion, outage costs increase by £322.39million and £529.11million at a greater rate of £317k and £1,292k per £1million of network investment respectively. This is the result of an increased usage of SCAs and DCAs in reinforcement solutions which require a greater level of network investment.

Overall it can be deduced that with each additional £1million expenditure on the onshore network, from an initial outlay of £1.28billion, further upfront costs for network outages are likely to increase up to a rate of £1,292k per £1million, and the incremental savings in reducing annual line losses is likely to decrease, down to a rate of £11.4k per £1million. In general, a further upfront cost of £235k for network outages could be required and an increased annual cost saving of only £34k (figure reduced slightly to consider the minimal increase in incremental O&M cost) from reducing line losses could be achieved. This annual cost saving is too low to justify further network expansion and it would take nearly 7 years for the estimated savings to recover the upfront outage cost.

For an investment cost of up to £4.08billion, from an initial outlay of £1.28billion, each additional £1million expenditure could require a more reasonable increased upfront cost of £112k for network outages and achieve an improved increased annual cost saving of £36k (again reduced slightly to consider the minimal increase in incremental O&M cost) from reducing line losses. In this case, it would take just over 3 years for the increased estimated savings to recover the further upfront outage costs. Hence according to the framework, network investment below £4.08billion is advised for the Gone Green scenario if the minimal solution for investment cost cannot be achieved. However, annual savings resulting from reducing constraint costs are more significant and this will influence the above conclusion.

As can be seen in Figure 5-2(g)-(j), the trade-offs involving annual constraint cost saving are less clear. In Figure 5-2(g) an estimation of the Pareto front has been included and this represents the envelope of the objective evaluations obtained, however many solutions occur at a significant distance away (in the objective space) from this envelope. This is due to the reality of the complex conflict between constraint cost and investment cost that the GB SO experiences. As the MOTREP framework includes a wide search space of reinforcement options and evaluates network constraints at numerous points across the year, the complexity of this conflict is considered. The MOTREP framework can create and utilise a wide range of reinforcement solutions at multiple locations (depending on the value of $PFC_{MAX}$) of varying type and line capacity, which results in network solutions that either alleviate network constraints across the whole year or alleviate congestion across only part of the year, and exacerbate constraints during, for example, the summer outage season.

By considering further the complexities of the transmission planning problem, beyond, for example, the work of Maghouli *et al.* [5.10]-[5.11] – where constraint cost was analysed at peak demand [5.11], or across several time steps around peak demand [5.10], and line addition of fixed capacity (from a pre-defined subset) was the only reinforcement consideration – TRP solutions requiring a similar investment cost can achieve a range of savings in annual constraint costs. Also, similar constraint cost savings can be achieved from a range of network infrastructure investments. As similar investments can also lead to varying evaluations of the other objectives as well, the SPEA2 can still treat solutions that result in lower savings in annual constraint cost, for the same investment cost, as being nondominated.

Other methods for crossover and mutation were tested as well as various crossover and mutation probabilities, archive sizes, population sizes and generation limits, but this did not aid the SPEA2 in defining a clearer trend in annual constraint cost savings. The nondominated TRP solutions shown in Figure 5-2 can achieve an annual constraint cost saving of between £186.6k (0.02%) and £848.41million (94%) from the original £903.84million constraint cost assessment of the base case network in 2020.

The constraint costs arising from the base case network are significant. The peak cost from the BM and associated quantity of constrained on/off generation output (arising from the DCOPF), for each season in the assessment of $CC_{SAV}$ for the base case network, is detailed in Table 5-6. It is evident that as demand increases from the summer to the winter season, network

**Table 5-6 Peak Seasonal Constraint Cost (per hour) of the 2014/15 Base Case Network under the Gone Green scenario in the year 2020**

| Season | Constrained On/Off (MW) | Constrained Off Cost | Constrained On Cost | Peak Constraint Cost |
|---|---|---|---|---|
| Summer Outage | 1,747.46 | £54,311.04 | £72,220.34 | £126,531.38 |
| Summer | 4,296.23 | £28,526.71 | £189,244.64 | £217,771.35 |
| Winter | 13,913.34 | £126,759.70 | £154,478.59 | £281,238.29 |

constraints become more common and the cost that results from the BM increases. The peak constraint cost for one hour in the winter season is around 129% and 222% of the peak constraint cost observed in the summer and summer outage seasons.

For the summer outage and winter seasons, the peak constraint cost occurs at the demand block with the peak demand value for the season; 28,936MW (plus 6,600MW of continental exports) and 56,217MW (plus 1,000MW of exports to Ireland) respectively. Considering the duration of each demand block (176 hours and 119 hours respectively) and the number of DCOPF simulations allocated to each season and therefore each demand block (the seasons are 1,344 hours and 3,623 hours in duration), the constraint cost for each time period equates to £7,423,200 and £33,467,356. For the summer season, the peak constraint cost occurs at a demand block with a demand value of 43,799MW (plus 6,600MW of continental exports); 88.25% of the peak demand block value for the season. This equates to a constraint cost for the time period (84.25 hours in this case) of £18,347,237.

Table 5-7 details the generating units above 100MW which are significantly constrained on/off by the DCOPF during the peak constraint cost period of the summer and summer outage seasons (the winter season has been excluded from the table due to the large number of generating units which are significantly constrained at the peak of the season). Note that generating units of different types occasionally share the same network connection point and in these instances the bid and offer price of the nodal TEC is calculated from the bid and offer prices of each generator type and the percentage contribution of each type to the total capacity. Also, note that the TEC of generator types which have a non-applicable offer price in Table 4-4 of Chapter 4, has been reduced to the output defined for the $CC_{SAV}$ assessment.

From Table 5-7 it is evident that significant alterations to the output of several large-scale generating units are required in the summer and summer outage seasons to alleviate base case network constraints and meet demand in 2020 for the Gone Green scenario. According to the DCOPF, given the seasonal generation outputs defined from various probability distributions (as detailed in Table 4-5 in Chapter 4), alterations in generation output are required even when demand is at its lowest in the summer outage season.

The alterations made by the DCOPF generally reflect the thermal violation problem of the base case network (as detailed in Table 5-3). Generation is generally constrained off in

**Table 5-7 Generating Units Constrained On/Off in the Summer and Summer Outage Seasons due to the 2014/15 Base Case Network under the Gone Green scenario**

| Generator Type | Node Name | Node No. | Zone | Voltage (kV) | Output (MW) | Assumed TEC (MW) | Constrained On/Off (+/- MW) |
|---|---|---|---|---|---|---|---|
| **Summer Outage Season** | | | | | | | |
| CCGT | PEHE20 | 657 | 2 | 275 | 1006.47 | 1180 | -557.95 |
| CCGT | BAGB20 | 35 | 15 | 275 | 1380.18 | 1422 | -134.24 |
| Onshore Wind | BEAU40 | 42 | 1 | 400 | 288.85 | 288.85 | -134.24 |
| CCGT | COSO40 | 167 | 17 | 400 | 1447.06 | 1640 | +192.94 |
| CCGT | GRAI40 | 367 | 17 | 400 | 1580.29 | 1990 | +409.71 |
| CCGT | LANG40 | 520 | 20 | 400 | 745.29 | 905 | +159.71 |
| CCGT | SEAB40 | 718 | 15 | 400 | 1016.24 | 1234 | +217.76 |
| Coal (30%) / CCGT (70%) | USKM20 | 837 | 15 | 275 | 825 | 1213 | +388 |
| **Summer Season** | | | | | | | |
| Coal (84%) / CCGT (16%) | COTT40 | 168 | 13 | 400 | 336.91 | 2395 | -336.91 |
| CHP | HUMR40 | 426 | 9 | 400 | 852.60 | 852.60 | -852.60 |
| Offshore Wind | KILL40 | 486 | 9 | 400 | 225.85 | 225.85 | -225.85 |
| CCGT | SHBA40 | 728 | 9 | 400 | 1171.62 | 1285 | -1171.62 |
| CCGT | STAY40 | 764 | 13 | 400 | 1550 | 1700 | -1550 |
| Coal (93%) / CCGT (7%) | ABTH20 | 4 | 15 | 275 | 104.49 | 1787.5 | +793.05 |
| CCGT | COSO40 | 167 | 17 | 400 | 1447.06 | 1640 | +192.94 |
| CCGT | DIDC40 | 218 | 18 | 400 | 1048.53 | 1550 | +501.47 |
| CCGT | GRAI40 | 367 | 17 | 400 | 1638.82 | 1990 | +351.18 |
| CCGT | LANG40 | 520 | 20 | 400 | 612.21 | 905 | +292.79 |
| CCGT (20%) / Offshore Wind (80%) | NORW40 | 635 | 14 | 400 | 599.04 | 734.92 | +135.88 |
| CCGT | PEMB40 | 663 | 15 | 400 | 1852.94 | 2100 | +247.06 |
| CCGT | SEAB40 | 718 | 15 | 400 | 1088.82 | 1234 | +145.18 |
| CCGT | SPLN40 | 758 | 13 | 400 | 1365.88 | 1720 | +298.43 |
| Coal (30%) / CCGT (70%) | USKM20 | 837 | 15 | 275 | 775 | 1213 | +438 |
| CCGT (73%) / Offshore Wind (27%) | WALP40 _EME | 841 | 13 | 400 | 3160.86 | 3667.5 | +506.62 |

generation zones where thermal violations exist (zones 1, 5, 7, 8, 9, 10, 13 and 14) and constrained on in generation zones where violations do not exist; specifically zones 15, 17, 18 and 20 (representing the South of England). Further, most generation which is constrained on is often from base load CCGT or Coal plant at the lowest offer price (as shown in Table 4-4 in Chapter 4). During the peak constraint cost period of the winter season, at a demand of 57,217MW (including 1,000MW of exports), all remaining generation from base load CCGT or Coal plants was constrained on by the DCOPF up to the TEC constraint, and as imports from the interconnectors was constrained off, generation from hydro and then marginal Coal and Gas plants was constrained on (often from an original output of zero). Hence, the DCOPF using the MIPS solver outputted an expected plan of generation dispatch given the cost data used; namely the bid and offer prices as detailed in Table 4-4 in Chapter 4.

As the chosen route for mutation is route one, each reinforcement plan in the nondominated set of solutions is required to achieve a saving in annual constraint costs from the base case network. From analysing the generating units which have been constrained on/off by the DCOPF for each reinforcement plan in the nondominated set, it was found that the most common seasonal constraint actions involved constraining off base load coal-fired generation at Cottam power station (network node COTT40), base load CCGT generation at Staythorpe (STAY40) and South Humberbank power stations (SHBA40) and generation from the CHP scheme in Immingham (HUMR40), and constraining on base load coal-fired generation at Longannet (LOAN20 / 544) and Fiddlers Ferry (FIDF20_SPM / 323) power stations, and base load CCGT generation at the Peterhead (PEHE20), Thames Haven (COSO40) and Grain (GRAI40) power stations. The ability to constrain on generation at Peterhead was often not possible for the base case network (as detailed in Table 5-7).

Although clear trade-offs involving annual constraint cost saving cannot be defined from the nondominated set of this case study (see Figure 5-2), top performing TRPs within the set can be located for the multi-objective problem, and a verdict can then be reached on the economic impact from the perspective of the transmission network, of the energy scenario. Several methods specific to the users' requirements could be used to evaluate a scenario from the framework's output. Policymakers may simply want to use an average value of the investment costs of the nondominated set. TNOs may simply want to locate a TRP with a low CAPEX and a high saving in annual constraint costs to increase the likelihood of regulatory approval via the GB SO CBA (as detailed in Chapter 2). For this case study the top performing TRPs have been located using a measure of payback period which considers the effect of all the considered transmission planning objectives in the framework. The payback period can be defined as the time to recover up-front costs of a TRP, post scenario year, through savings in annual costs (from line loss reduction and congestion relief) over the unreinforced network. This can be formulated as follows:

$$PB = \frac{IC_{TRP} + OC_{TRP} + \sum_{n=1}^{N}\left(\frac{OM_{TRP}}{N} \times n\right)}{CC_{SAV} + LL_{SAV}^{COST} - OM_{TRP}} \tag{5-1}$$

where $PB$ is the payback period in years; $LL_{SAV}^{COST}$ is the cost associated with $LL_{SAV}^{YEAR}$ (using £60/MWh [5.1]), and $N$ is the number of years from the base case network to the year before the scenario year (5 years for this study; 2015-2019). Hence an increasing linear trend in incremental O&M cost ($OM_{TRP}$) is assumed during the period of expected TRP construction.

The objective evaluations and configurations of the top ten nondominated TRPs with the lowest payback period are detailed in Table 5-8 and Table 5-9 respectively. Further, the top ten solutions have been highlighted (using a black triangle) in Figure 5-2. All 10 solutions have a payback period of less than 3 years, highlighting the significant economic saving that can be made from investing in the GB network at the right locations under this scenario. It is evident from Table 5-9 that the top performing TRP solutions – in line with the observations made for solutions A, B and C – consist, on the whole, of line upgrades (UPG) as the

**Table 5-8 Top Ten TRP Objective Evaluations for Gone Green according to Payback Period**

| TRP ID | $IC_{TRP}$ (£billion) | $CC_{SAV}$ (£million) | $OC_{TRP}$ (£million) | $OM_{TRP}$ (£million) | $LL_{SAV}^{YEAR}$ (TWh) | PB (years) |
|---|---|---|---|---|---|---|
| 1 | 1.50 | 715.00 | 572.95 | 1.11 | 4.00 | 2.17 |
| 2 | 1.28 | 691.41 | 572.11 | 1.03 | 2.60 | 2.19 |
| 3 | 1.70 | 711.11 | 232.95 | 1.63 | 2.90 | 2.20 |
| 4 | 1.46 | 673.64 | 559.59 | 1.50 | 2.78 | 2.41 |
| 5 | 2.07 | 656.13 | 198.47 | 1.86 | 4.48 | 2.47 |
| 6 | 1.79 | 707.92 | 563.32 | 1.38 | 4.16 | 2.47 |
| 7 | 1.92 | 709.67 | 372.84 | 1.62 | 3.05 | 2.58 |
| 8 | 1.85 | 675.28 | 375.80 | 1.50 | 3.17 | 2.59 |
| 9 | 1.85 | 535.26 | 253.84 | 1.94 | 4.20 | 2.68 |
| 10 | 2.54 | 835.58 | 751.11 | 2.18 | 4.56 | 2.97 |

**Table 5-9 Top Ten TRP Configurations for Gone Green according to Payback Period**

| TRP ID | No. of circuits (DCA / SCA / UPG) | Total OHL / UGC route length to be reinforced (km) | Maximum reinforcement capacity (MVA; type; generation zone) | Max Line Loading (%) | Mean Line Loading (%) |
|---|---|---|---|---|---|
| 1 | 28 / 22 / 36 | 1126.9 / 110.26 | 3670; UPG; 9 | 82.03 | 26.10 |
| 2 | 21 / 26 / 36 | 1099.5 / 110.26 | 2942; UPG; 9 | 82.85 | 27.24 |
| 3 | 28 / 32 / 35 | 1099.5 / 110.26 | 3465; UPG; 13 | 83.22 | 26.83 |
| 4 | 30 / 31 / 32 | 1099.5 / 110.26 | 3496; UPG; 7 | 83.88 | 27.09 |
| 5 | 34 / 34 / 30 | 1191.9 / 110.10 | 3554; SCA; 13 | 83.92 | 26.14 |
| 6 | 26 / 30 / 37 | 1126.9 / 110.26 | 3717; UPG; 9 | 83.56 | 26.01 |
| 7 | 28 / 34 / 35 | 1099.5 / 110.26 | 3601; UPG; 7 | 83.21 | 26.58 |
| 8 | 29 / 26 / 38 | 1099.5 / 110.26 | 3373; UPG; 13 | 82.21 | 26.65 |
| 9 | 38 / 33 / 36 | 1206.8 / 110.33 | 3681; DCA; 9 | 83.75 | 26.68 |
| 10 | 39 / 48 / 70 | 2368.7 / 120.95 | 3487; UPG; 7 | 83.90 | 25.39 |

significant component and often largest single component compared to single-circuit additions (SCA) or double-circuit additions (DCA).

Many of the solutions produced by the MOTREP framework require many upgrades and line additions to the onshore network, particularly over a five-year period. This may seem unrealistic or may reflect the lack of surplus capacity in the base network; however, most TRPs have been produced to improve GB network thermal security for the purposes of enabling additional generation to connect after the scenario year. TRPs in most cases will be designed for a $PFC_{MAX}$ which is likely to be less than the most onerous condition. Hence the establishment of some reinforcements can be delayed until after the scenario year. Further, the overall route length of the network lines requiring reinforcement for most the top ten TRPs is 1209.76km (1099.5km OHL, 110.26km UGC). The extent of this proposed onshore reinforcement is achievable in a five-year period; around 848km of route length has recently been reinforced on the GB transmission network in a five-year period since consent was granted on a number of projects at the beginning of 2010 [5.12]. Namely projects involving conductor uprating/installation from Beauly – Denny (220km), Beauly – Blackhillock – Kintore (155km) and Beauly – Dounreay (153km) in Northern Scotland, Harker – Hutton – Quernmore (116km) in Northern England, Walpole – Norwich – Bramford (140km) in South Eastern England and Trawsfynydd – Treuddyn (64km) in Northern Wales.

The GB SO, with input from the Electricity Network Strategies Group (a high-level forum which brings together key stakeholders in electricity networks), evaluated a pre-defined set of transmission reinforcements proposed by the GB TNOs, for a 2008 version of the Gone Green scenario in a study carried out in 2009 [5.1]. An updated account of this evaluation was subsequently carried out against a 2011 version of the Gone Green scenario in a study carried out in 2012 [5.2]. The 2011 version of the Gone Green scenario had been developed from the 2008 version and had been updated considering stakeholder feedback. At the time of utilising the MOTREP framework and carrying out analysis on the Gone Green scenario developed by National Grid, the 2011 version was the most recent publication.

The network reinforcements proposed by the GB TNOs in the 2012 study were developed against both the security and economy planned transfer criterion and so satisfied the NETS SQSS criteria (version 2.2, 2012) [5.13]. Reinforcements were therefore proposed against a background where generating unit outputs and power flows were set to those arising from the

EPTC. On the other hand, the network reinforcements proposed by the GB TNOs in the 2009 study were developed against the security planned transfer criteria according to an earlier version of the NETS SQSS. This condition excluded the economy criterion of the EPTC, but a CBA was performed in the 2009 study and the key background assumptions and objective evaluations of the CBA were included in the report. In the 2012 study however, only specific details on the investment cost requirement of the reinforcements was disclosed in the publication.

The MOTREP framework utilises the EPTC to generate reinforcement plans at winter peak demand, however the objectives considered are similar to the objectives of the CBA in the 2009 study. To compare the nondominated solutions and objective evaluations achieved by the MOTREP framework to solutions provided by the GB TNOs, a comparison is therefore made to the 2009 study; with the caveat that the EPTC is a more onerous criterion for some areas of the GB network. The 2009 study includes a scenario variant (used in a sensitivity analysis) of the 2008 version of the Gone Green scenario which is similar to the 2011 Gone Green scenario generation mix.

In the 2009 study, eight possible network configurations were assessed with a CBA. Much of the network configurations were designed to alleviate areas of expected high network congestion (i.e. mainly between Scotland and England). The reinforcement options ranged from a solution that excluded the addition of new circuits (i.e. involving line reconductoring and series compensation) costing an estimated £625million (£465million excluding the use of FACTS devices), to a solution that included the same network upgrades as well as two offshore DC cables running down either side of the Scotland to England border; costing an estimated £2.077billion overall (£1.917billion excluding series compensation).

The DC cable on the west coast of the UK – connected between Hunterston (generation zone 7) and Deeside (zone 13) – was estimated in the study to be approximately 340km in length and cost £762million (excluding offset costs from asset replacement). This project has now been commissioned and is scheduled to be complete in 2016 [5.14]. The DC cable on the east coast – connected between Peterhead (zone 2) and Hawthorn Pit (zone 10) – was estimated to be approximately 360km in length and cost £690million.

In the 2009 study, for a scenario variant which involved 11.4GW of onshore wind capacity to be situated in Scotland, the constraint cost of the 2014/15 base case network in 2020 was estimated to be £1,013.3million – in comparison to £903.84million calculated in the MOTREP framework for 8.4GW of onshore wind capacity – and savings of between £371.9million (resulting from the connection of the west coast HVDC cable only) and £823.2million (resulting from line upgrades and the connection of both HVDC cables) could be achieved using the proposed network configurations. It is clear from Table 5-8 that the TRP solutions produced by the MOTREP framework can achieve similar levels of annual constraint cost saving for similar levels of investment cost.

For the network configurations outlined above (i.e. line reconductoring only and line upgrades plus offshore HVDC cables), it was estimated in the 2009 study that they will require an outage cost of £117million and £121million respectively for installation and achieve an annual line loss saving of 0.3TWh and 1.1TWh. The nondominated TRP solutions generated by the MOTREP framework require higher levels of outage cost for installation due to the onshore location of the reinforcements. The east and west coast HVDC cables were estimated in the study to require little or no outages respectively (a cost of only £4million was estimated for the east coast HVDC cable due to the outage of substations). However, the resulting annual line loss savings of the nondominated solutions are greater, for the same reason, offsetting the associated outage cost and maintaining roughly the same ratio between outage cost and annual line loss saving as estimated in the 2009 study.

The entire pool of reinforcements proposed by 2020 in the 2009 study, including reinforcements deemed to be required in Wales (North and Central) and England (East and South), had an estimated capital expenditure of £4.73billion and was assessed to be able to accommodate between 26GW and 34GW of wind generation and between 3.3GW and 9.9GW of nuclear generation. The generation mix created for this case study to represent the 2011 Gone Green scenario (see Appendix C.1.) includes only 25.8GW of wind generation and 12.3GW of nuclear generation. The MOTREP framework located a wide range of nondominated solutions for the scenario, requiring a capital expenditure of between £1.28billion and £7.51billion; the average being £4.28billion. Further, when analysing the trade-offs associated with the planning objectives (excluding annual constraint cost saving), network investment below £4.08billion is advised by the framework to achieve a satisfactory cost benefit. By using (5-1), several top performing TRP solutions were located for the multi-objective problem and the best solution (due mainly to the saving in annual constraint costs) was estimated to require a capital expenditure of £1.50billion. Hence, according to the modelling approach proposed, it can be concluded that a minimum investment cost of £1.50billion is required for the onshore GB transmission network to accommodate the 2011 Gone Green scenario in 2020. However, a cost of up to £4.08billion is more likely to be required to efficiently accommodate generation for the scenario year and beyond.

Due to the similarity in the objective evaluations of the reinforcement solutions created by the TNOs and the MOTREP framework, this analysis demonstrates the applicability and value of the MOTREP framework to evaluate the thermal and economic impact of a future energy scenario to the GB electrical transmission network.

## 5.4. *Year 2035 Case Studies: Market Rules and Central Co-ordination Scenarios*

The Market Rules and Central Co-ordination scenarios were created by phase one of the *Transition Pathways to a Low Carbon Economy* project [5.15]. These scenarios analyse the alternative potential transitions to a UK low-carbon economy over the period from 2011 to 2050. Market Rules is a business as usual scenario which envisions the broad continuation of the current governance pattern, involving minimal interference to market arrangements in energy services [5.15]. Central Co-ordination on the other hand envisions greater governmental involvement in the governance of energy systems and entails the introduction of non-behavioural demand side measures, increasing energy efficiency standards on products and new-build housing [5.15].

Quantitative information for significant years of each scenario was created in the project to envision the evolution of the UK system generation mix. The 2035 generation mix of each scenario was chosen as a case study in this thesis due to the significant differences which exist between each generation mix. Further, the year 2035 was seen by the project as a crucial year in both scenarios for the evolution of the UK system towards achieving government environmental targets in 2050. Hence both case studies provide a good example of the value of the MOTREP framework for scenario evaluation.

Table 5-10 details the generation mix for the UK system of both scenarios in the year 2035, as well as the transmission connected generation mix of each scenario as a result of the sizes, selections and locations of generating units and interconnectors made using the method detailed in section 4.2. of Chapter 4. The supply selections made and underlying assumptions regarding the prediction of transmission connection for each plant type, to model the Market Rules and Central Co-ordination scenarios, are detailed in Appendix C.2. and Appendix C.3. respectively. The ACS peak demand of Market Rules is estimated to be 10.67GW higher in 2035 than the peak demand of Central Co-ordination. There are therefore significant differences in both generation capacity and penetration (in particular as a function of total supply) in the resulting scenario-related transmission connected generation mixes. These differences are:

- An increase of 8.85GW in coal generation with CCS for Market Rules, with a penetration equivalent to 11.49% of total supply (compared to 5.43% for Central Co-ordination);
- An increase of 6.91GW in gas generation for Market Rules;
- An increase of 5.62GW in generation from offshore wind for Market Rules, with a penetration equivalent to 13.16% (compared to 10.29% for Central Co-ordination); and
- An increase of 5.03GW in nuclear generation for Central Co-ordination, with a penetration equivalent to 20.02% (compared to 13.30% in Market Rules);

**Table 5-10 Market Rules and Central Co-ordination Scenario Generation Mixes for the year 2035**

| Generator Type | Market Rules (GW) | | Central Co-ordination (GW) | |
|---|---|---|---|---|
| | System | Transmission | System | Transmission |
| Coal CCS | 14.90 | 14.89 | 6.00 | 6.04 |
| Gas | 22.90 | 21.49 | 16.00 | 14.58 |
| Gas CCS | 16.00 | 16.22 | 17.00 | 17.36 |
| Nuclear | 17.22 | 17.23 | 22.08 | 22.26 |
| CHP | 9.58 | 5.24 | 9.39 | 5.04 |
| Onshore Wind | 16.40 | 12.63 | 15.37 | 11.96 |
| Offshore Wind | 18.68 | 17.06 | 12.61 | 11.44 |
| Hydro | 1.70 | 1.12 | 1.70 | 1.12 |
| Biomass | 1.52 | 1.10 | 1.52 | 1.10 |
| Marine | 13.73 | 13.70 | 11.00 | 11.03 |
| Pumped Storage | 2.78 | 2.74 | 2.78 | 2.74 |
| Imports | 6.11 | 6.17 | 6.81 | 6.54 |
| **Total Supply** | **141.70** | **129.59** | **124.32** | **111.21** |
| **ACS Peak Demand (including losses, excluding plant demand and exports)** | **79.57** | | **68.90** | |

Figure 5-3 and Figure 5-4 detail the estimated distribution of transmission connected generation capacity for each scenario and each generator type across the three TNO regions of the GB network. Again, NGET's area has been split into a north and south region for illustration. An offshore wind capacity of 14.7GW is estimated to be located in NGET's area (both north and south) for Market Rules in comparison to 9.6GW for Central Co-ordination. Similarly to the Gone Green scenario in 2020, the majority of transmission connected onshore wind generation in the UK is predicted to be located in Scotland, with a respective total TEC of 9GW and 8.3GW for Market Rules and Central Co-ordination (in comparison to 8.4GW for Gone Green). For Central Co-ordination, a greater capacity of nuclear generation in comparison to Market Rules is predicted to be connected in the south of England (an additional 4GW) and southern Scotland (an additional 1.1GW). Further, no coal generation (with CCS) is predicted to be located in the south of England (compared to 4.6GW for Market Rules) and less offshore wind capacity is predicted to be located in NGET's area; a reduction of 5.1GW.

Similarly to the Gone Green 2011 scenario, transmission connected supply significantly exceeds the assumed ACS peak demand for the scenario; by 50GW for Market Rules and by

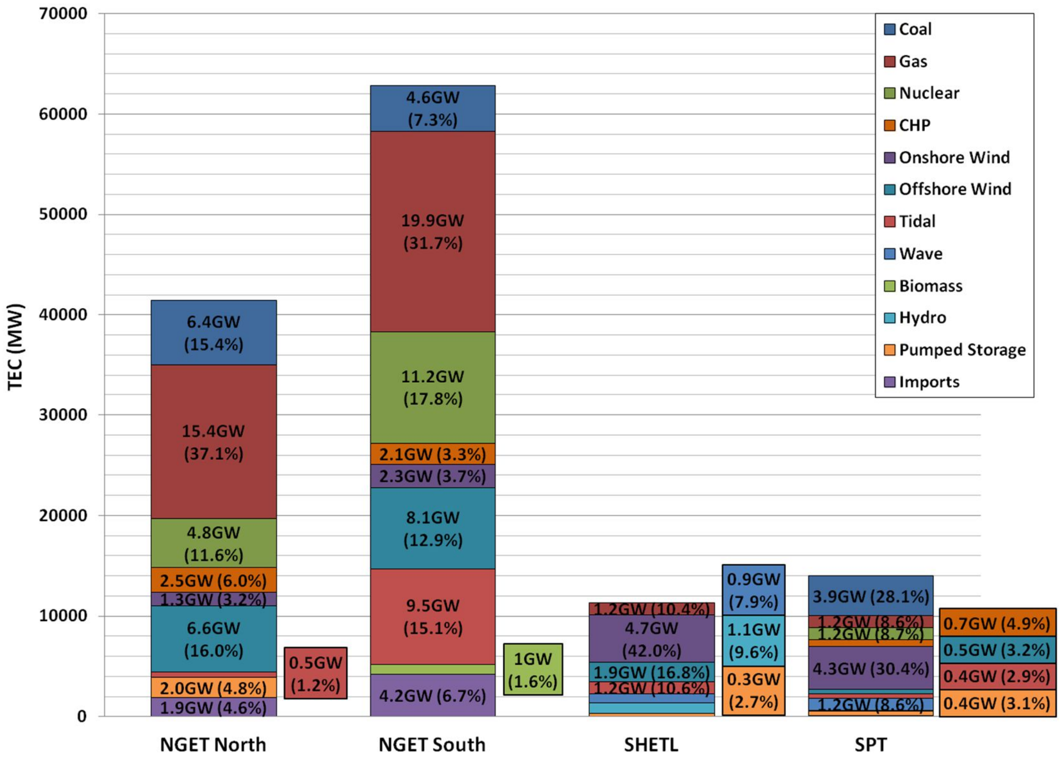


**Figure 5-3 Distribution of transmission connected generation TEC across the GB network for the Market Rules scenario in the year 2035**

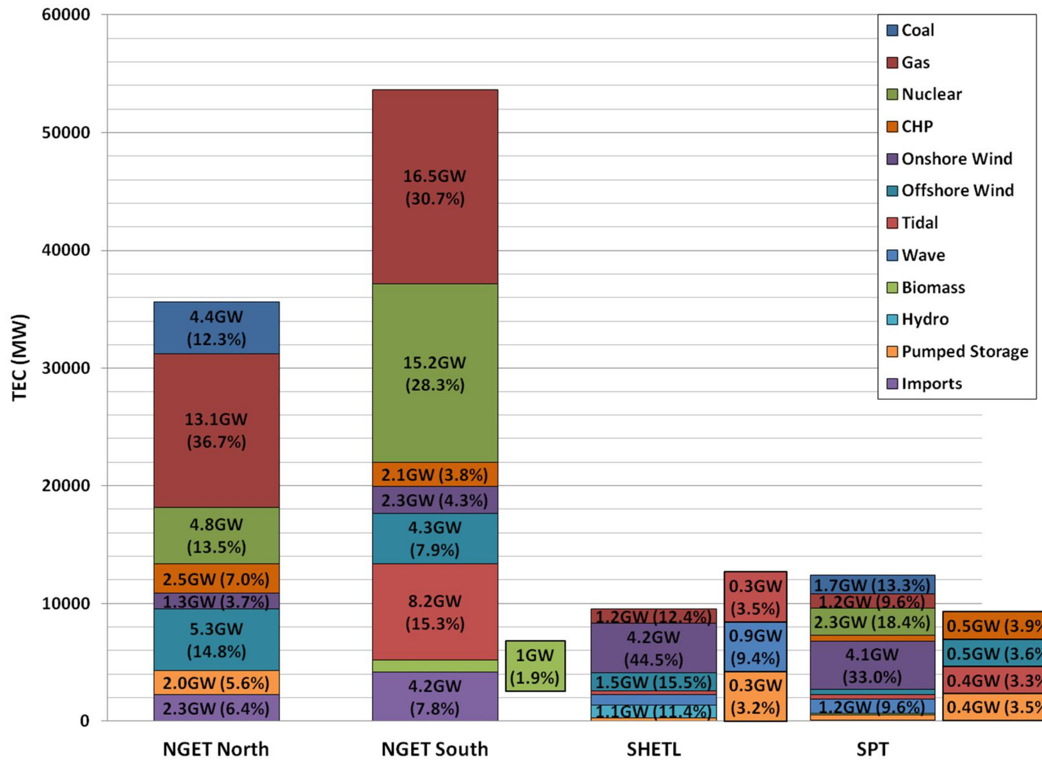


**Figure 5-4 Distribution of transmission connected generation TEC across the GB network for the Central Co-ordination scenario in the year 2035**

42.3GW for Central Co-ordination (in comparison to 42.8GW for Gone Green). Hence again a de-rated capacity margin of 5% for TEC from wind is used to calculate the plant margin. Also, similarly to the setup of the MOTREP framework for Gone Green, a 100% margin is used for marine TEC in the calculation of plant margin, and in the calculation of the outage cost of a TRP. Summer season availability parameters of 27.9% and 37.5% for onshore and offshore wind generating units are again used in the application of the adapted planned transfer condition. Further, the availability parameter for TEC from both wave and tidal is again assumed to be 100%, leaving the output of these units to be scaled down in the framework using the scaling factor.

The generator type ranking order (required in the application of the EPTC) used for the case studies involving Market Rules and Central Co-ordination differs from the ranking order used for Gone Green. Table 5-11 details the ranking order utilised for both case studies in the year 2035. The ranking order utilised for the 2020 case study and the case studies for 2035 was obtained from the NETS SYS. A ranking order of generating units across the GB transmission network for the next seven years (beyond the year of the statements publication) was tabulated in each SYS. The ranking orders used in this thesis were obtained by analysing the types of generators and their rank from the SYS.

To compare the reinforcement solutions of the MOTREP framework to solutions created by the GB TNOs in the 2009 study, the generator type ranking order used was obtained from the 2009 NETS SYS [5.9]; where generating units were ranked according to their expected operation at ACS peak demand from 2009/10 to 2015/16. Here it was found that generation from CHP schemes and CCGT generating units was ranked high, and generation from renewable sources (except for onshore wind) was ranked low; only exceeding coal generation and marginal plant. For the 2035 case studies, the generator type ranking order was obtained from the 2011 NETS SYS [5.16]. This time generating units were ranked according to their expected operation at ACS peak demand from 2011/12 to 2017/18. The resulting generator type ranking order, as shown in Table 5-11, gives generation from renewable sources (except for biomass) a high ranking and CHP a lower rank. It is clear that generating unit operation over winter periods – a basis for determining the ranking order – had altered. Further, as a result (mainly) of a continued increase in the supplier's obligation for renewable generation (i.e. ROCs/MWh) at the time, and a continued increase in the buy-out price which suppliers must pay Ofgem for each ROC not presented towards compliance with their obligation [5.17], an increased contribution of renewable generation at peak demand had been predicted.

**Table 5-11 Generator Type Ranking Order for Market Rules and Central Co-ordination (source [5.16])**

| Generator Type | Rank |
|---|---|
| Offshore Wind | 1 |
| Tidal | 2 |
| Wave | 3 |
| Onshore Wind | 4 |
| Nuclear | 5 |
| Hydro | 6 |
| Base CCGT with CCS | 7 |
| Biomass | 8 |
| Base Coal with CCS | 9 |
| CHP | 10 |
| Base CCGT | 11 |
| Base Coal | 12 |
| Marginal CCGT | 13 |
| Marginal Coal | 14 |
| Pumped Storage | 15 |
| OCGT | 16 |

The generator type ranking order detailed in Table 5-11 is used for both the winter and summer seasons of the scenario year (to calculate the annual constraint cost saving of a reinforcement plan) and as the summer ranking order for the 2035 case studies (to represent the summer seasons in the calculation of outage cost). To calculate the outage cost of a reinforcement plan, the median summer minimum demand value used for Market Rules and Central Co-ordination is 26.26GW and 24.52GW respectively; calculated as the midpoint between the minimum demand value of the base case network (22711MW) and the minimum demand value of the scenario (29.81GW and 26.32GW respectively). The minimum demand value in this case had been calculated by the Future Energy Scenario Assessment (FESA) tool employed in phase one of the 'Transition Pathways' project [5.15]. Further, the number of outage groups used for both scenarios to satisfy the general rule is 40. Hence the GB network would need to accommodate two outage groups per year from 2015 until 2034.

Following the identification of contributory generating units at scenario peak demand, the application of the EPTC, and the use of a DCPF within the framework, 50 thermal limit violations above the most onerous power flow condition (an 84% $PFC_{MAX}$) were discovered in the base case network for Central Co-ordination and 88 thermal limit violations were discovered for Market Rules, as detailed in Table 5-12. Hence Market Rules is likely to present a greater transmission planning problem than Central Co-ordination. Compared to the Gone Green scenario, a greater number of thermal violations occur for both scenarios across strategic lines of a high voltage and a long route length.

**Table 5-12 Thermal limit violations above an 84% $PFC_{MAX}$ resulting from the EPTC for the Market Rules (MR) and Central Co-ordination (CC) Scenario**

| Zone | fbus | tbus | No. of Lines | OHL (km) | UGC (km) | Voltage (kV) | Capacity (MVA) | MR Violation (%) | CC Violation (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 21 | 780 | 1 | 55.8 | 0.0 | 275 | 535 | 150.6 | 103.8 |
| 1 | 21 | 41 | 1 | 35.4 | 0.0 | 275 | 535 | 150.6 | 103.8 |
| 1 | 40 | 605 | 1 | 30.9 | 0.0 | 132 | 132 | 183.7 | 155.0 |
| 1 | 40 | 604 | 1 | 30.9 | 0.0 | 132 | 126 | 209.4 | 179.3 |
| 1 | 40 | 439 | 1 | 15.4 | 0.0 | 132 | 126 | 106.9 | 96.1 |
| 1 | 40 | 440 | 1 | 15.4 | 0.0 | 132 | 126 | 106.9 | 96.1 |
| 1 | 41 | 786 | 1 | 130.2 | 0.0 | 275 | 665 | 161.5 | 109.0 |
| 1 | 61 | 499 | 1 | 51.5 | 0.0 | 275 | 525 | 129.2 | 96.7 |
| 1 | 150 | 499 | 1 | 34.4 | 0.0 | 275 | 880 | 89.9 | n/a |
| 1 | 221 | 786 | 1 | 23.2 | 0.0 | 275 | 665 | 128.8 | 85.2 |
| 1 | 221 | 364 | 1 | 57.9 | 0.0 | 275 | 535 | 132.6 | 85.9 |
| 1 | 364 | 780 | 1 | 11.3 | 0.0 | 275 | 535 | 141.8 | 95.0 |
| 1 | 471 | 353 | 1 | 41.3 | 0.0 | 132 | 126 | 118.1 | 113.2 |
| 1 | 499 | 803 | 2 | 100.6 | 0.0 | 275 | 695 | 90.7 | n/a |
| 1 | 514 | 730 | 1 | 10.5 | 0.0 | 132 | 111 | 122.7 | 120.3 |

**Table 5-12 Thermal limit violations above an 84% $PFC_{MAX}$ resulting from the EPTC for the Market Rules (MR) and Central Co-ordination (CC) Scenario**

| Zone | fbus | tbus | No. of Lines | OHL (km) | UGC (km) | Voltage (kV) | Capacity (MVA) | MR Violation (%) | CC Violation (%) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 578 | 494 | 1 | 145.4 | 0.0 | 275 | 885 | 89.1 | n/a |
| 1 | 604 | 730 | 1 | 31.2 | 0.0 | 132 | 132 | 150.8 | 122.7 |
| 1 | 605 | 730 | 1 | 31.2 | 0.0 | 132 | 126 | 173.8 | 144.3 |
| 3 | 23 | 234 | 1 | 14.0 | 0.0 | 132 | 83 | 113.4 | 117.2 |
| 3 | 102 | 262 | 1 | 44.9 | 0.0 | 132 | 83 | 174.3 | 177.8 |
| 3 | 102 | 688 | 1 | 63.4 | 0.0 | 132 | 83 | 160.9 | 166.2 |
| 3 | 234 | 262 | 1 | 9.0 | 0.0 | 132 | 83 | 139.4 | 142.9 |
| 3 | 303 | 548 | 1 | 8.5 | 0.0 | 132 | 126 | 98.1 | 103.2 |
| 3 | 548 | 688 | 1 | 18.3 | 0.0 | 132 | 111 | 128.1 | 131.7 |
| 4 | 289 | 482 | 1 | 36.9 | 0.0 | 132 | 132 | 130.0 | n/a |
| 4 | 482 | 445 | 2 | 33.7 | 0.0 | 132 | 132 | 88.4 | n/a |
| 4 | 668 | 881 | 1 | 0.0 | 3.7 | 132 | 120 | 86.9 | n/a |
| 5 | 185 | 187 | 1 | 0.0 | 1.0 | 132 | 194 | 94.6 | n/a |
| 5 | 186 | 188 | 1 | 0.0 | 1.0 | 132 | 194 | 94.6 | n/a |
| 5 | 187 | 423 | 1 | 0.0 | 41.0 | 132 | 194 | 94.6 | n/a |
| 5 | 188 | 424 | 1 | 0.0 | 41.0 | 132 | 194 | 94.6 | n/a |
| 6 | 199 | 496 | 1 | 55.3 | 0.0 | 275 | 1090 | 85.7 | n/a |
| 6 | 263 | 609 | 1 | 15.4 | 0.0 | 275 | 955 | 104.6 | n/a |
| 6 | 373 | 496 | 1 | 14.4 | 0.0 | 275 | 1050 | 92.9 | n/a |
| 6 | 494 | 496 | 1 | 9.7 | 0.4 | 275 | 760 | 103.7 | n/a |
| 6 | 517 | 209 | 1 | 32.2 | 0.0 | 275 | 885 | 110.4 | n/a |
| 7 | 156 | 544 | 1 | 54.8 | 0.0 | 275 | 1120 | 86.1 | n/a |
| 7 | 160 | 282 | 1 | 26.7 | 0.0 | 400 | 2130 | 92.8 | n/a |
| 7 | 160 | 773 | 1 | 21.7 | 0.0 | 400 | 2130 | 91.1 | n/a |
| 7 | 161 | 772 | 1 | 21.7 | 0.0 | 400 | 2130 | 91.1 | n/a |
| 7 | 236 | 447 | 1 | 7.9 | 3.4 | 132 | 110 | 96.0 | 92.4 |
| 7 | 237 | 448 | 1 | 7.9 | 3.4 | 132 | 110 | 96.0 | 92.4 |
| 7 | 257 | 824 | 2 | 34.3 | 2.2 | 400 | 1250 | 107.3 | 98.0 |
| 7 | 270 | 866 | 1 | 0.0 | 6.0 | 275 | 457 | 93.1 | 93.1 |
| 7 | 282 | 160 | 1 | 27.4 | 0.0 | 400 | 2010 | 98.3 | 86.4 |
| 7 | 282 | 592 | 1 | 23.4 | 0.0 | 400 | 1910 | 141.1 | 125.9 |
| 7 | 357 | 116 | 1 | 2.9 | 0.0 | 132 | 123 | 99.3 | n/a |
| 7 | 358 | 117 | 1 | 2.9 | 0.0 | 132 | 123 | 99.3 | n/a |
| 7 | 375 | 376 | 1 | 41.7 | 0.0 | 400 | 1910 | 141.1 | 125.9 |
| 7 | 422 | 423 | 1 | 0.0 | 3.5 | 132 | 194 | 94.6 | n/a |
| 7 | 422 | 424 | 1 | 0.0 | 3.5 | 132 | 194 | 94.6 | n/a |
| 7 | 447 | 823 | 1 | 0.0 | 1.1 | 132 | 110 | 96.0 | 92.4 |
| 7 | 448 | 823 | 1 | 0.0 | 1.1 | 132 | 110 | 96.0 | 92.4 |
| 7 | 609 | 889 | 2 | 15.8 | 0.0 | 275 | 285 | 138.1 | 98.2 |
| 7 | 624 | 116 | 1 | 19.2 | 0.0 | 132 | 123 | 99.3 | n/a |
| 7 | 624 | 117 | 1 | 19.2 | 0.0 | 132 | 123 | 99.3 | n/a |
| 7 | 824 | 191 | 1 | 9.4 | 2.0 | 400 | 1000 | 96.5 | n/a |
| 9 | 137 | 374 | 2 | 13.0 | 0.0 | 132 | 132 | 105.7 | 98.9 |
| 9 | 137 | 389 | 1 | 15.1 | 0.0 | 132 | 132 | 97.8 | 90.5 |
| 9 | 235 | 822 | 1 | 43.6 | 0.0 | 132 | 132 | 125.9 | 100.2 |
| 9 | 356 | 821 | 1 | 33.2 | 0.0 | 132 | 132 | 111.7 | 86.8 |
| 9 | 356 | 624 | 2 | 30.0 | 0.0 | 132 | 125 | 91.9 | n/a |
| 9 | 389 | 401 | 1 | 9.9 | 0.0 | 132 | 131 | 98.6 | 91.2 |
| 9 | 391 | 591 | 1 | 44.1 | 0.0 | 400 | 2010 | 93.0 | n/a |
| 9 | 391 | 403 | 1 | 10.2 | 0.0 | 400 | 2010 | 93.0 | n/a |
| 9 | 392 | 403 | 1 | 10.2 | 0.0 | 400 | 2010 | 146.5 | 131.7 |
| 9 | 392 | 375 | 1 | 9.9 | 0.0 | 400 | 2010 | 146.5 | 131.7 |
| 9 | 403 | 430 | 2 | 81.9 | 0.0 | 400 | 1390 | 164.1 | 138.9 |
| 9 | 430 | 685 | 1 | 34.5 | 0.0 | 400 | 2010 | 110.6 | 94.0 |

**Table 5-12 Thermal limit violations above an 84% $PFC_{MAX}$ resulting from the EPTC for the Market Rules (MR) and Central Co-ordination (CC) Scenario**

| Zone | fbus | tbus | No. of Lines | OHL (km) | UGC (km) | Voltage (kV) | Capacity (MVA) | MR Violation (%) | CC Violation (%) |
|---|---|---|---|---|---|---|---|---|---|
| 9 | 430 | 686 | 1 | 34.5 | 0.0 | 400 | 1390 | 155.6 | 132.2 |
| 9 | 470 | 674 | 1 | 43.5 | 0.0 | 400 | 2210 | 106.3 | 94.5 |
| 9 | 476 | 478 | 1 | 2.0 | 0.0 | 132 | 123 | 108.6 | 85.8 |
| 9 | 647 | 675 | 1 | 37.6 | 0.0 | 400 | 2090 | 90.5 | n/a |
| 10 | 640 | 851 | 1 | 8.3 | 0.0 | 275 | 1090 | 98.3 | 90.2 |
| 10 | 65 | 835 | 1 | 16.8 | 0.0 | 275 | 1240 | 86.3 | n/a |
| 10 | 410 | 640 | 1 | 9.5 | 0.0 | 275 | 1090 | 89.5 | n/a |
| 10 | 512 | 810 | 1 | 7.4 | 0.3 | 400 | 1590 | 103.3 | n/a |
| 10 | 759 | 851 | 1 | 4.4 | 0.0 | 275 | 1030 | 87.9 | n/a |
| 10 | 760 | 851 | 1 | 4.4 | 0.0 | 275 | 1030 | 84.2 | n/a |
| 13 | 130 | 470 | 1 | 13.4 | 0.0 | 400 | 2210 | 106.3 | 94.5 |
| 13 | 418 | 852 | 1 | 14.9 | 0.2 | 400 | 1890 | 85.3 | n/a |
| 14 | 39 | 860 | 2 | 9.7 | 0.1 | 400 | 2010 | 84.1 | 89.9 |
| 14 | 526 | 737 | 1 | 0.0 | 1.5 | 132 | 500 | 140.0 | 140.0 |
| 15 | 693 | 840 | 1 | 72.6 | 2.5 | 400 | 1100 | 97.6 | n/a |
| 15 | 703 | 840 | 1 | 99.6 | 2.5 | 400 | 1100 | 111.5 | 95.9 |
| 16 | 147 | 861 | 1 | 0.0 | 9.5 | 400 | 1412 | n/a | 86.5 |
| 16 | 148 | 862 | 1 | 0.0 | 9.4 | 400 | 1412 | n/a | 86.7 |
| 18 | 76 | 306 | 1 | 7.8 | 3.6 | 400 | 1110 | 105.5 | n/a |
| 18 | 101 | 575 | 2 | 81.8 | 0.0 | 400 | 1390 | 87.2 | n/a |
| 19 | 306 | 551 | 1 | 22.6 | 3.9 | 400 | 1110 | 90.8 | n/a |

As a result of Market Rules in 2035, thermal limit violations are predicted to occur in generation zones 4 (east central Scotland), 5 (west side of Scotland's central belt), 6 (east side of Scotland's central belt), 18 and 19 (south midpoint of England), where violations do not exist from the application of Central Co-ordination. This is probably due to the predicted increased total TEC in SHE-T and SPT's area for Market Rules compared to Central Co-ordination (513MW and 156MW added onshore wind generation in SHE-T's and SPT's area respectively; 420MW and 868MW added offshore wind and tidal generation in SHE-T's area and 2284MW added coal generation in SPT's area via Longannet power station, retrofitted with CCS). Also, the thermal violations in zones 18 and 19 for Market Rules are a result of a predicted increase in 9.21GW of generation connections in the south of NGET's area compared to Central Co-ordination. Further, excluding the violations discovered in zone 3, in general the severity of the thermal loading above zone 6 (from the south of Scotland down to the south of England) is greater for Market Rules than Central Co-ordination across the same circuits.

Similarly to the Gone Green scenario, the locations of many of the thermal violations for both scenarios relate to key circuits in the flow of power from north to south. Both scenarios again result in several violations across circuits in zone 9; particularly down the west corridor on the

Harker-Hutton-Penwortham line. However, whereas the Gone Green scenario caused a severity of thermal loading up to 111.3% in zone 9 across the Harker-Hutton double circuit line (see Table 5-3); Market Rules and Central Co-ordination result in a greater thermal loading of up to 164.1% and 138.9% respectively across the same line.

Several thermal violations are observed for Market Rules in zone 10 across key circuits for the east corridor; particularly the 400kV Lackenby-Thornton double-circuit line. However for Central Co-ordination, only one violation is observed in zone 10 across a less strategic line (of only 8.3km in length at a voltage level of 275kV). Both scenarios present a different transmission planning problem for the year 2035, and considering the extent of the thermal issues discovered in the 2014/15 base case network, significant network reinforcement is required.

The parameters used for both 2035 case studies in the SPEA2 optimisation are shown in Table 5-13. For these case studies, each TRP evaluation took an average of 17.65 seconds[12] (for 100 DCOPF calculations in the evaluation of $CC_{SAV}$ and the use of 40 outage groups in the evaluation of $OC_{TRP}$) and the total evaluation time for 400 generations was 392 hours.

### 5.4.1. Case Study 2: Results and Discussion for Market Rules

The framework nondominated multi-objective results for the Market Rules scenario are shown in the bi-objective plot in Figure 5-5. It was found that one nondominated TRP solution generated by the SPEA2 failed the security test (as detailed in section 4.9.). This solution (included and highlighted as a red dot in Figure 5-5) has therefore been excluded in the analysis of the results.

**Table 5-13 2035 Case Study Parameters for SPEA2 Optimisation**

| | |
|---|---|
| **Population size** | 200 |
| **Archive size** | 120 |
| **Generations** | 400 |
| **Crossover type** | Uniform |
| **Crossover probability** | 0.9 |
| **Mutation type** | Constant Rate |
| **Mutation probability** | 0.001 |
| **Mutation route** | 2 |

[12] Evaluation time is based on the same computing power as with the Gone Green case study.

It is clear from the results that (as expected) Market Rules in 2035 requires a greater level of network investment than Gone Green in 2020. To meet an electrical demand of 59GW using the proposed generation mix for Gone Green (Table 5-1) was estimated to require a network CAPEX of between £1.28billion and £7.51billion, whereas to meet an electrical demand of 79.57GW, using the proposed generation mix for Market Rules, the MOTREP framework estimates a required CAPEX of between £3.58billion and £15.70billion. By increasing network investment in this case (from £3.58billion to £15.70billion), annual line losses can be reduced by 5.46TWh (see Figure 5-5(a)), compared to 3.62TWh for Gone Green – equating to an annual saving of £217.2million (using £60/MWh as a conservative cost of future energy) – whereas the annual incremental O&M cost of a TRP is found to increase from £1.78million to £11.42million (see Figure 5-5(b) and Figure 5-5(c)) and outage costs (generally) are found to increase from £136.79million to £1.97billion (see Figure 5-5(d)), compared to an increase from £198.47million to £1.66billion for Gone Green.

An estimation of the Pareto front has been included in Figure 5-5(a), Figure 5-5(c) and Figure 5-5(d). In this case, from an investment cost of £3.58billion to £4.24billion, annual line losses can be reduced by 1.03TWh at a rate of 1.56GWh per £1million. However, between £4.24billion and £13.06billion and between £13.06billion and £15.70billion, annual line losses can only be reduced by 5.02TWh and 0.42TWh at a lower rate of 0.57GWh and 0.16GWh per £1million respectively – in this case line loss saving approaches saturation at around 12TWh; around double the saturation point for Gone Green in 2020. For the case of network outages, from an investment cost of £3.92billion to £12.26billion, outage costs increase by £234.85million at a rate of only £28.16k per £1million of network investment. However, from £12.26billion to £15.50billion outage costs increase by £773.46million at a greater rate of £238.72k per £1million of network investment; again, a result of an increased usage of SCAs and DCAs in reinforcement solutions which consequently require a greater level of network investment.

Overall with each additional £1million expenditure on the GB onshore transmission network, from an initial outlay of £3.58 billion, a further upfront cost of £152k for network outages could be required and an increased annual cost saving of only £17k (reduced slightly to consider the minimal increase in incremental O&M cost) from reducing line losses could be achieved. In this case, it is estimated to take nearly 9 years, as opposed to 7 years for Gone Green, for the estimated savings from further network expansion to recuperate the upfront

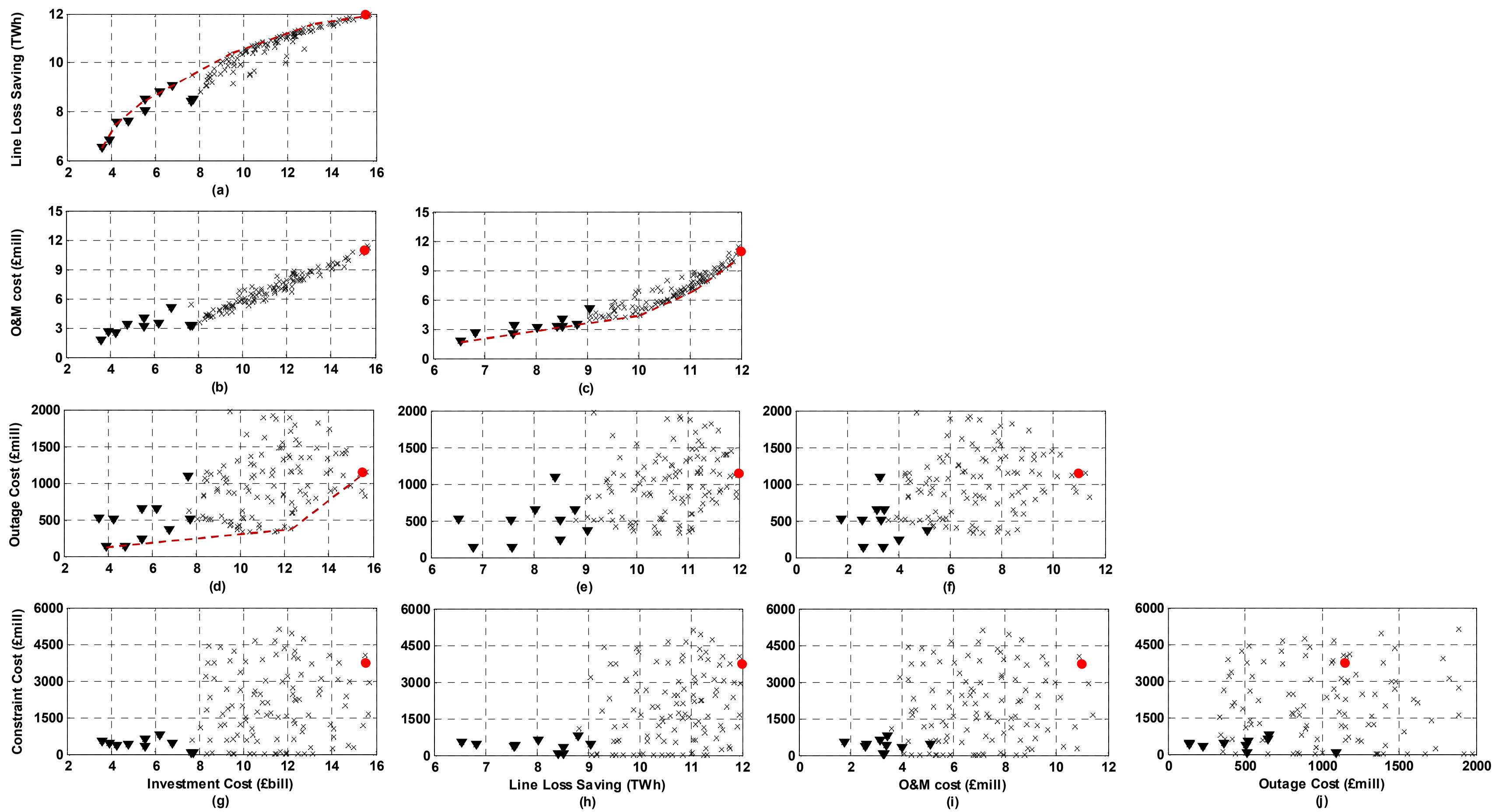


**Figure 5-5 MOTREP framework nondominated multi-objective results for the Market Rules scenario in 2035**

outage cost. However, for an investment cost of up to £4.24billion, each additional £1million expenditure could require a more reasonable increased upfront cost of £28.16k for network outages and achieve an improved further annual cost saving of £92k (reduced slightly according to the minimal increase in incremental O&M cost). For an investment cost of up to £12.26billion, each additional £1million expenditure could achieve an increased annual cost saving of £33k for the same upfront cost (£28.16k). Hence, excluding the economic savings from alleviating annual congestion, network investment above £3.58billion – up to £4.24billion or a maximum of £12.26billion – is advised for Market Rules to further compensate for upfront outage costs.

In assessing network constraints, the DCOPF could not always converge for Market Rules or Central Co-ordination when calculating the quantity of constrained off generation across the year as a result of the unreinforced base case network. The quantity of thermal violations for both scenarios (see Table 5-12) is significantly higher than for Gone Green (see Table 5-3). Hence generating units which needed to be constrained on to accommodate for the loss of generation, as a result of thermal constraints, were therefore also restricted by the base case network and the total generation able to be accommodated by the network was less than the electrical demand for the simulation.

To counteract this issue – as the fitness function of the SPEA2 in the MOTREP framework has been designed to calculate the fitness of each TRP based partly on the requirement of maximising annual constraint cost saving ($CC_{SAV}$) – $CC_{ORIG}$ is allocated a value of zero within the framework in the event of a failed DCOPF calculation during the annual assessment, and the maximisation of $CC_{SAV}$ in (4-11a) within the SPEA2 effectively results in a minimisation of $CC_{NEW}$ and a negative value of $CC_{SAV}$ for each reinforcement plan generated. The chosen route for mutation in the SPEA2 therefore needs to be route two and following the application of the MOTREP framework, nondominated TRPs are then located for the multi-objective problem involving annual constraint costs as opposed to a saving in annual constraint costs. The nondominated TRP solutions shown in Figure 5-5, result in an annual constraint cost for Market Rules from as little as £1.61million to as high as £5.12billion. The reinforcement solutions generated by the MOTREP framework, due to the use of an 84% $PFC_{MAX}$ as the most onerous condition and the application of the EPTC, did not result in a failed DCOPF calculation in the assessment of $CC_{NEW}$ for Market Rules or Central Co-ordination.

Similarly to Gone Green, the resulting peak constraint cost of each reinforcement plan during the winter season is less than the summer season and summer outage season; an expected consequence as a result of each reinforcement plan being designed to cater for generating unit outputs at winter peak demand. Thermal constraints therefore often result at lower electrical demand under varying seasonal generating unit outputs. This highlights the importance of assessing network constraints across the year and improving the evaluation of a networks constraint cost and constraint cost saving. For the reinforcement plans generated for Market Rules, the peak constraint cost was often located in the summer season and was significantly greater than the peak constraint cost in the winter season; from around 3 to 15 times greater.

**Table 5-14 Common Seasonal Constraint Actions for Market Rules arising from Reinforcement Plans in the Nondominated Set**

| Generator Type | Power Station | Network Node(s) (Name/ID) | Constrained Off/On? |
|---|---|---|---|
| **Winter** | | | |
| Nuclear | Oldbury-on-Severn | OLDS10 / 643 | Off |
| CCGT (BL) | Shoreham | BOLN40 / 70 | On |
| CCGT (BL) | Grain | GRAI40 / 367 | On |
| CCGT (BL) | Damhead Creek | KINO40 / 497 | On |
| CCGT (BL) | Marchwood | MAWO40 / 568 | On |
| CCGT (+CCS) | Tilbury C | TILB40 / 817 | On |
| **Summer** | | | |
| Coal (+CCS) | Cottam | COTT40 / 168 | Off |
| Coal (+CCS) | Hunterston | HUER40 / 425 | Off |
| Nuclear | Oldbury-on-Severn | OLDS10 / 643 | Off |
| CHP | Immingham | HUMR40 / 426 | Off |
| CHP | Teesside | GRST20 / 377 | Off |
| CCGT (BL) | Staythorpe | STAY40 / 764 | Off |
| CCGT (BL) | Enfield | BRIM2C_LPN / 96 ; BRIM2D / 97 ; BRIM2A_LPN / 92 ; BRIM2B_LPN / 94 | On (from zero) |
| CCGT (BL) | Marchwood | MAWO40 / 568 | On (from zero) |
| CCGT (BL) | Coryton | COSO40 / 167 | On |
| CCGT (BL) | Grain | GRAI40 / 367 | On |
| CCGT (BL) | Damhead Creek | KINO40 / 497 | On |
| CCGT (+CCS) | Damhead Creek | KINO40 / 497 | On |
| CCGT (+CCS) | Thames Haven | COSO40 / 167 | On |
| CCGT (+CCS) | Tilbury C | TILB40 / 817 | On |
| OCGT | Barking | BARK20_LPN / 38 | On |
| **Summer Outage** | | | |
| Nuclear | Torness | TORN40 / 824 | Off |
| Offshore Wind | Firth of Forth | TORN40 / 824 ; PEHE20 / 657 ; BLYT4A / 66 | Off |
| Marine (Tidal / Wave) | North of Scotland | DOUN20 / 221 | Off |
| CCGT (+CCS) | Brine Field | THOR40 / 810 | On (from zero) |
| CCGT (+CCS) | Barking C | BARK40 / 39 | On (from zero) |

Table 5-14 details the common seasonal constraint actions observed for Market Rules, as a result of the reinforcement plans in the nondominated set. In comparison to the constraint actions common for Gone Green, generation is again constrained off during the year at Cottam, Staythorpe and Immingham. Hence it is clear that the GB transmission network may need reinforced at these locations (subject to a detailed CBA) to ensure that local generation is unrestricted.

As can be seen in Figure 5-5(g)-(j), the trade-offs involving constraint costs are again unclear. However, the top performing TRPs within the nondominated set can again be located using (5-1), and a 'false' assessment of $CC_{SAV}$ which uses a value for $CC_{ORIG}$ which is greater than the maximum value for $CC_{NEW}$ (in this case £6billion). In this instance the top performing TRPs are determined by a rank of the 'false' payback period. The objective evaluations and configurations of the top ten ranked nondominated TRPs with the lowest 'false' payback period are detailed in Table 5-15 and Table 5-16 respectively. Further, the top ten solutions have been highlighted (using a black triangle) in Figure 5-5.

It is clear from Table 5-16 that again line upgrades (UPG) are the significant component and largest single component in the top performing TRPs, compared to single-circuit additions (SCA) and double-circuit additions (DCA). The most significant reinforcements (similar to the case study for Gone Green) are again required in generation zone 9 (north west of England). The specific locations of the thermal violations that result in zone 9 for Market Rules (in 2035) are similar to Gone Green (in 2020), and in seven of the top ten ranking TRP solutions for Market Rules, the location of the most significant reinforcement (in terms of MVA capacity)

**Table 5-15 Top Ten TRP Objective Evaluations for Market Rules according to rank of 'false' Payback Period**

| TRP Rank | $IC_{TRP}$ (£billion) | $CC_{NEW}$ (£million) | $OC_{TRP}$ (£million) | $OM_{TRP}$ (£million) | $LL_{SAV}^{YEAR}$ (TWh) |
|---|---|---|---|---|---|
| 1 | 3.92 | 433.91 | 136.79 | 2.60 | 6.82 |
| 2 | 3.58 | 526.60 | 519.39 | 1.78 | 6.53 |
| 3 | 4.24 | 361.38 | 509.46 | 2.57 | 7.57 |
| 4 | 4.77 | 390.28 | 142.23 | 3.38 | 7.59 |
| 5 | 5.51 | 311.08 | 229.88 | 4.01 | 8.51 |
| 6 | 5.55 | 608.81 | 652.71 | 3.16 | 8.04 |
| 7 | 6.75 | 429.41 | 366.10 | 5.09 | 9.05 |
| 8 | 6.18 | 778.51 | 653.49 | 3.45 | 8.80 |
| 9 | 7.71 | 55.99 | 513.68 | 3.31 | 8.52 |
| 10 | 7.61 | 71.19 | 1091.79 | 3.28 | 8.42 |

**Table 5-16 Top Ten TRP Configurations for Market Rules according to rank of 'false' Payback Period**

| TRP Rank | No. of circuits (DCA / SCA / UPG) | Total OHL / UGC route length to be reinforced (km) | Maximum reinforcement capacity (MVA; type; generation zone) | Max Line Loading (%) | Mean Line Loading (%) |
|---|---|---|---|---|---|
| 1 | 50 / 52 / 83 | 3056.5 / 129.10 | 3819 ; UPG ; 9 | 81.14 | 27.73 |
| 2 | 42 / 50 / 88 | 3074.2 / 129.10 | 3819 ; UPG ; 9 | 83.09 | 28.24 |
| 3 | 51 / 51 / 86 | 3074.2 / 129.10 | 3819 ; UPG ; 9 | 83.85 | 27.73 |
| 4 | 57 / 55 / 85 | 3056.5 / 129.10 | 3798 ; DCA ; 9 | 83.25 | 27.12 |
| 5 | 66 / 65 / 87 | 3106.1 / 129.10 | 3819 ; UPG ; 9 | 83.27 | 26.40 |
| 6 | 58 / 64 / 94 | 3624.3 / 151.31 | 3798 ; DCA ; 9 | 82.61 | 26.97 |
| 7 | 79 / 67 / 96 | 3624.3 / 151.31 | 3712 ; DCA ; 7 | 80.41 | 25.74 |
| 8 | 62 / 67 / 98 | 3624.3 / 151.31 | 3801 ; SCA ; 9 | 76.20 | 26.28 |
| 9 | 59 / 82 / 161 | 6159.4 / 217.17 | 3819 ; UPG ; 9 | 78.75 | 25.78 |
| 10 | 59 / 85 / 162 | 6168.4 / 217.17 | 3819 ; UPG ; 9 | 83.30 | 25.99 |

occurs across the Penwortham-Kearsley double-circuit line; a key line for the transfer of generation down the west corridor in England.

The extent of onshore reinforcement required for the GB network to accommodate Market Rules is significant, however the overall route length of the base case network lines requiring reinforcement for the top eight ranked TRPs averages around 3417.48km (3280.05km OHL, 137.43km UGC). This is nearly three times the length required to accommodate Gone Green in 2020, however the time period between the year of the base case network and the scenario year is four times greater.

Similarly with the Gone Green scenario, the best performing TRP is not the least cost solution (see Table 5-15). As a result of the reduced constraint cost and outage cost associated with the plan, it can be concluded that a minimum investment cost of £3.92billion is required for the onshore GB transmission network to accommodate the Market Rules scenario in 2035; a cost which is around 160% greater than the minimum investment cost required to optimally accommodate Gone Green in 2020. However, according to the modelling approach proposed, a cost of up to £4.24billion (in particular) or a maximum of £12.26billion (in comparison to £4.08billion for Gone Green) is more likely to be required to efficiently accommodate generation for the scenario year and beyond.

## 5.4.2. Case Study 3: Results and Discussion for Central Co-ordination

The framework nondominated multi-objective results for the Central Co-ordination scenario are shown in the bi-objective plot in Figure 5-6. It was found that three nondominated TRP solutions (included and highlighted as a red dot in Figure 5-6) failed the security test (as detailed in section 4.9.) and have thus been excluded in the analysis of the results.

In comparison to Market Rules, to meet an electrical demand of 68.90GW for the Central Co-ordination scenario, the proposed generation mix (as detailed in Table 5-10) is estimated to require a CAPEX of between £2.10billion and £13.13billion, as opposed to between £3.58billion and £15.70billion for a demand of 79.57GW. By increasing network investment in this case (from £2.10billion to £13.13billion), annual line losses can be reduced by 5.32TWh, compared to 5.46TWh and 3.62TWh for Market Rules and Gone Green respectively; equating to an annual saving of £319.2million (using £60/MWh). Further it appears from Figure 5-6(a) and Figure 5-6(h) in particular, that a maximum limit of around 9TWh in annual line loss saving from the combined network (i.e. base case and TRP) can be achieved; compared to 12TWh for Market Rules. For the annual incremental O&M cost of a TRP and the resulting outage cost requirement, increasing network investment (from £2.10billion to £13.13billion) results in a potential increase from £0.64million to £9.76million (see Figure 5-6(b) and Figure 5-6(c)) and £31.27million to £1.31billion (see Figure 5-6(d)) respectively. For the outage cost evaluation in particular, the resulting costs from the nondominated solutions are often less than for Market Rules (between £136.79million and £1.97billion) and Gone Green (between £198.47million and £1.66billion).

An estimation of the Pareto front has been included in Figure 5-6(a), Figure 5-6(c) and Figure 5-6(d). In this case, from an investment cost of £2.10billion to £3.64billion, annual line losses can be reduced by 2.03TWh at a rate of 1.32GWh per £1million. However, between £3.64billion and £8.02billion and between £8.02billion and £13.13billion, annual line losses can only be reduced by 2.37TWh and 0.89TWh at a lower rate of 0.54GWh and 0.17GWh per £1million respectively. For the case of network outages from an investment cost of £2.65billion to £9.75billion, outage costs increase by £173.74million at a rate of only £24.47k per £1million of network investment. However, from £9.75billion to £13.09billion, outage costs increase by £393.61million at a greater rate of 117.85k per £million of network investment.

Overall with each additional £1million expenditure on the GB onshore transmission network, from an initial outlay of £2.10billion, a further upfront cost of £116k for network outages could be required and an increased annual cost saving of only £28k (again reduced slightly to

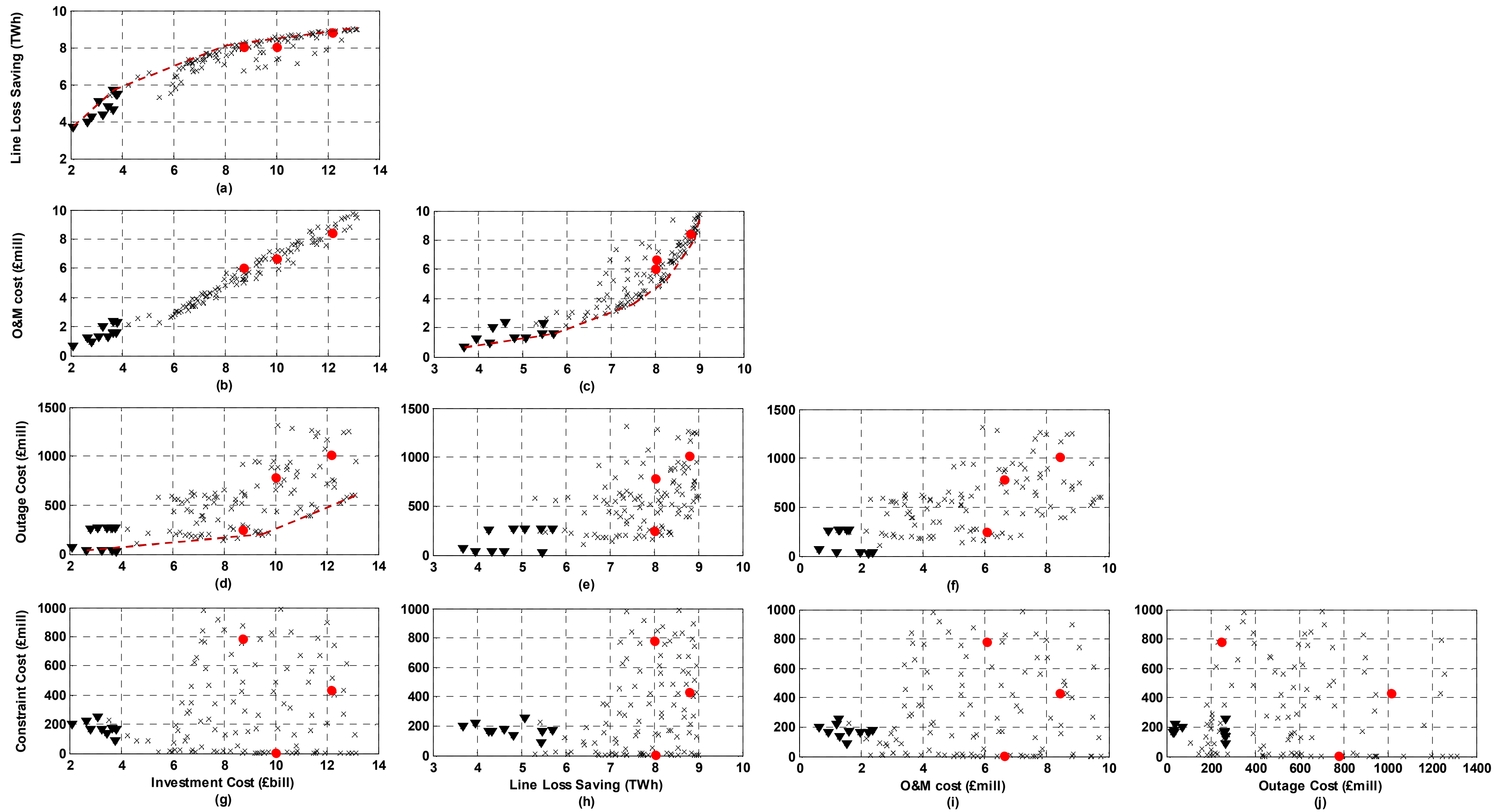


Figure 5-6 MOTREP framework nondominated multi-objective results for the Central Co-ordination scenario in 2035

consider the minimal increase in incremental O&M cost) from reducing line losses could be achieved. Compared to Market Rules and Gone Green, this annual cost saving is an improved justification for further network expansion, where in this case it is estimated to take around only 4 years, as opposed to 9 or 7 years respectively, for the estimated savings to recuperate the upfront outage cost. However, for an investment cost of up to £3.64billion, each additional £1million expenditure could require an increased upfront cost of only £24.47k for network outages, and achieve an improved further annual cost saving of £78k (reduced slightly according to the minimal increase in incremental O&M cost). For an investment cost of up to £8.02billion, each additional £1million expenditure could achieve an increased annual cost saving of £32k, for the same upfront cost (£24.47k). Hence, excluding the economic savings from alleviating annual congestion, network investment above £2.10billion – up to £3.64billion or a maximum of £8.02billion (compared to £4.24billion and £12.26billion respectively for Market Rules) – is advised for Central Co-ordination to further compensate for upfront outage costs.

As is the case for Market Rules in 2035, constraint cost is analysed in the multi-objective problem as opposed to constraint cost saving. The nondominated TRP solutions shown in Figure 5-6 result in an annual constraint cost for Central Co-ordination from as little as £0.06million to £986.10million (a similar constraint cost as estimated for the base case network under the Gone Green scenario). The constraint cost of many TRPs for Central Co-ordination is significantly less than for Market Rules (ranging from £1.61million to £5.12billion) and this is the result of the significant reduction in total electrical demand, and therefore supply associated with the scenario; Central Co-ordination (as detailed in Table 5-10) requires 18.38GW less supply capacity to meet a peak demand which is 10.67GW less than the peak demand for Market Rules.

For the reinforcement plans generated for Central Co-ordination, the peak constraint cost in low to medium evaluations of annual constraint cost was often located in the summer season, and was found to be almost double the peak constraint cost associated with the winter season. However, for higher evaluations of annual constraint cost the peak was often found in the summer outage season at around 5 times the winter season peak. Table 5-17 details the common seasonal constraint actions observed for Central Co-ordination as a result of the reinforcement plans in the nondominated set. In comparison to the constraint actions common for Gone Green and Market Rules, similarities only exist against Market Rules. Generation is

**Table 5-17 Common Seasonal Constraint Actions for Central Co-ordination, arising from Reinforcement Plans in the Nondominated Set**

| Generator Type | Power Station | Network Node(s) (Name/ID) | Constrained Off/On? |
|---|---|---|---|
| **Winter** | | | |
| Nuclear | Oldbury-on-Severn | OLDS10 / 643 | Off |
| CCGT (+CCS) | Seabank | SEAB40 / 718 | Off |
| Tidal | Severn Barrage | HINP40 / 421 ; SEAB40 / 718 | Off |
| CCGT (BL) | Marchwood | MAWO40 / 568 | On (from zero) |
| CCGT (BL) | Severn | USKM20 / 837 | On (from zero) |
| **Summer** | | | |
| CCGT (+CCS) | Seabank | SEAB40 / 718 | Off |
| Tidal | Severn Barrage | HINP40 / 421 ; SEAB40 / 718 | Off |
| CCGT (BL) | Severn | USKM20 / 837 | On |
| CCGT (BL) | Marchwood | MAWO40 / 568 | On |
| CCGT (BL) | Damhead Creek | KINO40 / 497 | On |
| CCGT (+CCS) | Damhead Creek | KINO40 / 497 | On |
| **Summer Outage** | | | |
| Onshore Wind | Pentland Road, Isle of Lewis | ARMO10 / 23 | Off |
| Onshore Wind | South Muaitheabhal | ARMO10 / 23 | Off |
| Onshore Wind | Dumnaglass | BEAU40 / 42 | Off |
| Onshore Wind | Eishken Estate | BEAU40 / 42 | Off |
| Onshore Wind | Pairc | BEAU40 / 42 | Off |
| Onshore Wind | Ceannacroc | MILW1Q / 584 | Off |
| Onshore Wind | Strathy | STRW10 / 783 | Off |
| Marine (Tidal / Wave) | North of Scotland | DOUN20 / 221 | Off |
| CCGT (+CCS) | West Burton | WBUR40 / 852 | On (from zero) |
| CCGT (+CCS) | Knottingley | FERR4A / 317 | On (from zero) |

again constrained off during the year for this scenario from the Oldbury-on-Severn nuclear power station and marine generation sited in the north of Scotland (DOUN20). Hence, as well as the similarities observed in constrained off generation between Market Rules and Gone Green, it is clear that the current network may also need reinforced at these locations (subject to a detailed CBA) to ensure that local generation is unrestricted.

As with the Market Rules case study, trade-offs involving constraint costs are unclear (as can be seen in Figure 5-6(g)-(j)) and a 'false' assessment of $CC_{SAV}$ is again calculated using an adequate value for $CC_{ORIG}$ (in this case £1billion), to locate the top performing TRPs within the nondominated set (using (5-1)). The objective evaluations and configurations of the top ten ranked TRP solutions (as highlighted using a black triangle in Figure 5-6) with the lowest 'false' payback period for the Central Co-ordination scenario are detailed in Table 5-18 and Table 5-19 respectively.

Again (as can be seen in Table 5-19) in comparison to Market Rules and Gone Green, the most significant reinforcements (in terms of MVA capacity) in the top performing TRP solutions are required in generation zone 9. However, for this case study, in eight of the top ten TRPs the specific location of the most significant reinforcement occurs across circuits between Harker and Gretna on either side of the border (to the west) between Scotland and England. The circuits between each network node are crucial for the transfer of generation down the west corridor in England.

Due to the reduced demand and supply totals of the scenario, the extent of onshore reinforcement required for Central Co-ordination is less than Market Rules for the year 2035. Thus, the overall route length of the base case network lines requiring reinforcement for the top ten solutions averages around 2260.51km (2120.5km OHL, 140.01km UGC); a route length which is 34% less than the average route length of the top solutions for Market Rules.

**Table 5-18 Top Ten TRP Objective Evaluations for Central Co-ordination according to rank of 'false' Payback Period**

| TRP Rank | $IC_{TRP}$ (£billion) | $CC_{NEW}$ (£million) | $OC_{TRP}$ (£million) | $OM_{TRP}$ (£million) | $LL_{SAV}^{YEAR}$ (TWh) |
|---|---|---|---|---|---|
| 1 | 2.10 | 199.23 | 72.30 | 0.64 | 3.68 |
| 2 | 2.65 | 223.14 | 37.83 | 1.21 | 3.97 |
| 3 | 2.83 | 165.62 | 261.64 | 0.94 | 4.27 |
| 4 | 3.25 | 163.21 | 34.43 | 1.98 | 4.33 |
| 5 | 3.10 | 252.25 | 268.56 | 1.28 | 5.07 |
| 6 | 3.47 | 138.52 | 268.82 | 1.31 | 4.82 |
| 7 | 3.77 | 86.34 | 266.79 | 1.56 | 5.45 |
| 8 | 3.82 | 165.66 | 31.26 | 2.26 | 5.47 |
| 9 | 3.64 | 172.13 | 264.61 | 1.61 | 5.71 |
| 10 | 3.65 | 175.28 | 34.19 | 2.39 | 4.62 |

**Table 5-19 Top Ten TRP Configurations for Central Co-ordination according to rank of 'false' Payback Period**

| TRP Rank | No. of circuits (DCA / SCA / UPG) | Total OHL / UGC route length to be reinforced (km) | Maximum reinforcement capacity (MVA; type ; generation zone) | Max Line Loading (%) | Mean Line Loading (%) |
|---|---|---|---|---|---|
| 1 | 17 / 21 / 48 | 1715 / 135.76 | 3820 ; UPG ; 9 | 82.58 | 28.02 |
| 2 | 28 / 29 / 42 | 1715 / 135.76 | 3820 ; UPG ; 9 | 83.98 | 27.37 |
| 3 | 26 / 28 / 72 | 2524.6 / 144.25 | 3820 ; UPG ; 9 | 82.58 | 26.35 |
| 4 | 38 / 31 / 36 | 1715 / 135.76 | 3820 ; UPG ; 9 | 83.85 | 26.82 |
| 5 | 32 / 29 / 70 | 2524.6 / 144.25 | 3757 ; UPG ; 9 | 82.58 | 26.18 |
| 6 | 29 / 32 / 73 | 2531.6 / 144.25 | 3820 ; UPG ; 9 | 82.58 | 26.32 |
| 7 | 36 / 30 / 71 | 2524.6 / 144.25 | 3820 ; UPG ; 9 | 82.58 | 25.85 |
| 8 | 41 / 33 / 37 | 1715 / 135.76 | 3786 ; UPG ; 7 | 82.60 | 26.17 |
| 9 | 35 / 30 / 68 | 2524.6 / 144.25 | 3757 ; UPG ; 9 | 82.58 | 25.74 |
| 10 | 40 / 36 / 35 | 1715 / 135.76 | 3820 ; UPG ; 9 | 82.58 | 26.43 |

As a result of the reduced constraint costs and outage costs associated with the TRP solutions in the nondominated set for Central Co-ordination, these objectives have less economic bearing on the top performing solutions as defined by the 'false' payback period. Hence the top-ranking solution (as detailed in Table 5-18) is also the solution with the minimum associated investment cost. It can thus be concluded, according to the modelling approach proposed, that a minimum investment cost of £2.10billion is required for the onshore GB transmission network to accommodate the Central Co-ordination scenario in 2035. However, a cost of up to £3.64billion (in particular) or a maximum of £8.02billion is more likely to be required to efficiently accommodate generation for the scenario year and beyond.

## 5.5. *Scenario Conclusions from the MOTREP Framework*

Table 5-20 details a summary of the resulting CAPEX estimations generated from the MOTREP framework for the scenarios studied in this thesis. Central Co-ordination stipulates an assumed ACS peak demand of 68.9GW, which is around 10GW greater than Gone Green and around 10GW less than Market Rules. As all three scenarios are applied to the same base case network, it can be estimated using the framework that by reducing electrical demand by around 10GW from 69GW, the cost to reinforce the transmission network could be reduced by a minimum of £600million (at a rate of £60.61million/GW) and potentially £4.29billion (at a rate of £433.33million/GW), when analysing respectively the minimum and average CAPEX estimations obtained from the proposed modelling approach. Further, by reducing electrical demand by around the same amount from 79GW, it can be estimated that the cost of network reinforcement could be reduced by a minimum of £1.82billion (at a higher rate of £170.6million/GW) and potentially £2.35billion (at a lower rate of £220.24million/GW).

Through assessing the efficiency of each scenario to meet demand – by analysing the minimum and average CAPEX obtained from the proposed modelling approach on a per GW of demand

**Table 5-20 Scenario Summary of MOTREP framework CAPEX Estimations**

| Scenario | Demand (GW) | Supply (GW) | Min CAPEX (£billion) | Average CAPEX (£billion) | Min CAPEX Efficiency (£million / GW) | Average CAPEX Efficiency (£million / GW) |
|---|---|---|---|---|---|---|
| Gone Green | 59 | 101.8 | 1.5 | 4.28 | 25.42 | 72.54 |
| Central Co-ordination | 68.9 | 111.21 | 2.1 | 8.57 | 30.48 | 124.38 |
| Market Rules | 79.57 | 129.59 | 3.92 | 10.92 | 49.26 | 137.24 |

basis – conclusions can be reached on the economic effect, from a network perspective, of varying penetrations and types of renewable and conventional generation. Figure 5-7 details the trends in scenario efficiency for both the minimum and average CAPEX of each scenario. When extrapolating from the efficiency of Gone Green and Central Co-ordination, it is apparent that the generation mix of Market Rules is more inefficient at meeting the associated electrical demand from the perspective of minimum CAPEX, than the generation mix for Central Co-ordination. However, the generation mix of Central Co-ordination appears to be more inefficient at meeting demand than the mix for Market Rules when assessing average CAPEX.

In summary, when comparing the results of the MOTREP framework for Market Rules and Central Co-ordination in 2035, it can be concluded that a lower penetration (as a function of total supply) of generation from coal (with CCS) and offshore wind, and a higher penetration of nuclear generation (associated with Central Co-ordination in comparison to Market Rules) is potentially more beneficial, from the perspective of reducing network reinforcement, in supplying future electrical demand in the GB transmission network. When extrapolating from the first two points in Figure 5-7 for the trend in minimum CAPEX, it appears that the higher penetration of coal and offshore wind associated with Market Rules, leads to an increase from

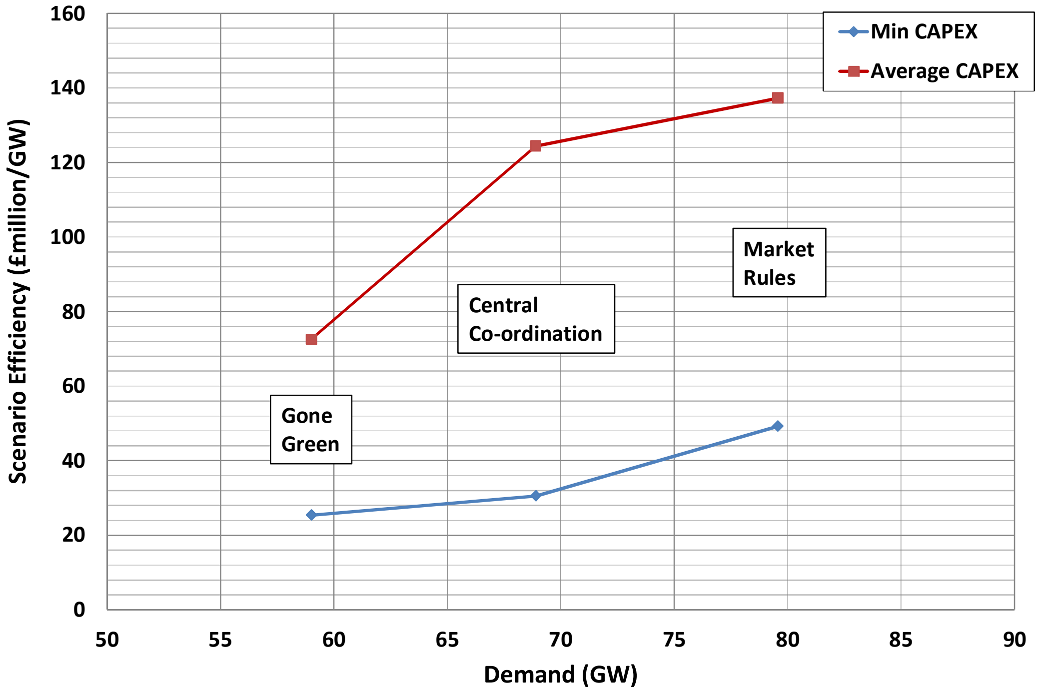


**Figure 5-7 Trends in scenario efficiency for electrical demand**

expectation (for the new demand value), of around £1.1billion in the minimum cost advised for network reinforcement (calculated using the extrapolated minimum CAPEX efficiency value of £35.5million/GW). It can also be concluded that the economic impact of the various demand reduction measures employed in Central Co-ordination by 2035, in comparison to Market Rules, is between £1.82billion and £2.35billion.

These conclusions are based primarily on the assumptions of the size and location of generating units and interconnectors made to construct the generation mix of each scenario (as detailed in Appendix C). The network related conclusions able to be formed from scenario analysis can be improved through applying the MOTREP framework to a wide range of scenarios.

The application of the proposed modelling approach to three published case studies for the UK system has been outlined in this chapter. The results from this analysis demonstrate the flexible and systematic approach of the MOTREP framework to evaluate scenarios and improve current understanding on the network related impact of demand reduction, and various penetrations in renewable and conventional generation, on the GB transmission system.

## 5.6. *Chapter 5 Summary*

This thesis proposes the use of an MOEA-based multi-objective transmission reinforcement planning framework to evaluate the thermal and economic impact of future energy scenarios to the GB transmission network. The design of the proposed framework is described in the previous chapter. This chapter presented the application of the MOTREP framework to three published case studies that are recent examples of future energy scenarios for the UK system; the Gone Green case study for the year 2020, and the Market Rules and Central Co-ordination case studies for the year 2035. The Gone Green case study was selected to test the current suitability of the framework through comparing cost savings of the top performing reinforcement plans subsequently generated, against the cost savings assessed by the GB SO from solutions created by the GB TNOs. The Market Rules and Central Co-ordination case studies were selected to demonstrate the flexibility of the modelling approach proposed for scenario evaluation.

The Gone Green case study demonstrated that the framework's systematic algorithm, which generates reinforcement solutions for a multi-voltage network, can produce plans that achieve similar cost savings to the solutions created by the GB TNOs. Further, it was demonstrated that trade-offs involving a number of the objectives can be defined by the framework, and can be used to identify scenario-related boundaries at which the CAPEX of network reinforcement should not be exceeded according to a cost benefit approach (which excluded constraint costs). However, as a result of increasing the size of the search space to consider varying locations, configurations and sizes of reinforcement and improving the temporal assessment of network congestion across the year – two mechanisms which enable the framework to create economically comparable reinforcement plans to the GB TNO solutions – trade-offs involving annual constraint costs could not be defined (for Gone Green or indeed the 2035 case studies) using the SPEA2.

The Market Rules and Central Co-ordination case studies aided in demonstrating the conclusions that could be formed via the framework for scenario analysis. From analysing the top performing reinforcement solutions generated by the modelling approach, a verdict (using in this case a measure/rank of payback period) on the minimum advised CAPEX for network reinforcement, to accommodate the energy scenario, was obtained. This verdict, including analysis into identified CAPEX boundaries for network reinforcement (via trade-off analysis) and the average CAPEX of the nondominated solutions, enabled informed economic conclusions to be made on the effect of the scenarios generation mix, and any demand reduction measures employed.

From the scenarios studied it was found that a lower penetration (as a function of total supply) of coal and offshore wind generation, and a higher penetration of nuclear generation, is potentially more beneficial from the perspective of the network, in supplying future electrical demand in the GB transmission network. Further, it was found that a significant economic saving in network reinforcement could therefore result from reducing system demand by around 10GW (13%).

In the next chapter the conclusions of this thesis are presented and the contributions to knowledge of this work are identified. Finally, further work beyond the contribution of this thesis is discussed.

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# Chapter 6

# 6. Conclusions, Contributions and Future Work

## 6.1. *Thesis Conclusions*

This chapter presents the conclusions of this thesis. These have been divided into three groups: conclusions from the literature review, conclusions from the design of the MOTREP framework and conclusions from the case studies. This chapter also summarises the contributions of this thesis, and proposes further work for the improvement and development of the framework presented in this thesis.

### 6.1.1. Conclusions from the Literature Review

Chapter 1 and Chapter 2 detailed the complex multi-objective nature of the transmission planning problem. The transmission planning problem was discussed in the context of the GB transmission network, and a debate on the methodology currently used by the GB SO and TNO to plan the system was included. The following key points were made:

- **Network reinforcement can have a wide range of technical and economic benefits/impacts.** Examples of technical drivers for reinforcement include: reliability through the minimisation of loss of load expectation and expected energy not supplied, or security through minimising voltage drop or maximising the level of deterministic security criterion adhered to (i.e. N-1 or N-2 contingency). Examples of economic drivers include: CAPEX reduction, a reduction in the cost of network outages and line losses, and the maximisation of cost savings from congestion alleviation. In a deregulated liberalised generation market, the alleviation of network constraints, the maximisation of network reliability, and the maximisation of social welfare are key objectives. A planning objective can thus be formulated from several perspectives related to a diverse set of stakeholders in transmission planning – the TNO, SO, system regulator and customer. Thus, it is widely regarded that **the transmission planning problem is a multi-objective problem.**

- The method used by the GB SO to assess reinforcements created by the GB TNOs, as with many traditional mathematical or heuristic techniques employed for transmission planning, involved the **conversion of the multi-objective transmission planning problem into a single-objective CBA optimisation**. Hence beneficial reinforcements were identified for the network **without fully exploring the complexity of the transmission planning problem and assessing the associated objective trade-offs**. This complexity arises in part, from the conflicting nature of the objectives considered and **a multi-objective analysis can be used to include these aspects**.

- **The methodology used by the GB SO and GB TNOs**, which splits the transmission system into zones and assesses network limitations and reinforcement benefits across the associated boundaries, **may not fully consider network constraints depending on the location of the constraint**. Further, the tool used by the GB SO to model constraint costs does not explicitly model the GB transmission system. **The creation of reinforcements and the CBA assessment is also currently separated** under the jurisdiction of the GB TNOs and SO respectively, although the GB SO can suggest reinforcements as part of its role as an 'enhanced' SO. **A combined approach to create and assess reinforcement proposals which fully considers network constraints could be beneficial to the GB TNOs and SO in economically planning a co-ordinated reinforcement strategy**.

The literature review in Chapter 2 into the current meta-heuristic frameworks for transmission planning in a deregulated environment – designed to include multi-objective analysis and combine the creation and assessment of network expansion proposals – showed that although approaches have been developed to optimally expand and reinforce a network, several limitations remain. These limitations are summarised as follows:

- **Only two decision variables were considered**: reinforcement location and configuration, which is restricted to single-circuit addition. However, **transmission reinforcement planning has a combination of decision variables**, which besides location and configuration, includes capacity (or size). Previous meta-heuristic approaches to multi-objective planning lacked alternative options for reinforcement or expansion of the network in the planning algorithm, often only including the option of line addition. However, in practice line reconductoring is a well-established cheaper alternative to line addition. Further, other options such as the use of FACTS devices exist potentially alleviating the need for line addition or upgrading. **A method that**

**can simultaneously optimise these decision variables to determine an economic reinforcement plan** will become a valuable tool for transmission network planning.

- **A limited and simplified temporal assessment of a reinforcement plans associated economical/technical impact on planning objectives related to a deregulated electricity market was included.** Reducing the simulation time of the framework was often seen as a priority. Network constraints were assessed at peak demand or at several points around peak demand. This assessment excludes high levels of network congestion which can often occur at low demand levels in the summer, due partly to planned outages of transmission lines. Further, as reinforcement plans are often designed to cater for peak demand it is important to assess the capability of a reinforcement against a different background of demand level and generation output. **An annual assessment**, **which includes planned summer outages of network assets, involving the evaluation of network constraints under differing levels of demand and stochastic outputs of generation needs to be incorporated into the approach** to provide an improved appraisal of a reinforcement plans impact and benefit to the network.

- **A simplified single-voltage small-scale network model was used as the background test case.** Hence the applicability of the method is not tested against a 'full-scale' transmission planning problem, and the complexities and limitations (i.e. power transfer capacity of the line) associated with each voltage level in a transmission system are therefore not considered. **A systematic transmission planning approach designed to be applied to and tested against a practical multi-voltage transmission network** would be a useful addition to the field of transmission network planning.

- **The alteration of an expansion/reinforcement plan during the optimisation, and the redesign and rearrangement of the associated reinforcements was not considered**. If line upgrading/reconductoring is included as a reinforcement option, the ability to redesign reinforcements is crucial, particularly for network plans which do not involve line addition. A reinforcement plan could exacerbate network issues, but a small adjustment to the plan could lead to a successful, potentially optimal, solution. **A systematic approach to initially generate individual reinforcements**

**(and overall plans) and to alter reinforcements should network issues arise is needed for the framework to adequately include line upgrading as an option, and to potentially improve the efficiency of the multi-objective optimisation.**

Due to the above limitations, **many of the meta-heuristic frameworks proposed in the literature for transmission planning under a deregulated environment do not adequately assess the trade-off between network investment cost and constraint cost alleviation; a key conflict**. Hence, the transmission planner is not sufficiently aided in better understanding this relationship, and the solutions produced may not be economically efficient on a practical system.

Further for the purposes of evaluating the impact of a future energy scenario to the GB transmission network, the review of influential UK low-carbon studies and associated models for scenario evaluation in Chapter 3 concluded the following:

- **A large number and variation of energy scenarios have been created for the UK energy system**; looking into a range of possible effects from the increased/decreased decentralisation of the power sector, and the associated increase/decrease in micro generation, to the increased deployment of smart grids or active network management schemes to balance increasing variable supply from renewable generation with elastic demand from the increased use of smart appliances or electric vehicles. Many of these scenarios are designed to meet future government environmental targets for 2020 and/or 2050, and scenario evaluation is often centred on the environmental aspects. However, **the effect of a scenario on the GB electrical transmission network and the reinforcement requirement to accommodate the scenario is often significantly simplified or overlooked**. Depending on the scenario the cost to reinforce the network could be significant, hence **a flexible framework is needed to analyse a wide range of scenarios** and provide feedback on the economic impact of each scenario to the GB network. This will aid policy makers in determining the best route forward to economically meet emissions targets.

Thus, an appropriate method is required to analyse the conflicting nature of the key impacts and benefits of network reinforcement. This method must adequately consider the annual impact of network reinforcement on system constraints, against a background of stochastic generation for varying levels of demand. The method is required to be systematic and flexible to create optimal reinforcement solutions for an increased array of decision variables, and to permit the analysis of a multitude of scenarios. Further, the method must be designed to be applied to, and tested against, a practical large-scale multi-voltage transmission network.

The work of this thesis develops such a framework which considers the above limitations in the associated design, and thereby improves on previous meta-heuristic approaches applied to a deregulated power system. The approach proposed is subsequently discussed.

### 6.1.2. Conclusions from the Design of the MOTREP Framework

This thesis proposes a flexible framework to evaluate the thermal and economic effect of applying a future energy scenario to the multi-voltage GB transmission network, through creating and locating an optimal set of transmission reinforcement plans for the multi-criteria problem relating, in this case, to the minimisation of investment cost, outage cost and annual incremental operation and maintenance cost, and the maximisation of annual congestion alleviation and line loss saving. The framework systematically constructs scenario-related reinforcements for a multi-voltage network and can therefore be used to evaluate a wide range of future energy scenarios. Further, the framework can consider, using parallel computation, a stochastic seasonal evaluation of each generated reinforcement plans impact on network congestion within the multi-criteria optimisation.

As such, the MOTREP framework combines for the first time an MOEA, a systematic planning algorithm – to construct and alter reinforcements – and a stochastic seasonal evaluation of network congestion as an objective function. Results from three case studies included in the thesis demonstrate that the framework can address the research questions proposed at the start of this thesis (section 1.2.), and that it is a valuable tool for network related scenario appraisal, for the reasons discussed next:

- **The systematic planning algorithm can construct a wide range of individual reinforcements of varying location, configuration and size. Resulting in a diverse set of reinforcement plans**. The algorithm can construct these plans to alleviate thermal congestion, subject to circuit capacity constraints for each voltage level in the network. Further, **the algorithm can alter the capacity and configuration of the associated reinforcements, as well as add reinforcements to the existing plan,**

**should the original solutions exacerbate thermal constraints**. This ensures that the original plan is given the opportunity to continue. The flexibility of the planning algorithm allows for reinforcements to be applied at many network locations. **Depending on the size of the network the envelope of reinforcement locations in which the MOEA can explore can be set**. Reinforcements can therefore not solely be applied to lines where thermal capacity is a pressing issue, and the search space of network solutions can be easily broadened to include potentially helpful solutions for the multi-objective problem of the framework.

- **The systematic planning algorithm takes into consideration the reinforcement options of line reconductoring, single-circuit addition and double-circuit addition as opposed to line addition only**, and creates suitable configurations for each location, subject to a right-of-way limit. **The systematic planning algorithm enables the framework to create its own candidate solutions for each reinforcement plan**. **This permits the framework to be applied to a wide range of scenarios, and enhances the multi-objective assessment carried out by the MOEA for scenario appraisal.**

- **MOEA techniques can deal explicitly with multiple objectives instead of aggregating to a single objective optimisation, as with traditional mathematical or heuristic techniques.** As mentioned previously, the transmission planning problem is multi-objective with a range of technical and economic drivers, and a diverse set of stakeholders. **An MOEA, with appropriate development, can explore the complexity of the transmission planning problem, explicitly visualising the benefits and impacts of network reinforcement and enabling solutions of compromise to be found**; in contrast, a single performance objective evaluation can obscure the analysis.

- The proposed framework uses the SPEA2 as the chosen MOEA. The first case study in Chapter 5 demonstrated that the SPEA2, in combination with the systematic planning algorithm, could generate transmission reinforcement solutions that have a similar impact on the transmission planning objectives analysed as solutions created by the GB TNOs for a similar case study. Thus, **the MOTREP framework has been**

**demonstrated to be able to assess reliably the thermal and economic impact of a future energy scenario to the GB transmission system**.

- For each case study, through use of an MOEA, a verdict (using in this case a measure/rank of payback period) on the minimum advised CAPEX for network reinforcement to accommodate the energy scenario, was obtained which considered the various reinforcement possibilities associated with different planning goals that may have been otherwise ignored. Further, trade-offs relating to several of the objectives could be identified using the SPEA2; resulting in the identification of CAPEX boundaries for the economic viability of network reinforcement (excluding constraint costs) beyond the minimum advised CAPEX. **The use of an MOEA therefore enables informed economic conclusions to be made**, in this case, on the effect of each scenarios generation mix and any demand reduction measures employed, as a result of each case study. **Consequently, the combination of the MOEA and a systematic planning algorithm enables a thorough optimisation of the configuration, location and size of network reinforcement to be performed simultaneously; an important and novel contribution.**

- The effect of network reinforcement in alleviating network congestion is a key technical and economic consideration, which needs to be adequately evaluated. Reinforcement plans are often designed to cater for conditions at peak demand of the system; hence an assessment of congestion alleviation around this time of the year leads to an overly positive outlook on the impact of the plan. Peak network congestion often occurs at lower demand levels during the summer season, where planned outages on the system exist and the type/output of contributory generation differs from the type/output on which the plan is designed against. **Planned outages of transmission lines are included in the summer when evaluating annual constraints**. For all three case studies in Chapter 5, the peak constraint cost located in the summer season was found to be at least double the peak constraint cost in the winter season, for each reinforcement plan generated by the MOTREP framework.

- An annual stochastic assessment of network congestion is required to provide an improved temporal and technical appraisal of a reinforcement plans impact and benefit. However, this assessment will take longer to evaluate. As an MOEA is utilised in the optimisation stage, computational efficiency in the evaluation of the chosen objectives is essential. **With the use of parallel computation, the framework can include within the multi-criteria optimisation a seasonal evaluation of network constraints against differing levels of demand and stochastic outputs of generation.** In the first case study of Chapter 5, it was demonstrated that the evaluation of annual constraint cost was similar to an evaluation carried out by the GB SO under a similar scenario for the same base case network. This provides confidence in the validity of the method employed and the inputs chosen.

- **The MOTREP framework is designed to be implemented on a large-scale multi-voltage network**, and includes constraints for each voltage level on the power transfer capacity of a line (incorporated into the systematic planning algorithm). The framework is designed to cope with the resultant levels of data relating to the network and the scenario generation mix.

- **The framework can perform a full spatial analysis on thermal constraints that exist on a large-scale network, and the reinforcement requirements to alleviate those constraints.** There is no geographical simplification of the network issues/solutions and the need for transmission reinforcement is not illustrated using network boundaries (which cross critical circuits for the security of the network) as used by the GB TNOs and SO. As a result of this spatial analysis, **similarities in constrained-off generation in the assessment of annual constraint costs can be located across generated reinforcement plans for different scenarios**. Hence, specific generating units which are likely to cause network issues in the future can be identified by the framework. Common constraint actions involving constrained-off generation were able to be located by the framework for the three case studies analysed in Chapter 5.

- **The framework is designed to be flexible and is based on a modular structure**. **Inputs to the framework can be easily varied, and the framework has been designed to allow for a degree in flexibility in each input.** Each step in the MOTREP framework is a module and the structure can incorporate other methods in the process. For example, **new methods can be easily included for the purposes of defining generation outputs, constructing/altering reinforcements or for security testing Pareto-optimal plans.** Further, **other objective evaluations can be easily incorporated**. As a result of adhering to rules defined in the NETS SQSS, the proposed framework is designed to be implemented on the GB transmission network. The EPTC method, used in the framework to satisfy (where applicable) the NETS SQSS, sets the output of contributory generating units as a basis for network reinforcement and is part of current planning practice in the UK. However, due to the modular structure employed, a new method can be used to replace the EPTC method and the framework could therefore **easily be adapted for practical application to other transmission systems**.

- **The optimisation stage of the framework is based on a generic MOEA structure** and each one of the MOEA steps is a module within the framework. The MOTREP framework proposed uses the SPEA2 operators for fitness assignment and truncation. **Other MOEA procedures for optimisation can be incorporated into the framework and tailored operators which, for example, differ from the adapted crossover and mutation procedures currently employed, can be developed and implemented in the framework for the transmission planning problem**. This flexibility enables a newly proposed MOEA technique to be incorporated which may outperform the SPEA2.

**The main impact of this thesis is that the developed framework can be utilised to evaluate a multitude of energy scenarios on a large scale multi-voltage transmission network.** As a result, the framework can be used to improve current understanding on the economic impact of a wide range of penetrations in renewable and conventional generation to the associated network. Also, the framework can therefore be used to assess the potential economic impact of reducing electrical demand on the system. This could guide governmental energy policy and ultimately TNO network investment.

**The main limitation of the proposed approach is that, despite the use of parallel computation in the assessment of network congestion, it is inherently computationally expensive**. To reduce the computational effort of the framework parallel computation can also be used in the assessment of outage cost. This aspect is suggested as further work (discussed later in this Chapter). The evaluation times can be significant depending on the case study. However, both scenario evaluation and transmission planning is not an “online” task and the framework optimisation can be performed in parallel to other studies and duties; for instance, in the creation and setup of the energy scenarios themselves prior to the application of the framework. Further **for transmission planning, the use of an MOEA, whilst causing an increase in the assessment time, can obtain results that otherwise would never have been considered.**

As a result of the expected evaluation times for problems of scale, limitations in design were required to improve computational efficiency. The framework utilises a DC power flow-based model of the GB network, excluding the voltage constraints associated with an AC power flow-based model. This is to avoid iteration in the calculation of network losses for every power flow calculation. Many DC power flow and DCOPF calculations are required throughout the framework process and a significant computational saving is achieved from this simplification. However, reinforcement options such as line upgrading/rebuilding to a new voltage level, line addition at a new voltage level, or the use of FACTS devices cannot therefore be adequately considered as their associated effect on the network cannot be adequately estimated. Further, network losses are estimated in the framework following a DCPF and are therefore not accurately assessed.

As well as the reinforcement options excluded due to the use of a DC power flow-base model, the installation of offshore HVDC/HVAC cables was not considered. **As the framework already explores varying locations, configurations, and capacity limits of network reinforcement, the addition of another configuration option, even one where the number of locations is restricted, would expand the search space and likely require a greater number of generations in the MOEA to improve the accuracy of the optimisation.** In turn this would increase the evaluation time of the framework. The use of ACPF and the addition of further reinforcement options are also suggested as further work and are discussed later in this Chapter.

A further simplification of the framework is the exclusion of network expansion to new network nodes for the connection of new generating units or demand sites. **The framework is designed to reinforce the onshore network** of a large-scale multi-voltage network. It was therefore assumed that **the bulk of the associated network CAPEX and interest in transmission planning in the UK lies with reinforcing the MITS, and not in the design of radial circuits for generation connection.** Further, offshore reinforcement to connect offshore generation is excluded and is assumed to fall under the remit of an offshore transmission owner (OFTO).

As a result of these simplifications and limitations in the MOTREP framework design, **multiple scenarios can be analysed in a realistic timeframe by the proposed approach**. The range of scenarios aids government energy policy in effectively defining the best scenario to economically meet emission targets. By utilising the MOTREP framework and comparing the results of the same year for future energy scenarios, **favourable scenarios from the perspective of the base case electrical transmission network can be readily identified**.

### 6.1.3. Conclusions from the Case Studies

The results from the case studies are discussed in Chapter 5. Although the results from the framework are related to specific UK energy scenarios, some general conclusions could be identified. The conclusions are:

- **A significant economic saving in network reinforcement could result from reducing electrical demand.** From the scenarios studied, a reduction of 10GW in demand on the GB transmission system from 69GW or 79GW could result in a network CAPEX saving of £4.29billion and £2.35billion respectively. These economic conclusions can be improved upon through the evaluation of a greater range of energy scenarios. **The framework proposed can be a useful tool to estimate the economic value of reducing demand in the future on the GB transmission network**.

- **Different penetrations of generator types (as a function of total supply) can result in significant economic savings**, according to an assessment carried out in Chapter 5 to determine the cost of network reinforcement per GW of electrical demand. From the scenarios studied it was found that a lower penetration of coal and offshore wind generation, and a higher penetration of nuclear generation, is potentially more beneficial from the perspective of the network in supplying demand on the GB transmission network. The framework can be used to quantify the economic savings which can result from harnessing a new generation mix, and through utilising a higher penetration of nuclear generation it was found that potentially a £1.1billion cost saving in network reinforcement could be achieved. **With each scenario studied, the framework can be used to form new and improved economic conclusions on the generator type penetrations associated with the scenario generation mix**.

- **The top performing reinforcement plans for the multi-objective problem often consisted of line upgrades as the significant component and largest single component, compared to single-circuit and double-circuit addition**. For the Central Co-ordination scenario in particular, the quantity of line upgrades applied in the top performing reinforcement plans was often found to be greater than the total quantity of line additions. This highlights the significance of including line reconductoring as an option in the planning algorithm.

- **Although trade-offs involving a few of the considered objectives could be defined using the framework, trade-offs associated with annual constraint costs could not be found.** This is a result of increasing the size of the search space for network reinforcement, and assessing network congestion at numerous points across the year – two mechanisms which have been proven to enable the framework to create economically comparable reinforcement plans to solutions created by the GB TNOs. These mechanisms are required to better simulate the planning problem, in particular, the conflict between CAPEX and the alleviation of network congestion. **This raises the question as to whether the SPEA2, or indeed another MOEA, can define trade-offs related to annual network congestion when including a wider search space of reinforcement options and a more detailed temporal assessment of constraints.**

## 6.2. *Contributions to Knowledge*

The following contributions of this thesis, in the order of chapter content, have been identified:

1. **It provides a detailed review on firstly the current methodology adopted by the GB TNOs and SO to plan the GB transmission network, and secondly, the recent meta-heuristic techniques and associated frameworks designed for multi-objective transmission planning under a deregulated environment (Chapter 2)**. The initial review in Chapter 2 highlights some of the limitations associated with the GB SO and TNOs approach for transmission planning under regulatory price control. A subsequent review then identifies some of the shortcomings associated with the design of the planning algorithms and frameworks employed which utilise a meta-heuristic for the purposes of performing a true multi-objective optimisation

considering a deregulated electricity market. Many of the limitations identified have been addressed by the proposed framework in this thesis. This review builds on previous transmission expansion planning reviews which offer a much higher level appraisal of the optimisation technique used and the problem formulation.

2. **It presents an updated review and discussion of influential UK low-carbon studies and the associated future energy scenarios, as well as the methods and models used for scenario creation and evaluation (Chapter 3)**. The review emphasises the extent and variation of the energy scenarios which now exist for the UK energy system, with a focus on the simplifications made, both technically and geographically, in evaluating the transmission network impact of the scenarios. This builds on a previous review which focused on the typology of major UK low carbon scenarios and the methodologies used for scenario building.

3. **It presents the design and development of a systematic and flexible framework to aid scenario assessment through evaluating the thermal and economic impact of a scenario on the large-scale, multi-voltage, GB transmission network (Chapter 4)**. Chapter 4 detailed the methods used within the framework of which the bulk of them are generic and can be applied to other transmission network planning problems. Further, the use of each planning attribute was discussed in detail. The design of the methods employed, and the practical details provided, are a contribution for future researchers in the fields of scenario evaluation and transmission network planning. The proposed framework can also be used for further research to potentially assess many more UK energy scenarios and improve the scenario-related conclusions generated in this thesis.

4. **It facilitates the understanding of MOEAs and their use in transmission planning (Chapters 4 and 5).** There is a lack of modelling approaches which utilise the SPEA2 algorithm for the transmission planning problem. The SPEA2 is widely regarded as being a successful MOEA technique, which has been used on a wide range of power system problems. Further, MOEAs in general are often not applied to a practical large-scale multi-voltage network. Chapter 4 presents the application of the SPEA2 to an enhanced transmission planning problem, discussing in detail the use of each SPEA2 procedure. Chapter 5 details the findings from the application of the framework and

the associated SPEA2 algorithm to three scenario case studies. From these case studies it was clear that the SPEA2 could not find trade-offs associated with the objective of minimising annual constraint costs. This is likely to be the result of carrying out an improved temporal assessment on annual constraints and including a larger search space of reinforcement options (as discussed previously) to generate economically viable reinforcement plans. This raises an important concern about the efficiency and robustness of the SPEA2 and potentially other MOEAs for solving the key complex conflict between investment cost and constraint cost saving experienced by the TNO and SO. This is a key contribution for the future use of these techniques in transmission network planning.

5. **It broadens the knowledge about the impacts and benefits of differing reinforcement options, scenario-related network reinforcement costs, the impact of various generation mixes to economically meet electrical demand in the UK system, and the potential economic impact of demand reduction (Chapters 4 and 5).**

    a. Chapter 4 discusses the calculation of each of the technical and economic planning attributes included in the proposed framework, and its use in transmission planning. This facilitates the further implementation of these attributes in other transmission planning approaches.

    b. Chapter 5 depicts nondominated reinforcement plans for three scenario case studies. The use of the multi-objective approach on an expanded search space of reinforcement options (with varying configurations, locations and sizes) aids in understanding better the complex relationship between the impacts and benefits of network reinforcement. For each case study it was found that line reconductoring was the dominant component to generate a top performing reinforcement plan.

    c. The use of multi-objective analysis for scenario evaluation enabled informed economic conclusions to be made on the impact of each scenario, and any demand reduction measures employed. For each scenario it was possible to locate a minimum advised CAPEX value and average value for network reinforcement, which considered a large range of reinforcement possibilities for different planning goals. Optimal penetrations of differing generator types could therefore be located through utilising the MOTREP framework on a multitude of scenarios, to reduce the CAPEX associated with transmission network reinforcement. This could aid governmental energy policy. Further, for each scenario CAPEX boundaries for the economic viability of network reinforcement (excluding constraint costs) beyond the minimum advised CAPEX, were able to be located which could aid TNOs in planning the network when the minimum CAPEX for reinforcement is unlikely to be achieved.

## 6.3. *Future Work*

Further work for the improvement and extension of the MOTREP framework developed in this thesis has been identified and is discussed below and summarised in Table 6-1.

The MOTREP framework, due to its ability to construct economically comparable reinforcement plans to solutions created by the GB TNOs, forms a good basis to analyse the economic impact of a multitude of scenarios. However, due to the use of DCPF/DCOPF the framework can only make suggestions to the TNO regarding scenario-related network reinforcement; involving the alleviation of thermal constraints only. Thus, a more detailed technical analysis using an AC power flow-based model of the GB network would need to be carried out by the TNO to include network losses, issues related to voltage magnitude and reactive power management.

Through including the extra constraints and considerations of the ACPF, the value of the MOTREP framework to the TNO and the economic evaluation of a scenario could be improved. Network data is available for the GB transmission network to enable the application of an ACPF [6.1]. Further, the reactive capability of each generating unit can be easily estimated. However, the evaluation time of an ACPF is much longer than a DCPF due to the iterative nature of the ACPF to calculate losses, and improvements to the framework would need to be made to reduce the overall computation time of the framework.

Options to reduce the computational time of the framework exist, ranging from the increased use of parallel computation in the framework – specifically in the evaluation of a reinforcement plans outage cost – to the use of a computationally efficient solver for AC optimal power flow (ACOPF).

**Table 6-1 A Summary of Suggested Further Work**

| Option | Procedure | Advantage | Disadvantage |
|---|---|---|---|
| Inclusion of ACPF. | Obtain added network data and adapt the encoded TRP matrix and systematic planning algorithm. Further, include the reactive power capability of generating units in the power flow. | Improve line loss calculation and include voltage constraints and reactive power management to better reflect the transmission planning problem. | Significant increase in the computation time of the framework. |
| Improvement in Framework Computational Efficiency. | Use parallel computation to best effect, and use an efficient solver for ACOPF (if using ACPF). | An improvement in computational efficiency. | A suboptimal plan for economically constraining on generation, in the assessment of annual constraint cost, may result from utilising a more efficient ACOPF solver. |
| Addition of Reinforcement Options. | Add FACTS devices, QB solutions and upgrades/line additions to a new voltage level (if using ACPF) as options in the systematic planning algorithm, and include candidate solutions for subsea HVDC/HVAC cables in each encoded TRP matrix. | A potential improvement in the evaluation of a scenario. The further inclusion of viable reinforcement types better reflects the complexity of the transmission planning problem. | An increase in the computation time of the framework as a result of enlarging the search space of reinforcement solutions. |
| Testing of other MOEAs or meta-heuristic techniques. | Alteration of optimisation procedures and operators. | Trade-offs related to annual constraint costs could be discovered; improving the scenario-related economic conclusions. Further, a more conclusive verdict can be reached on the applicability of meta-heuristic techniques in solving the associated objective conflicts. | An improved MOEA or meta-heuristic technique may not be found for the problem. |
| Inclusion of scenario impact on distribution network | A standardised small-scale GB distribution network model can be used to model the impact of a wide range of decentralised energy solutions and demand measures included in the scenario, and to assess the reinforcement requirement. This can be extrapolated to estimate the impact and reinforcement requirement on the full GB distribution system. | Adapting the framework to consider the impact of a scenario on the distribution network will enable the framework to better assess scenarios which envision an increasingly decentralised power system. | Increase in the computation time of the framework and the level of input data required. |

If ACPF is included without impacting too heavily on the computation time of the modelling approach, then additional options for network reinforcement can be incorporated into the framework and adequately assessed. Specifically, the inclusion of co-ordinated Quadrature Booster (QB) schemes, FACTS devices and offshore subsea HVDC/HVAC cables. Co-ordinated QB schemes are increasingly being used on the GB transmission network, and this allows control in the direction of active power flow onto lighter loaded circuits. FACTS devices are also increasingly being used in the GB transmission network (as evidenced by the reinforcements proposed by the GB TNOs in 2009 [6.2] and 2012 [6.3] for the Gone Green scenario) to increase the power transfer capacity of a transmission line restricted by voltage drop (as discussed in Chapter 1) without the need to upgrade or rebuild the line. This involves the use of series and/or shunt compensation on the line. The most common application in the GB transmission network is the addition of series compensation, which involves the connection of capacitors in series along the length of the line to compensate for inductance which causes the associated voltage drop, particularly on long heavily loaded lines.

Series compensation can be simulated in the network model for Matpower – the power systems analysis software used by the framework – by adding a generating unit at the sending end node (i.e. “from” bus) which is restricted to providing only reactive power; enough reactive power to accommodate the voltage drop of the line at the receiving end node (i.e. “to” bus). Within the framework, the systematic planning algorithm employed could be redesigned to potentially add series compensation as part of constructing the reinforcement plan; at locations where voltage drop is an issue. This can be done by adding generating units to represent the series compensation, which would then need to be specified for the plan. The systematic planning algorithm could then be adapted to include methodical protocols for altering the plan following a failure to adhere to network voltage constraints. To include offshore subsea HVDC/HVAC cables, generic candidate solutions would need to be created for the network and included in each encoded TRP matrix as an option for selection in the plan. An HVDC cable would need to be modelled correctly within the AC network model.

The addition of a reinforcement option would further expand the search space; increasing the computation time of the optimisation procedure in the framework. A reinforcement option would therefore need to have a significant effect on the output of the framework and the objective trade-offs to warrant inclusion. As an example, a test was carried out to consider the reinforcement options of line upgrading and line addition at a higher voltage level, where the voltage constraints on the reinforcement capacity were relaxed in the systematic planning algorithm and only a constraint existed on the maximum capacity of a circuit for the overall network. The framework was run for the case study involving the Gone Green scenario (the first case study in Chapter 5). However, the nondominated set of outputs from the MOTREP framework was found to be similar. Associated CAPEX costs for the new reinforcement options were excluded for simplicity, yet the lack of change in the remaining objectives considered suggested that the addition of the reinforcement options above would not be of significant benefit when utilising a DC power flow-base model of the GB system.

As well as including ACPF and additional reinforcement options, other MOEA's could be tested in the framework. As mentioned previously, the modular structure of the MOTREP framework allows other MOEA procedures for optimisation to be easily incorporated. The SPEA2 was found to be unsuccessful at discovering trade-offs associated with annual constraint costs. This was despite testing against different methods of crossover and mutation, as well as various crossover and mutation probabilities, archive sizes, population sizes and generation limits. Other MOEA procedures could be tested against the transmission planning problem proposed by the framework and a more informed conclusion could be made on the applicability of MOEA's for discovering the associated economic trade-offs. Alternatively, a whole new optimisation procedure built around the systematic planning algorithm of the framework could be introduced to incorporate a different meta-heuristic technique.

Currently, the MOTREP framework is best applied to scenarios which envision the continuation of 'big transmission' and a centralised power system. However, as evidenced in Chapter 3, several UK energy scenarios exist which envision a move toward a more decentralised system incorporating the increased use of active network management schemes – to maximise the output from an increasing pool of embedded renewable generation through the real-time balancing of generation and demand – smart domestic and industrial appliances to enable increased flexibility in electrical demand, and energy storage solutions to minimise the curtailment of renewable generation.

Incorporating the scenario impact on the distribution network will enable the proposed framework to consider the above technological innovations as well as the impact of solar PV, electric vehicles and plug in hybrid electric vehicles on peak and annual electrical system demand; both on the distribution and transmission network. This is as opposed to the current method of requiring an estimation of future peak demand on the transmission network, and utilising a load duration curve to estimate annual demand in the calculation of annual network constraint cost. Further, the framework could be adapted to also assess the network reinforcement requirement on the GB distribution network and therefore carry out a combined multi-objective power system reinforcement planning approach. This would enable an evaluation to be carried out on the overall network requirement of a scenario, and enable the framework to be suitably applied to a wider range of energy scenarios.

A standardised small-scale GB distribution network model, used to represent an average GB distribution network, could be used to model the impact of the various scenario-related decentralised strategies and assess the reinforcement requirement. The results of the study on the network model could be extrapolated to estimate the overall impact and reinforcement requirement on the full GB distribution system.

The development of the framework in some of these key directions would require further research which could be carried out as a doctoral or postdoctoral study.

## 6.4. *Thesis Conclusion*

This thesis proposes the use of a flexible multi-objective transmission reinforcement planning (MOTREP) framework to evaluate the thermal and economic impact of a future energy scenario to the GB transmission network. It presents the research, design and demonstration of the MOTREP framework, which is based on the use of a systematic planning algorithm, an MOEA, and an improved temporal, seasonal evaluation of network congestion. Reinforcement plans are generated by the proposed framework, which adhere (where possible) to current GB planning practice and can achieve similar cost savings for the multi-objective problem to solutions created by the GB TNOs. Results demonstrate that the framework is a valuable tool for use in the evaluation of a future energy scenario. The work presented in this thesis can be easily adapted for application to other large scale multi-voltage transmission networks.

## 6.4. *References for Chapter 6*


[6.1] National Grid. "*Electricity Ten Year Statement*", Appendix B, November 2014

[6.2] Electricity Networks Strategy Group, "*Our Electricity Transmission Network: A Vision for 2020 – Full Report*", Department for Energy and Climate Change, URN: 09D/717, July 2009

[6.3] Electricity Networks Strategy Group, "*Our Electricity Transmission Network: A Vision for 2020 – An Updated Full Report*", Department for Energy and Climate Change, URN: 11D/954, February 2012

# Appendix A: Background Framework Testing

In this appendix the background testing involved to determine firstly, the DCOPF solver to utilise for economically constraining on/off generation using piecewise linear cost functions, secondly, a generic rule for the number of outage groups to utilise in the outage cost evaluation, and finally, the number of DCOPF simulations, demand blocks and the length of the summer outage season to utilise in the constraint cost evaluation, is presented.

## A.1. *DCOPF Solver*

During the MOTREP framework process a significant number of DCOPF simulations are required; in particular to evaluate the outage cost and annual constraint cost (or saving) of a reinforcement plan. These DCOPF simulations involve the use of piecewise linear cost functions to estimate the cost of generation. As previously stated in Chapter 4, the framework utilises Matpower to carry out DCPF and DCOPF simulations, and several different solvers can be used through Matpower to resolve the proposed linear programming problem. Here, several of the solvers are tested against the objective of evaluating the constraint cost of a reinforcement plan, using the objective methodology detailed in Chapter 4. Each solver is therefore tested against the problem of economically constraining on/off generation. Table A-1 details the constraint cost evaluation of 15 reinforcement plans – generated by the framework (in this case) to accommodate the Central Co-ordination scenario (in the year 2035) on the 2014/15 base case GB transmission network – for a variety of applicable solvers. The following solvers were tested:

- **MIPS (Matlab Interior Point Solver) [A.1]** – a Matpower based primal/dual interior point solver.
- **Matlab Optimisation Toolbox**[13] – the Matlab optimisation toolbox includes solvers for linear programming, mixed-integer linear programming, quadratic programming, nonlinear optimisation, and nonlinear least squares. These solvers can locate optimal solutions to continuous and discrete problems. Here, the solver for linear programming (linprog) is tested when selecting this option.
- **MOSEK**[14] – a collection of optimisation tools that includes high-performance solvers for large-scale linear (as tested here) and quadratic programming problems.

[13] Details of the toolbox can be found at http://uk.mathworks.com/products/optimization/
[14] Available from: https://www.mosek.com/

- **IPOPT (Interior Point Optimizer)**[15] – a primal/dual interior point solver (like MIPS) primarily designed for large scale nonlinear optimisation.

It is clear from Table A-1 that MIPS continually appears to output the most economical plan for constraining on/off generation as a result of network constraints. However, the evaluation time of MIPS, for this large-scale problem, is significant compared to some of the other solvers. Utilising linprog in Matlabs optimisation toolbox would greatly reduce the evaluation time of the MOTREP framework however, as stated by Zimmerman *et al*. [A.1], while the solvers in the toolbox work reasonably well for very small systems, they do not scale well to larger networks. As shown in Table A-1, the output from the toolbox can be economically suboptimal (often significantly) in comparison to other solvers. The IPOPT solver on the other hand can generate similar plans of economic dispatch to MIPS; however, the evaluation time is slightly longer. MOSEK is the best alternative to MIPS, with a much-reduced evaluation time and similar plans for economic dispatch; however, the solver, more so than IPOPT, still occasionally generates substandard plans of economic dispatch compared to MIPS.

MIPS has been chosen in the MOTREP framework (and for the case studies carried out) to be used as the solver for DCOPF, as evaluation time is not a key issue when assessing a few UK energy scenarios. However, particularly for the case of scenarios in the year 2035 and 2050 –

**Table A-1 Constraint Cost Evaluation from a range of DCOPF Solvers**

| TRP ID | Constraint Cost according to DCOPF Solver (£mill) | | | |
|---|---|---|---|---|
| | MIPS | Matlab Optimisation Toolbox | MOSEK | IPOPT |
| 1 | 56.48 | 56.50 | 56.61 | 56.50 |
| 2 | 15.14 | 15.14 | 15.14 | 15.14 |
| 3 | 85.32 | 161.83 | 85.35 | 85.67 |
| 4 | 8.03 | 8.03 | 8.03 | 8.03 |
| 5 | 58.47 | 58.48 | 58.59 | 58.49 |
| 6 | 13.77 | 13.77 | 13.77 | 13.77 |
| 7 | 82.04 | 82.28 | 84.09 | 82.49 |
| 8 | 6.44 | 6.44 | 6.44 | 6.44 |
| 9 | 11.64 | 11.65 | 11.80 | 11.65 |
| 10 | 7.82 | 29.87 | 7.82 | 7.82 |
| 11 | 28.18 | 57.08 | 28.26 | 28.19 |
| 12 | 67.30 | 136.49 | 69.35 | 67.76 |
| 13 | 56.54 | 56.72 | 58.10 | 56.99 |
| 14 | 9.84 | 74.81 | 9.98 | 9.85 |
| 15 | 60.28 | 90.16 | 60.40 | 60.30 |
| **Average Result (£mill)** | **37.82** | **57.28** | **38.25** | **37.94** |
| **Average Evaluation Time (s)**[16] | **38.62** | **15.17** | **15.26** | **40.00** |

[15] Available from: https://projects.coin-or.org/Ipopt
[16] Based on the use of a 64-bit version of Matlab and an Intel i7-2600 3.4GHz central processing unit.

which require a greater number of outage groups to assess the outage cost of a reinforcement plan – if many scenarios are required to be analysed quickly, then MOSEK could be a preferred option. Further, it is unlikely that the optimal economic plan for constraining on generation could be achieved by the GB SO at every instance across the year and across the wider network. Hence, the deficiencies in the MOSEK output are reasonable and can be accommodated for in scenario evaluation.

## A.2. *Outage Group Rule*

As stated in Chapter 4, to assess the outage cost of a plan the MOTREP framework utilises a method (as detailed in section 4.7.3.) which involves splitting the reinforcement plan equally into several outage groups – a group of lines in the plan that are to be excluded from the base case network at the same time. The method involves iteratively assessing the economic impact of each outage group on constraining off generation in the base case network. The number of outage groups used in the assessment can therefore alter the simulation time and evaluation result. The more outage groups utilised, the greater the evaluation time and the more reduced the computational effort for assessing annual constraint costs would need to be to maintain the overall simulation time of the framework for scenario evaluation. The less outage groups utilised, the higher the risk of electrical islanding on the base case network, particularly for large reinforcement plans, and therefore the greater the risk of the DCOPF failing to converge.

Table A-2 details the result and evaluation time for a range of outage group quantities in the assessment of a reinforcement plans outage cost appraisal for the Gone Green (GG) and Central Co-ordination (CC) scenarios in the year 2020 and 2035 respectively. A greater number of thermal overloads in comparison to Gone Green resulted from applying Central Co-ordination to the base case network. Hence, reinforcement plans generated by the framework tended to be larger for Central Co-ordination. However, the scenario occurs 15 years after Gone Green and so the number of outage groups that can be accommodated in the period, from the base case year to the scenario year, is greater. For Gone Green and Central Co-ordination, the number of outage groups evaluated against therefore ranges from 2 to 20 and from 10 to 100 respectively.

The transmission plan generated for Gone Green consisted of reinforcements to 197 different network routes (97 double-circuit additions, 97 single-circuit additions and 117 upgrades);

**Table A-2 Outage Cost Evaluation and Assessment Time for Gone Green (in 2020) and Central Co-ordination (in 2035) under a range of Outage Group Quantities**

| Number of Outage Groups | | Outage Cost (£mill) | | Evaluation Time (s)[17] | |
|---|---|---|---|---|---|
| GG | CC | GG | CC | GG | CC |
| 2 | 10 | Error | 1494.92 | n/a | 0.74 |
| 4 | 20 | Error | 1149.12 | n/a | 2.44 |
| 6 | 30 | 989.10 | 927.15 | 0.35 | 4.42 |
| 8 | 40 | 977.52 | 804.29 | 0.58 | 6.49 |
| 10 | 50 | 952.44 | 686.69 | 0.77 | 8.78 |
| 12 | 60 | 849.70 | 502.05 | 0.92 | 11.02 |
| 14 | 70 | 743.33 | 286.72 | 1.42 | 13.98 |
| 16 | 80 | 833.18 | 494.85 | 1.59 | 16.41 |
| 18 | 90 | 756.18 | 173.04 | 1.91 | 17.34 |
| 20 | 100 | 828.68 | 207.92 | 2.10 | 20.30 |
| **Average Result (£mill)** | | 866.27 | 672.68 | | |

similar sizes of plan were not uncommon in the framework output for this scenario. When utilising 2 or 4 outage groups, electrical islanding of the network occurred and the DCOPF could not converge. Above 6 outage groups, the quantity of reinforcements within each group was small enough to avoid electrical islanding. For the benefit of being able to compare the outage cost associated with reinforcement plans of the same or a different scenario, a generic rule on the quantity of outage groups involved in the assessment needs to be defined and utilised by the framework.

When considering the average outage cost for Gone Green from the quantity of groups tested against in Table A-2, the use of 10 or 12 outage groups appears suitable. Considering the size of the reinforcement plans often generated by the MOTREP framework, it was decided that 10 outage groups should be used for Gone Green to better reflect the significant impact (both technical and therefore economical) on the base case network. Further, this is 6 outage groups larger than the cut-off (in this case) to avoid electrical islanding; allowing for a significant enough buffer to avoid an error in the DCOPF as a result of a larger reinforcement plan.

Taking the case for Gone Green, two outage groups per year from the base case year to the scenario year was therefore found to be suitable. Applying the same condition to Central Co-ordination resulted in an outage cost evaluation (resulting from 40 outage groups) that was often greater than the average experienced under a range of outage group quantities (as is the case in Table A-2). When considering the size of the reinforcement plans often generated for Central Co-ordination in comparison to Gone Green, it was clear that despite the difference in

[17] Based on the use of a 64-bit version of Matlab and an Intel i7-2600 3.4GHz central processing unit.

the scenario year an outage cost value of this size was required for a reliable assessment. For instance, the reinforcement plan for Central Co-ordination in Table A-2 consisted of reinforcements to 238 different network routes (120 double-circuit additions, 117 single-circuit additions and 138 upgrades); a 20.8% increase in size (in this case) from the plan for Gone Green. Further, the evaluation time for 40 outage groups is suitable considering the computational effort already used in the calculation of constraint cost. The outage group rule applied to Gone Green has therefore been used for all scenarios in this thesis to enable comparisons to be made on the associated impact and benefit of generated reinforcement plans for the same or a different scenario.

## A.3. *Inputs for Annual Constraint Cost Evaluation*

Several framework inputs (as detailed in Table 4-6 in Chapter 4) are required to assess the annual constraint cost of a reinforcement plan. Most of these inputs (i.e. offer/bid prices of generator types, or the probability distribution and mean availability for each generator type) can be easily defined using various sources of information. However, key inputs such as the number of DCOPF simulations, the number of demand blocks (to estimate the seasonal LDC) and the length of the summer outage season required to accurately assess annual network congestion are not so easily defined and can have a significant effect on the evaluation time and/or result of the assessment. Table A-3 details the annual constraint cost assessment which results for TRP 3 in Table A-1, under varying values for the three aforementioned inputs. The selected inputs for the case studies in this thesis are 100 DCOPF simulations, 8 demand blocks

**Table A-3 Constraint Cost Evaluation under varying Framework Inputs**

| 8 / 16 Outage Weeks | | Annual Constraint Cost (£mill) | | | | |
|---|---|---|---|---|---|---|
| | | Number of DCOPF simulations | | | | |
| | | **50** | **100** | **150** | **200** | **250** |
| **No. of Demand Blocks** | **4** | 137.94 / 12.31 | 103.35 / 154.22 | 67.51 / 157.19 | 72.24 / 106.97 | 108.44 / 13.92 |
| | **6** | 93.39 / 30.21 | 95.29 / 136.16 | 92.04 / 166.38 | 53.67 / 81.69 | 104.34 / 15.76 |
| | **8** | 77.70 / 18.24 | 85.32 / 137.38 | 76.16 / 182.13 | 41.31 / 98.50 | 114.42 / 15.22 |
| | **10** | 93.30 / 22.22 | 76.88 / 123.28 | 82.66 / 186.86 | 33.23 / 112.47 | 112.41 / 14.30 |
| | **12** | 30.22 / 12.02 | 90.17 / 123.64 | 87.98 / 198.88 | 23.87 / 126.52 | 116.86 / 14.40 |
| **Avg. Evaluation Time (s)[18]** | | **18.19** | **36.75** | **56.38** | **75.36** | **92.37** |

[18] Based on the use of a 64-bit version of Matlab and an Intel i7-2600 3.4GHz central processing unit.

and an 8-week summer outage season, which results in an annual constraint cost evaluation of £85.32million for TRP 3 (as shown in Table A-1).

In this case decreasing the number of demand blocks, particularly at low limits for the number of simulations, generally results in an increase in annual constraint cost; a potential consequence of under estimating electrical demand particularly for the winter and summer seasons. For Central Co-ordination in 2035 (and an assumed ACS peak demand value of 68.90GW) the use of 12 demand blocks results in an annual demand estimation (using the rectangular rule as illustrated in Figure 4-9 of Chapter 4) of 391.63TWh compared to 391.08TWh for 4 demand blocks. Further, this is the potential consequence of applying required constraint actions discovered in each block over a longer period due to the reduced number of simulations and the reduced number of demand blocks. However generally, when considering 8 weeks as the length of the summer outage season, the use of 250 DCOPF simulations for most quantities of demand block results in an increased assessment of annual constraint cost. Further, incidences of comparable objective values for the same number of demand blocks can be found from utilising less DCOPF simulations at a much-reduced evaluation time.

When considering 16 weeks as the length of the summer outage season from 100 to 200 DCOPF simulations, the effect on the objective evaluation is as expected; a significant rise (at an average increase of 117.50%). As stated in Chapter 5 and 6, reinforcement plans are often designed to cater for peak demand, hence network congestion often occurs at other points in the year where the demand level is lower and the type/output of contributory generation differs. Further, network congestion can also result from planned outages of transmission lines during low demand levels. Hence, by doubling the length and therefore extent of planned outages during low demand, a doubling of the annual constraint cost could be expected. However, curiously the effect of doubling the outage season length has the opposite outcome when utilising 50 or 250 DCOPF simulations.

Overall it is apparent that a wide variation in the assessment of annual constraint cost results from varying these three inputs, and the associated trade-offs are unclear. Hence, the inputs which result in the average objective evaluation from the parameters considered should be used to consider this variation. The average objective evaluation in Table A-3 is £86.63million. The closest evaluation to this is £85.32million, which results from using 100 DCOPF simulations (giving a reasonable evaluation time), 8 demand blocks and 8 weeks for the summer outage season. These inputs are selected for the case studies in this thesis and in addition to the other inputs results in a suitable constraint cost assessment of the base case 2014/15 GB transmission network; as concluded in Chapter 5.

## A.4. *References for Appendix A*


[A.1] Zimmerman, R.D., Murillo-Sánchez, C.E., "*Matpower 4.0: User's Manual*", Power Systems Engineering Research Center (PSERC), February 2011

# Appendix B: Assumed Zonal Wind Farm Correlations

In this appendix the distances assumed between generation zones, and the resultant assumptions of wind farm correlations between each zone in the calculation of annual constraint cost saving, for the case studies in this thesis, is disclosed. The generation zones used to split the network have been defined for the recent application of locational TNUoS charges. The distances (in km) between the central points of each zone were estimated using Google Earth Pro[19]. Table B-1 and Table B-2 detail the distances assumed and the corresponding correlations between each zone respectively. Figure B-1 shows the generation zones used in the calculation.

**Table B-1 Distance (km) between the central point of each zone**

| Zone | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | **0** | 117 | 124 | 123 | 219 | 185 | 269 | 304 | 426 | 367 | 500 | 519 | 510 | 613 | 691 | 738 | 757 | 761 | 766 | 817 |
| **2** | 117 | **0** | 213 | 138 | 272 | 180 | 262 | 326 | 391 | 314 | 495 | 510 | 466 | 568 | 669 | 688 | 696 | 715 | 737 | 810 |
| **3** | 124 | 213 | **0** | 111 | 109 | 150 | 211 | 212 | 376 | 342 | 418 | 441 | 464 | 565 | 616 | 698 | 724 | 711 | 698 | 728 |
| **4** | 123 | 138 | 111 | **0** | 136 | 62 | 146 | 193 | 304 | 251 | 380 | 399 | 389 | 492 | 568 | 620 | 639 | 640 | 643 | 697 |
| **5** | 219 | 272 | 109 | 136 | **0** | 127 | 139 | 108 | 293 | 283 | 314 | 338 | 378 | 477 | 512 | 610 | 643 | 619 | 599 | 621 |
| **6** | 185 | 180 | 150 | 62 | 127 | **0** | 89 | 146 | 240 | 194 | 321 | 339 | 326 | 430 | 506 | 558 | 580 | 579 | 582 | 637 |
| **7** | 269 | 262 | 211 | 146 | 139 | 89 | **0** | 88 | 165 | 145 | 236 | 253 | 252 | 354 | 422 | 487 | 513 | 501 | 498 | 553 |
| **8** | 304 | 326 | 212 | 193 | 108 | 146 | 88 | **0** | 197 | 215 | 206 | 230 | 280 | 374 | 405 | 507 | 544 | 513 | 489 | 517 |
| **9** | 426 | 391 | 376 | 304 | 293 | 240 | 165 | 197 | **0** | 95 | 147 | 144 | 87 | 190 | 280 | 321 | 350 | 338 | 346 | 428 |
| **10** | 367 | 314 | 342 | 251 | 283 | 194 | 145 | 215 | 95 | **0** | 239 | 240 | 156 | 255 | 372 | 375 | 391 | 402 | 428 | 523 |
| **11** | 500 | 495 | 418 | 380 | 314 | 321 | 236 | 206 | 147 | 239 | **0** | 31 | 166 | 216 | 200 | 339 | 388 | 333 | 289 | 317 |
| **12** | 519 | 510 | 441 | 399 | 338 | 339 | 253 | 230 | 144 | 240 | 31 | **0** | 149 | 187 | 174 | 309 | 359 | 302 | 259 | 300 |
| **13** | 510 | 466 | 464 | 389 | 378 | 326 | 252 | 280 | 87 | 156 | 166 | 149 | **0** | 104 | 226 | 233 | 262 | 251 | 274 | 382 |
| **14** | 613 | 568 | 565 | 492 | 477 | 430 | 354 | 374 | 190 | 255 | 216 | 187 | 104 | **0** | 168 | 134 | 173 | 149 | 187 | 324 |
| **15** | 691 | 669 | 616 | 568 | 512 | 506 | 422 | 405 | 280 | 372 | 200 | 174 | 226 | 168 | **0** | 214 | 276 | 181 | 90 | 157 |
| **16** | 738 | 688 | 698 | 620 | 610 | 558 | 487 | 507 | 321 | 375 | 339 | 309 | 233 | 134 | 214 | **0** | 62 | 54 | 168 | 333 |
| **17** | 757 | 696 | 724 | 639 | 643 | 580 | 513 | 544 | 350 | 391 | 388 | 359 | 262 | 173 | 276 | 62 | **0** | 109 | 228 | 394 |
| **18** | 761 | 715 | 711 | 640 | 619 | 579 | 501 | 513 | 338 | 402 | 333 | 302 | 251 | 149 | 181 | 54 | 109 | **0** | 120 | 285 |
| **19** | 766 | 737 | 698 | 643 | 599 | 582 | 498 | 489 | 346 | 428 | 289 | 259 | 274 | 187 | 90 | 168 | 228 | 120 | **0** | 165 |
| **20** | 817 | 810 | 728 | 697 | 621 | 637 | 553 | 517 | 428 | 523 | 317 | 300 | 382 | 324 | 157 | 333 | 394 | 285 | 165 | **0** |

**Table B-2 Calculated zonal wind farm output correlations**

| Zone | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1** | **1** | 0.66 | 0.65 | 0.65 | 0.56 | 0.59 | 0.51 | 0.48 | 0.38 | 0.43 | 0.33 | 0.32 | 0.32 | 0.26 | 0.22 | 0.20 | 0.19 | 0.19 | 0.18 | 0.16 |
| **2** | 0.66 | **1** | 0.56 | 0.63 | 0.51 | 0.59 | 0.52 | 0.46 | 0.41 | 0.47 | 0.33 | 0.32 | 0.35 | 0.29 | 0.23 | 0.22 | 0.22 | 0.21 | 0.20 | 0.17 |
| **3** | 0.65 | 0.56 | **1** | 0.66 | 0.66 | 0.62 | 0.56 | 0.56 | 0.42 | 0.45 | 0.39 | 0.37 | 0.35 | 0.29 | 0.26 | 0.21 | 0.20 | 0.21 | 0.21 | 0.20 |
| **4** | 0.65 | 0.63 | 0.66 | **1** | 0.64 | 0.71 | 0.63 | 0.58 | 0.48 | 0.53 | 0.42 | 0.40 | 0.41 | 0.33 | 0.29 | 0.26 | 0.24 | 0.24 | 0.24 | 0.21 |
| **5** | 0.56 | 0.51 | 0.66 | 0.64 | **1** | 0.65 | 0.63 | 0.67 | 0.49 | 0.50 | 0.47 | 0.45 | 0.42 | 0.35 | 0.32 | 0.26 | 0.24 | 0.26 | 0.27 | 0.25 |
| **6** | 0.59 | 0.59 | 0.62 | 0.71 | 0.65 | **1** | 0.69 | 0.63 | 0.54 | 0.58 | 0.46 | 0.45 | 0.46 | 0.38 | 0.33 | 0.29 | 0.28 | 0.28 | 0.28 | 0.25 |
| **7** | 0.51 | 0.52 | 0.56 | 0.63 | 0.63 | 0.69 | **1** | 0.69 | 0.61 | 0.63 | 0.54 | 0.52 | 0.53 | 0.44 | 0.38 | 0.34 | 0.32 | 0.33 | 0.33 | 0.29 |
| **8** | 0.48 | 0.46 | 0.56 | 0.58 | 0.67 | 0.63 | 0.69 | **1** | 0.58 | 0.56 | 0.57 | 0.55 | 0.50 | 0.42 | 0.40 | 0.32 | 0.30 | 0.32 | 0.34 | 0.32 |
| **9** | 0.38 | 0.41 | 0.42 | 0.48 | 0.49 | 0.54 | 0.61 | 0.58 | **1** | 0.68 | 0.63 | 0.63 | 0.69 | 0.58 | 0.50 | 0.46 | 0.44 | 0.45 | 0.44 | 0.38 |
| **10** | 0.43 | 0.47 | 0.45 | 0.53 | 0.50 | 0.58 | 0.63 | 0.56 | 0.68 | **1** | 0.54 | 0.54 | 0.62 | 0.52 | 0.42 | 0.42 | 0.41 | 0.40 | 0.38 | 0.31 |
| **11** | 0.33 | 0.33 | 0.39 | 0.42 | 0.47 | 0.46 | 0.54 | 0.57 | 0.63 | 0.54 | **1** | 0.75 | 0.61 | 0.56 | 0.57 | 0.45 | 0.41 | 0.45 | 0.49 | 0.47 |
| **12** | 0.32 | 0.32 | 0.37 | 0.40 | 0.45 | 0.45 | 0.52 | 0.55 | 0.63 | 0.54 | 0.75 | **1** | 0.62 | 0.59 | 0.60 | 0.48 | 0.43 | 0.48 | 0.52 | 0.48 |
| **13** | 0.32 | 0.35 | 0.35 | 0.41 | 0.42 | 0.46 | 0.53 | 0.50 | 0.69 | 0.62 | 0.61 | 0.62 | **1** | 0.67 | 0.55 | 0.54 | 0.52 | 0.53 | 0.51 | 0.42 |
| **14** | 0.26 | 0.29 | 0.29 | 0.33 | 0.35 | 0.38 | 0.44 | 0.42 | 0.58 | 0.52 | 0.56 | 0.59 | 0.67 | **1** | 0.60 | 0.64 | 0.60 | 0.62 | 0.59 | 0.46 |
| **15** | 0.22 | 0.23 | 0.26 | 0.29 | 0.32 | 0.33 | 0.38 | 0.40 | 0.50 | 0.42 | 0.57 | 0.60 | 0.55 | 0.60 | **1** | 0.56 | 0.50 | 0.59 | 0.68 | 0.62 |
| **16** | 0.20 | 0.22 | 0.21 | 0.26 | 0.26 | 0.29 | 0.34 | 0.32 | 0.46 | 0.42 | 0.45 | 0.48 | 0.54 | 0.64 | 0.56 | **1** | 0.71 | 0.72 | 0.60 | 0.45 |
| **17** | 0.19 | 0.22 | 0.20 | 0.24 | 0.24 | 0.28 | 0.32 | 0.30 | 0.44 | 0.41 | 0.41 | 0.43 | 0.52 | 0.60 | 0.50 | 0.71 | **1** | 0.66 | 0.55 | 0.41 |
| **18** | 0.19 | 0.21 | 0.21 | 0.24 | 0.26 | 0.28 | 0.33 | 0.32 | 0.45 | 0.40 | 0.45 | 0.48 | 0.53 | 0.62 | 0.59 | 0.72 | 0.66 | **1** | 0.65 | 0.50 |
| **19** | 0.18 | 0.20 | 0.21 | 0.24 | 0.27 | 0.28 | 0.33 | 0.34 | 0.44 | 0.38 | 0.49 | 0.52 | 0.51 | 0.59 | 0.68 | 0.60 | 0.55 | 0.65 | **1** | 0.61 |
| **20** | 0.16 | 0.17 | 0.20 | 0.21 | 0.25 | 0.25 | 0.29 | 0.32 | 0.38 | 0.31 | 0.47 | 0.48 | 0.42 | 0.46 | 0.62 | 0.45 | 0.41 | 0.50 | 0.61 | **1** |

[19] Mapping software available at: http://www.google.co.uk/intl/en_uk/earth/

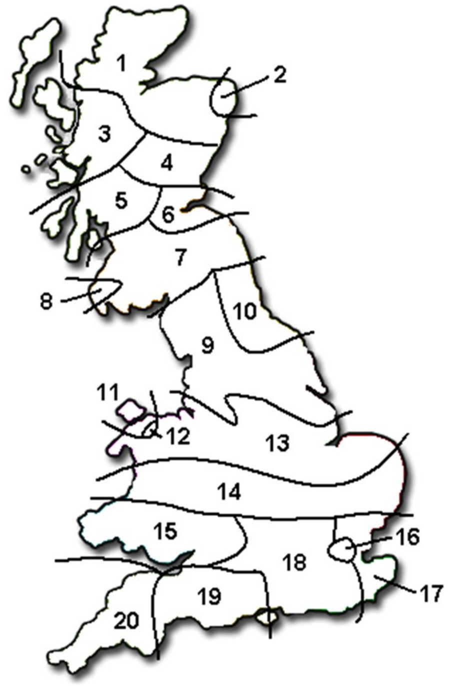


**Figure B-1 Generation Zones used to split the GB Transmission Network**

# Appendix C: Scenario Generation Mix Data

In this appendix a detailed list of the generating units/offshore arrays/interconnectors selected for each case study in this thesis is presented.

## C.1. *Gone Green – Year 2020*

The information used for creating the generation mix of the Gone Green scenario (developed in 2011 by National Grid) was obtained mainly from the NETS SYS [C.1]. Table C-1 details the options and selections made in the creation of the generation mix for year 2020 of the Gone Green scenario. The selections are made from the list of existing and contracted generating units/offshore arrays that are connected/likely to connect to the NETS according to the SYS. Network locations where scenario-related generation capacity is reduced are highlighted in red whilst locations where capacity is increased are highlighted in blue.

The generation projects outlined in Table C-1 signed a connection agreement (with the associated transmission licensee) prior to the publication of the NETS SYS. However, some of these projects may not progress to connection and/or the connection agreement might be altered or terminated. Hence it is assumed in the evaluation of the Gone Green scenario that all contracted generation outlined in the NETS SYS will be able to connect to the system. Table C-2 details the interconnector selections made for the scenario. In the first column of Table C-1 (as well as Table C-4 and Table C-5 for Market Rules and Central Co-ordination in Appendix C.2. and Appendix C.3.), if a generating unit is expected to operate at base load (BL or B) for the base case network and marginally (M) for the scenario year then a separate plant type identifier is used in the case study.

**Table C-1 Year 2020 Generating Unit selections for the Gone Green Scenario**

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| **Coal Generation** | | | | | | |
| IGCC | Hatfield | 800 | 800 | THOB40 | 2013/14 | n/a |
| BL | Aberthaw | 1665 | 1665 | ABTH20 | Connected | 1971 – 1979 |
| BL | Blyth | 0 | 0 | BLYT20 | 2020/21 | n/a |
| BL | Cottam | 2000 | 2000 | COTT40 | Connected | 1969 – 1970 |
| BL | Didcot A | 0 | 0 | DIDC40 | Connected | 1973 |
| BL | Drax | 3257 | 0 | DRAX40 | Connected | 1974 – 1986 |
| BL | Eggborough | 1940 | 1940 | EGGB40 | Connected | 1968 – 1969 |

| Plant Type | | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|---|
| M | | Ferrybridge | 1986 | 0 | FERR4A | Connected | 1966 – 1968 |
| BL | | Fiddlers Ferry | 1987 | 1987 | FIDF20_SPM | Connected | 1971 – 1973 |
| BL | | Ironbridge | 0 | 0 | IRON40 | Connected | 1970 |
| BL | | Kingsnorth | 0 | 0 | KINO40 | Connected | 1973 |
| M | | Lynemouth | 420 | 0 | BLYT20 | Connected | 1971 |
| BL | | Ratcliffe-on-Soar | 2021 | 2021 | RATS40 | Connected | 1968 – 1970 |
| M | | Rugeley | 1018 | 0 | RUGE40 | Connected | 1972 |
| BL | | Tilbury | 0 | 0 | TILB20 | Connected | 1968 – 1972 |
| BL | | Uskmouth | 363 | 363 | USKM20 | Connected | 2000 |
| BL | | Cockenzie | 0 | 0 | COCK20 | Connected | 1967 |
| BL | | Hunterston | 0 | 0 | HUER40 | 2018 | n/a |
| BL | | Longannet | 2284 | 2284 | LOAN20 | Connected | 1973 |
| B | M | West Burton | 1987 | 1484 | WBUR40 | Connected | 1967 – 1968 |
| **Total** | | | **21728** | **14544** | **Scenario Target: 14550MW** | | |
| | | | **Gas Generation** | | | | |
| BL | | Abernedd 1 | 435 | 435 | BAGB20 | 2013/14 | n/a |
| BL | | Abernedd 2 | 0 | 0 | BAGB20 | 2016/17 | n/a |
| BL | | Amlwch | 0 | 270 | WYLF40 | 2012/13 | n/a |
| BL | | Baglan Bay 1 | 552 | 552 | BAGB20 | Connected | 2002 |
| BL | | Baglan Bay 2 | 0 | 435 | BAGB20 | 2013/14 | n/a |
| BL | | Barking C | 470 | 470 | BARK40 | 2014/15 | n/a |
| BL | | Barry | 245 | 245 | ABTH20 / CARE20 | Connected | 1998 |
| BL | | Brine Field | 1020 | 1020 | THOR40 | 2014/15 | n/a |
| BL | | Carrington 2 | 0 | 0 | CARR40 | 2015/16 | n/a |
| BL | | CDCL | 395 | 395 | COTT40 | Connected | 2010 |
| BL | | Connahs Quay | 1380 | 1380 | DEES40 | Connected | 1996 |
| BL | | Coryton | 800 | 800 | COSO40 | Connected | 2000 |
| BL | | Damhead Creek | 805 | 805 | KINO40 | Connected | 2000 |
| BL | | Damhead Creek 2 | 0 | 0 | KINO40 | 2016/17 | n/a |
| BL | | Didcot B | 1550 | 1550 | DIDC40 | Connected | 1996 |
| BL | | Drakelow D | 1320 | 1320 | DRAK40 | 2014/15 | n/a |
| BL | | Enfield | 408 | 408 | BRIM2C_LPN / BRIM2D / BRIM2A_LPN / BRIM2B_LPN | Connected | 2010 |
| BL | | Grain | 860 | 860 | GRAI40 | Connected | 2010 |
| BL | | Grain 2 | 430 | 430 | GRAI40 | 2011/12 | n/a |
| BL | | Great Yarmouth | 420 | 420 | NORW40 | Connected | 2000 |
| BL | | Kings Lynn A | 340 | 340 | WALP40_EME | Connected | 1996 |
| BL | | Kings Lynn B | 981 | 981 | WALP40_EME | 2014/15 | n/a |
| BL | | Langage | 905 | 905 | LANG40 | Connected | 2008 |
| BL | | Marchwood | 900 | 900 | MAWO40 | Connected | 2008 |
| BL | | Medway | 700 | 700 | GRAI40 | Connected | 1995 |
| BL | | Partington | 910 | 910 | CARR40 | 2013/14 | n/a |
| BL | | Pembroke Stage 1 | 840 | 840 | PEMB40 | 2011/12 | n/a |
| BL | | Pembroke Stage 2 | 510 | 510 | PEMB40 | 2011/12 | n/a |
| BL | | Pembroke Stage 3 | 750 | 750 | PEMB40 | 2012/13 | n/a |
| BL | | Peterhead | 1180 | 1180 | PEHE20 | Connected | 2000 |
| M | | Rye House | 715 | 0 | RYEH40 | Connected | 1993 |
| BL | | Saltend | 1100 | 1100 | SAES20 | Connected | 1999 |
| BL | | Seabank | 1234 | 1234 | SEAB40 | Connected | 1998 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| BL | Seabank Ext. | 0 | 0 | SEAB40 | 2023 | n/a |
| BL | Severn Power 1 | 425 | 425 | USKM20 | Connected | 2010 |
| BL | Severn Power 2 | 425 | 425 | USKM20 | Connected | 2009 |
| BL | Shoreham | 420 | 420 | BOLN40 | Connected | 2000 |
| BL | South Holland | 840 | 840 | SPLN40 | 2013/14 | n/a |
| BL | South Humberbank | 1285 | 1285 | SHBA40 | Connected | 1996 |
| BL | Spalding | 880 | 880 | SPLN40 | Connected | 2004 |
| BL | Staythorpe C 1 | 425 | 425 | STAY40 | Connected | 2009 |
| BL | Staythorpe C 2 | 425 | 425 | STAY40 | Connected | 2009 |
| BL | Staythorpe C 3 | 425 | 425 | STAY40 | Connected | 2009 |
| BL | Staythorpe C 4 | 425 | 425 | STAY40 | Connected | 2009 |
| BL | Sutton Bridge A | 819 | 819 | WALP40_EME | Connected | 1998 |
| M | Teesside | 1875 | 0 | GRST20 | Connected | 1992 |
| BL | Thames Haven | 840 | 840 | COSO40 | 2014/15 | n/a |
| BL | Thorpe Marsh | 0 | 0 | THOM40 | 2016/17 | n/a |
| BL | Tilbury Stage 2 | 0 | 0 | TILB20 | 2016/17 | n/a |
| BL | West Burton B | 1370 | 1370 | WBUR40 | 2011/12 | n/a |
| BL | Wilton | 99 | 99 | GRST20 | Connected | 2006 |
| BL | Wyre Power | 0 | 0 | STAH40 | 2016/17 | n/a |
| OCGT | Cowes | 145 | 0 | FAWL40 | Connected | 1982 |
| OCGT | Didcot A | 0 | 0 | DIDC40 | Connected | 1968 - 1970 |
| OCGT | Indian Queens | 140 | 140 | INDQ40 | Connected | 1996 |
| OCGT | Taylors Lane | 144 | 0 | WISD20_LPN | Connected | 1979 - 1981 |
| M | Barking | 1000 | 0 | BARK20_LPN | Connected | 1994 |
| M | Brigg | 260 | 0 | KEAD40 | Connected | 1993 |
| M | Corby | 401 | 0 | GREN40_EME | Connected | 1993 |
| B M | Deeside | 515 | 515 | DEES40 | Connected | 1994 |
| B M | Keadby | 735 | 735 | KEAD40 | Connected | 1994 |
| M | Killingholme 1 | 900 | 0 | KILL40 | Connected | 1992 |
| M | Killingholme 2 | 665 | 0 | KILL40 | Connected | 1993 |
| B M | Little Barford | 665 | 665 | EASO40 | Connected | 1994 |
| M | Peterborough | 405 | 0 | WALP40_EME | Connected | 1993 |
| BL | Rocksavage | 810 | 810 | ROCK40 | Connected | 1997 |
| M | Roosecote | 229 | 0 | HUTT40 | Connected | 1991 |
| BL | Sutton Bridge B | 0 | 1305 | WALP40_EME | 2013/14 | n/a |
| **Total** | | **40147** | **35418** | **Scenario Target: 35510MW** | | |
| | | | **Nuclear Generation** | | | |
| EPR | Bradwell B | 0 | 0 | RAYL40 | 2021 | n/a |
| EPR | Dungeness C | 0 | 0 | DUNG40 | 2019 | n/a |
| EPR | Hinkley Point C 1 | 0 | 1670 | HINP40 | 2017/18 | n/a |
| EPR | Hinkley Point C 2 | 0 | 0 | HINP40 | 2018 | n/a |
| EPR | Oldbury C | 0 | 0 | OLDS10 | 2023 | n/a |
| EPR | Oldbury-on-Severn Power Station | 0 | 0 | OLDS10 | 2020 | n/a |
| EPR | Wylfa B | 0 | 1670 | WYLF40 | 2017/18 | n/a |
| EPR | Sizewell C 1 | 0 | 0 | SIZE40 | 2020 | n/a |
| EPR | Sizewell C 2 | 0 | 0 | SIZE40 | 2021 | n/a |
| AGR | Dungeness B | 1081 | 1081 | DUNG40 | Connected | 1985 – 1989 |
| AGR | Hartlepool | 1207 | 1207 | HATL20 | Connected | 1989 |
| AGR | Heysham | 2408 | 2408 | HEYS40 | Connected | 1989 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| AGR | Hinkley Point B | 1261 | 1261 | HINP40 | Connected | 1976 – 1978 |
| MX | Oldbury | 0 | 0 | OLDS10 | Connected | 1967 – 1968 |
| MX | Wylfa | 0 | 0 | WYLF40 | Connected | 1971 |
| APR | Wylfa C 1 | 0 | 0 | WYLF40 | 2020 | n/a |
| APR | Wylfa C 2 | 0 | 0 | WYLF40 | 2021 | n/a |
| APR | Wylfa C 3 | 0 | 0 | WYLF40 | 2022 | n/a |
| APR | Sizewell B | 1207 | 1207 | SIZE40 | Connected | 1994 |
| AGR | Hunterston | 1074 | 537 | HUER40 | Connected | 1964 |
| AGR | Torness | 1215 | 1215 | TORN40 | Connected | 1988 |
| **Total** | | **9453** | **12256** | **Scenario Target: 12320MW** | | |
| **Onshore Wind Generation** | | | | | | |
| n/a | Nant-Y-Moch | 0 | 176 | TRAW40 | 2015/16 | n/a |
| n/a | Carnedd Wen | 0 | 184 | TRAW40 | 2016/17 | n/a |
| n/a | Llanbrynmair South (added) | 0 | 110 | TRAW40 | 2015/16 | n/a |
| n/a | Rhigos | 299 | 299 | RHIG40 | 2012/13 | n/a |
| n/a | Aberchalder Cluster | 0 | 0 | FAUG20 | 2019 | n/a |
| n/a | Achruach | 50 | 50 | ACHR1Q / ACHR1R | 2013/14 | n/a |
| n/a | Braemore | 0 | 0 | SHIN10 | 2019 | n/a |
| n/a | Cairn Uish | 51 | 51 | DAAS20 | Connected | 2004 |
| n/a | Cairn Uish 2 | 41 | 41 | DAAS20 | 2013/14 | n/a |
| n/a | Coire Na Cloiche | 0 | 30 | ALNE1Q / ALNE1R | 2016/17 | n/a |
| n/a | Corrennie | 0 | 0 | TARL1Q / TARL1R | 2018 | n/a |
| n/a | Corriemollie | 0 | 0 | BEAU10 | 2019 | n/a |
| n/a | Dorenell | 0 | 0 | KEIT10 | 2019 | n/a |
| n/a | Drumnafunner | 0 | 0 | TARL1Q / TARL1R | 2018 | n/a |
| n/a | Dumnaglass | 0 | 0 | BEAU40 | 2018 | n/a |
| n/a | Forse | 0 | 0 | MYBS1Q / MYBS1R | 2018 | n/a |
| n/a | Glenmorie | 0 | 114 | SHIN10 | 2017/18 | n/a |
| n/a | Gordonstown Hill | 13 | 13 | KINT10 | 2011/12 | n/a |
| n/a | Halsary | 41 | 41 | MYBS1Q / MYBS1R | 2014/15 | n/a |
| n/a | Hanna | 0 | 0 | FWIL1Q / FWIL1R | 2018 | n/a |
| n/a | Hill of Fishrie | 0 | 0 | STRI1Q / STRI1R | 2018 | n/a |
| n/a | Hill of Towie | 48 | 48 | KEIT10 / MACD1Q | 2011/12 | n/a |
| n/a | Houstry Wind | 14 | 14 | DUBE1Q | Connected | 2004 |
| n/a | Invercassley | 0 | 50 | LAIR1Q | 2018 | n/a |
| n/a | Kilchattan | 0 | 0 | CAAD1Q / CAAD1R | 2019 | n/a |
| n/a | Loch Luichart | 51 | 51 | MOSS1Q / MOSS1R | 2013/14 | n/a |
| n/a | Pentland Road | 0 | 14 | ARMO10 | 2016/17 | n/a |
| n/a | Rosehall | 25 | 25 | SHIN10 | 2012/13 | n/a |
| n/a | Spittal Hill | 0 | 80 | MYBS1Q / MYBS1R | 2018 | n/a |
| n/a | Tofingall | 0 | 0 | MYBS1Q / MYBS1R | 2019 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Tom Nan Clach | 0 | 0 | INNE10 | 2019 | n/a |
| n/a | Viking Energy | 0 | 300 | BLHI20 | 2018 | n/a |
| n/a | An Suidhe | 21 | 21 | ANSU10 | Connected | 2010 |
| n/a | Ardkinglas | 19 | 19 | ARDK10 | Connected | 2008 |
| n/a | Aultmore | 60 | 60 | AULW1S | 2014/15 | n/a |
| n/a | Baillie & Bardnaheigh Wind | 53 | 53 | DOUN10 | 2012/13 | n/a |
| n/a | Beinn an Turic | 30 | 30 | CAAD1Q / CAAD1R | Connected | 2001 |
| n/a | Beinn an Turic 2 | 38 | 38 | CAAD1Q / CAAD1R | Connected | 2010 |
| n/a | Beinn Tharsuinn | 29 | 29 | ALNE1Q / ALNE1R | Connected | 2004 |
| n/a | Ben Aketil Wind | 28 | 28 | DUGR1Q | Connected | 2007 |
| n/a | Berry Burn | 73 | 73 | BLHI20 | 2013/14 | n/a |
| n/a | Black Craig | 40 | 40 | BLCR10 | 2014/15 | n/a |
| n/a | Black Craig 2 (added) | 0 | 90 | DUNO1Q / DUNO1R | 2014/15 | n/a |
| n/a | Boulfrich Wind (added) | 0 | 14 | DUBE1Q | Connected | 2010 |
| n/a | Boyndie Wind | 14 | 14 | KEIT10 / MACD1Q | Connected | 2005 |
| n/a | Braes of Doune | 74 | 74 | BRAC21 / BRAC22 | Connected | 2004 |
| n/a | Calliachar | 62 | 62 | CALW20 | 2014/15 | n/a |
| n/a | Camster | 63 | 63 | MYBS1Q / MYBS1R | 2012/13 | n/a |
| n/a | Careston (added) | 0 | 32 | BREC10 | 2015/16 | n/a |
| n/a | Carraig Gheal | 46 | 46 | FERO10 | 2012/13 | n/a |
| n/a | Causeymire | 55 | 55 | MYBS1Q / MYBS1R | Connected | 2004 |
| n/a | Clashindarroch Wind | 113 | 113 | CLAS20 | 2014/15 | n/a |
| n/a | Cruach Mhor | 30 | 30 | DUNO1Q / DUNO1R | Connected | 2004 |
| n/a | Deucheran Hill | 15 | 15 | CAAD1Q / CAAD1R | Connected | 2001 |
| n/a | Drumderg | 32 | 32 | COUA10 | Connected | 2007 |
| n/a | Dummuies | 12 | 12 | KEIT10 | Connected | 2010 |
| n/a | Dunbeath | 55 | 55 | KINT10 | 2014/15 | n/a |
| n/a | Edinbane Wind | 41 | 41 | EDIN10 | Connected | 2008 |
| n/a | Eishken Estate | 300 | 300 | BEAU40 | 2014/15 | n/a |
| n/a | Fairburn | 40 | 40 | ORRI1Q / ORRI1R | Connected | 2009 |
| n/a | Farr | 92 | 92 | FAAR1Q / FAAR1R | Connected | 2005 |
| n/a | Glens of Foundland Wind | 26 | 26 | KEIT10 / KINT10 | Connected | 2005 |
| n/a | Gordonbush Wind | 70 | 70 | GORW20 | 2011/12 | n/a |
| n/a | Griffin | 204 | 204 | GRIF1S / GRIF1T | 2011/12 | n/a |
| n/a | Kilbraur | 67 | 67 | STRB20 | Connected | 2007 – 2009 |
| n/a | Achany | 50 | 50 | LAIR1Q | Connected | 2009 |
| n/a | Mid Hill Wind | 75 | 75 | MIDH10 | 2013/14 | n/a |
| n/a | Millenium Wind | 65 | 65 | MILW1Q | Connected | 2007 – 2009 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Montreathmont Moor (added) | 0 | 40 | BRID1Q | 2014/15 | n/a |
| n/a | North Nesting Wind | 250 | 250 | BLHI40 | 2014/15 | n/a |
| n/a | Novar | 19 | 19 | ALNE1Q / ALNE1R | Connected | 1997 |
| n/a | Novar 2 | 32 | 32 | ALNE1Q / ALNE1R | 2011/12 | n/a |
| n/a | Pairc Wind | 94 | 94 | BEAU40 | 2014/15 | n/a |
| n/a | Paul's Hill Wind | 70 | 70 | GLFA10 | Connected | 2005 |
| n/a | Shira (added) | 0 | 52 | CLAC1Q | 2013/14 | n/a |
| n/a | Stacain | 43 | 43 | DALL20 | 2014/15 | n/a |
| n/a | Strathy North & South Wind | 226 | 226 | STRW10 | 2014/15 | n/a |
| n/a | Stroupster | 32 | 32 | THSO1Q / THSO1R | 2014/15 | n/a |
| n/a | Tangy Wind | 19 | 19 | CAAD1Q / CAAD1R | Connected | 2002 |
| n/a | Tomatin | 30 | 30 | BOAG1Q | 2013/14 | n/a |
| n/a | Tullo | 17 | 17 | BRID1Q / BRID1R | Connected | 2009 |
| n/a | Aikengall | 48 | 48 | DUNB1Q / DUNB1R | Connected | 2009 |
| n/a | Aikengall 2 | 108 | 108 | DUNB1Q / DUNB1R | 2013/14 | n/a |
| n/a | Black Law | 121 | 121 | BLLA10 | Connected | 2005 |
| n/a | Black Law Ext. | 69 | 69 | BLKX10 | 2013/14 | n/a |
| n/a | Bowbeat | 33 | 33 | KAIM20 | Connected | 2010 |
| n/a | Dun Law (added) | 0 | 30 | DUNE10 | Connected | 2008 |
| n/a | Dun Law Ext. | 30 | 30 | DUNE10 | Connected | 2010 |
| n/a | Galawhistle | 0 | 66 | COAL10 | 2018 | n/a |
| n/a | Kilgallioch | 0 | 274 | GLLU1Q / GLLU1R | 2017/18 | n/a |
| n/a | Rowantree | 67 | 67 | DUNE10 | 2014/15 | n/a |
| n/a | Afton | 68 | 68 | BLAC10 | 2014/15 | n/a |
| n/a | Andershaw | 45 | 45 | ANDE10 | 2012/13 | n/a |
| n/a | Arecleoch | 120 | 120 | AREC10 | Connected | 2010 |
| n/a | Auchencorth (added) | 0 | 45 | KAIM20 | Connected | 2010 |
| n/a | Barmoor (added) | 0 | 30 | BERW1Q / BERW1R | Connected | 2008 |
| n/a | Blackcraig | 0 | 71 | BLCW10 | 2015/16 | n/a |
| n/a | Brockloch Rig | 75 | 75 | DUNH1S / DUNH1T | 2014/15 | n/a |
| n/a | Clyde | 519 | 519 | CLYN2Q / CLYS2R | Connected | 2010 |
| n/a | Crystal Rig 1 | 63 | 63 | DUNB1Q / DUNB1R | Connected | 2003 |
| n/a | Crystal Rig 2 | 200 | 200 | CRYR40 | Connected | 2009 |
| n/a | Dalswinton (added) | 0 | 30 | DUMF10 | Connected | 2008 |
| n/a | Dersalloch | 69 | 69 | DESA1Q | 2014/15 | n/a |
| n/a | Drone Hill (added) | 0 | 38 | BERW1Q / BERW1R | Connected | 2008 |
| n/a | Earlsburn | 35 | 35 | BONN10 | Connected | 2006 |
| n/a | Earlshaugh | 108 | 108 | EHAU10 | 2014/15 | n/a |
| n/a | Ewe Hill | 66 | 66 | EWEH1Q | 2012/13 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Fallago | 144 | 144 | FALL10 | 2012/13 | n/a |
| n/a | Hadyard Hill | 117 | 117 | HADH10 | Connected | 2005 |
| n/a | Harestanes | 140 | 140 | HARE10 | 2013/14 | n/a |
| n/a | Harrows Law | 43 | 43 | HALA10 | 2013/14 | n/a |
| n/a | HearthStanes B | 81 | 81 | HEAR10 | 2014/15 | n/a |
| n/a | Kyle (added) | 0 | 300 | KYLN10 | 2011/12 | n/a |
| n/a | Longpark | 38 | 38 | GALA10 | Connected | 2009 |
| n/a | Margree | 0 | 43 | MARG10 | 2015/16 | n/a |
| n/a | Mark Hill | 56 | 56 | MAHI20 | Connected | 2010 |
| n/a | Minsca | 38 | 38 | CHAP10 | Connected | 2007 |
| n/a | Neilston | 80 | 80 | NEIW10 | 2012/13 | n/a |
| n/a | Newfield | 60 | 60 | NEWF1Q | 2012/13 | n/a |
| n/a | Pencloe | 63 | 63 | BLAC10 | 2014/15 | n/a |
| n/a | Toddleburn | 36 | 36 | DUNE10 | Connected | 2009 |
| n/a | Tormywheel | 32 | 32 | BAGA1Q / BAGA1R | 2012/13 | n/a |
| n/a | Ulzieside | 69 | 69 | GLGL1Q / GLGL1R | 2014/15 | n/a |
| n/a | Waterhead Moor | 72 | 72 | WAMR10 | 2014/15 | n/a |
| n/a | Whitelee | 592 | 592 | WHIL20 | Connected | 2007 – 2009 |
| **Total** | | **6962** | **9175** | **Scenario Target: 9150MW** | | |
| **Offshore Wind Generation** | | | | | | |
| Area | Bristol Channel | 302 | 1110 | ALVE40 | 2014/15 | n/a |
| Area | Burbo Bank | 0 | 0 | BIRK20 | Unknown | n/a |
| Area | Docking Shoal | 500 | 500 | WALP40_EME | 2011/12 | n/a |
| Area | Dogger Bank | 0 | 1000 | SAEN20 / SAES20 | 2016/17 | n/a |
| Area | Dudgeon | 0 | 1320 | NORW40 | 2015/16 | n/a |
| Area | Galloper | 0 | 0 | LEIS10 | Unknown | n/a |
| Area | Greater Gabbard | 500 | 1000 | LEIS10 | Connected | 2009 |
| Area | Gwynt Y Mor | 574 | 574 | GWYN40 | 2012/13 | n/a |
| Area | Hornsea | 500 | 1000 | KILL40 | 2014/15 | n/a |
| Area | Humber Gateway | 220 | 220 | HEDO20 | 2013/14 | n/a |
| Area | Irish Sea | 0 | 0 | WYLF40 / PENT40 / DEES40 | Unknown | n/a |
| Area | Lincs | 250 | 250 | WALP40_EME | 2011/12 | n/a |
| Area | London Array | 1000 | 1000 | CLEV40 | 2011/12 | n/a |
| Area | Navitas Bay Wind Park | 0 | 0 | MANN40 | Unknown | n/a |
| Area | Norfolk Bank | 0 | 2100 | BRFO40 | 2016/17 | n/a |
| Area | Ormonde | 150 | 150 | HEYS40 | 2011/12 | n/a |
| Area | Race Bank | 500 | 500 | WALP40_EME | 2013/14 | n/a |
| Area | Rampion | 0 | 0 | BOLN40 | Unknown | n/a |
| Area | Sheringham Shoal | 315 | 315 | NORW40 | Connected | 2010 |
| Area | Thanet | 201 | 201 | CANT40 | Connected | 2009 |
| Area | Triton Knoll | 0 | 0 | GRIW40 | 2018 | n/a |
| Area | Walney 1 and 2 | 364 | 364 | STAH40 | Connected | 2010 |
| Area | Walney Ext. | 0 | 0 | STAH40 | Unknown | n/a |
| Area | West of Duddon Sands | 333 | 333 | HEYS40 | 2013/14 | n/a |
| Area | Westermost Rough | 175 | 175 | HEDO20 | 2014/15 | n/a |
| Area | Beatrice | 400 | 1000 | BLHI20 | 2014/15 | n/a |
| Area | Moray Firth | 0 | 420 | PEHE20 | 2016/17 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| Area | Firth of Forth | 0 | 1778 | TORN40 | 2015/16 | n/a |
| Area | Argyll Array | 0 | 800 | DALL20 | 2016/17 | n/a |
| Area | Inch Cape | 0 | 0 | TORN40 | Unknown | n/a |
| Area | Islay | 0 | 0 | HUER40 | Unknown | n/a |
| Area | Neart na Gaoithe | 450 | 450 | CRYR40 | 2014/15 | n/a |
| **Total** | | **6734** | **16560** | **Scenario Target: 16560MW** | | |
| | | | **Hydro Generation** | | | |
| n/a | Aigas | 20 | 20 | AIGA1Q | Connected | Not Stated |
| n/a | Cashlie | 11 | 11 | KIIN10 | Connected | Not Stated |
| n/a | Ceannacroc | 20 | 20 | CEAN1Q | Connected | Not Stated |
| n/a | Clachan | 40 | 40 | CLAC1Q | Connected | Not Stated |
| n/a | Clunie | 61 | 61 | CLUN1S / CLUN1T | Connected | Not Stated |
| n/a | Culligran | 19 | 19 | CULL1Q | Connected | Not Stated |
| n/a | Deanie | 38 | 38 | DEAN1Q | Connected | Not Stated |
| n/a | Errochty | 75 | 75 | ERRO10 | Connected | Not Stated |
| n/a | Fasnakyle G1 & G3 | 46 | 46 | FASN20 | Connected | Not Stated |
| n/a | Fasnakyle G2 | 23 | 23 | FASN20 | Connected | Not Stated |
| n/a | Fasnakyle G4 | 8 | 8 | FASN20 | Connected | 2010 |
| n/a | Finlarig | 17 | 17 | FINL1Q | Connected | Not Stated |
| n/a | Glendoe | 100 | 100 | GLDO1G | Connected | Not Stated |
| n/a | Glenmoriston 1 | 37 | 37 | GLEN1Q | Connected | Not Stated |
| n/a | Glenmoriston 2 | 0 | 0 | GLEN1Q | 2019 | Not Stated |
| n/a | Grudie Bridge | 22 | 22 | ORRI1R | Connected | Not Stated |
| n/a | Inverawe | 25 | 25 | TAYN1Q / TAYN1R | Connected | Not Stated |
| n/a | Invergarry | 20 | 20 | INGA1Q | Connected | Not Stated |
| n/a | Kilmorack | 20 | 20 | KIOR1Q | Connected | Not Stated |
| n/a | Kinlochleven | 20 | 20 | KILO10 | Connected | 2001 |
| n/a | Livishie | 15 | 15 | GLEN1Q | Connected | Not Stated |
| n/a | Lochay | 47 | 47 | LOCH10 | Connected | Not Stated |
| n/a | Luichart | 34 | 34 | LUIC1Q / LUIC1R | Connected | Not Stated |
| n/a | Mossford | 19 | 19 | MOSS1Q / MOSS1R | Connected | Not Stated |
| n/a | Nant | 15 | 15 | LOCN1Q | Connected | Not Stated |
| n/a | Orrin | 18 | 18 | ORRI1Q / ORRI1R | Connected | Not Stated |
| n/a | Pitlochry | 15 | 15 | CLUN1S / CLUN1T | Connected | Not Stated |
| n/a | Quoich | 18 | 18 | QUOI10 | Connected | Not Stated |
| n/a | Rannoch | 45 | 45 | RANN1Q / RANN1R | Connected | Not Stated |
| n/a | Shin | 19 | 19 | SHIN10 | Connected | Not Stated |
| n/a | Sloy G1 & G4 | 73 | 73 | SLOY10 | Connected | Not Stated |
| n/a | Sloy G2 & G3 | 80 | 80 | SLOY10 | Connected | Not Stated |
| n/a | St Fillans | 17 | 17 | SFIL1Q | Connected | Not Stated |
| n/a | Torr Achilty | 15 | 15 | BEAU10 | Connected | Not Stated |
| n/a | Tummel | 34 | 34 | TUMB1Q / TUMB1R | Connected | Not Stated |
| n/a | Tongland | 33 | 33 | TONG10 | Connected | Not Stated |
| **Total** | | **1119** | **1119** | **Scenario Target: 1120MW** | | |
| | | | **Biomass Generation** | | | |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Portbury, Bristol | 0 | 0 | SEAB40 | 2013/14 | n/a |
| n/a | Anglesey Aluminium Power Station | 299 | 299 | WYLF40 | 2013/14 | n/a |
| n/a | Tees Renewable Energy Plant | 0 | 0 | LACK40 | 2014/15 | n/a |
| n/a | Port Talbot | 350 | 350 | MAGA20 | 2013/14 | n/a |
| n/a | Drax Renewable Power Station | 290 | 290 | DRAX40 | 2013/14 | n/a |
| n/a | Immingham Renewable Power Station | 0 | 0 | HUMR40 | 2014/15 | n/a |
| n/a | Port of Tyne Renewable Power Station | 0 | 0 | SSHI21 / SSHI22 | 2014/15 | n/a |
| n/a | Rothes Biopower Plant | 52 | 52 | GLRO20 | Connected | 2008 |
| n/a | Stevens Croft | 45 | 45 | CHAP10 | Connected | 2006 |
| **Total** | | **1036** | **1036** | **Scenario Target: 1040MW** | | |
| **Marine Generation** | | | | | | |
| Wave | Western Scotland | 0 | 0 | DALM2Q | Unknown | n/a |
| Wave | North Scotland | 0 | 0 | THSO1Q | Unknown | n/a |
| Wave | South West Wales | 0 | 0 | PEMB40 | Unknown | n/a |
| Wave | Cornwall | 0 | 0 | INDQ40 | Unknown | n/a |
| Tidal | Severn | 0 | 0 | HINP40 | Unknown | n/a |
| Tidal | Solway Firth | 0 | 0 | CHAP10 | Unknown | n/a |
| Tidal | Morecambe Bay | 0 | 0 | HEYS40 | Unknown | n/a |
| Tidal | Wash | 0 | 0 | SPLN40 | Unknown | n/a |
| Tidal | Humber | 0 | 0 | HUMR40 | Unknown | n/a |
| Tidal | Thames | 0 | 0 | COSO40 | Unknown | n/a |
| Tidal | Mersey | 0 | 0 | CAPE4A | Unknown | n/a |
| Tidal | Dee | 0 | 0 | DEES40 | Unknown | n/a |
| Tidal | Pentland Firth | 0 | 0 | THSO1Q | Unknown | n/a |
| Tidal | Between SW Scotland and Ireland | 0 | 100 | PORA1Q / PORA1R | Unknown | n/a |
| Tidal | Between SW Scotland and Isle of Man | 0 | 0 | GLLU1Q / GLLU1R | Unknown | n/a |
| Tidal | Angelsea | 0 | 0 | WYLF40 | Unknown | n/a |
| Tidal | South Isle of Wight | 0 | 860 | FAWL40 | 2018 | n/a |
| **Total** | | **0** | **960** | **Scenario Target: 960MW** | | |
| **Generation from CHP** | | | | | | |
| n/a | Derwent | 228 | 228 | WILE40 | Connected | 1994 |
| n/a | Fawley | 158 | 158 | FAWL40 | Connected | 1999 |
| n/a | Immingham | 1218 | 1218 | HUMR40 | Connected | 2004 – 2008 |
| n/a | Sellafield | 155 | 155 | HUTT40 | Connected | 1993 |
| n/a | Shotton | 210 | 210 | DEES40 | Connected | 2001 |
| n/a | Stoneywood Mills | 12 | 12 | DYCE1Q / DYCE1R | Connected | Not Stated |
| n/a | BP Grangemouth | 120 | 120 | GRMO20 | Connected | Not Stated |
| n/a | Exxon Mossmorran | 16 | 16 | MOSM10 | Connected | Not Stated |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Fife Energy | 123 | 123 | WFIE10 | Connected | 2000 |
| n/a | Chapelcross | 0 | 0 | CHAP10 | 2019 | n/a |
| n/a | Killoch | 0 | 0 | COYL20 | 2019 | n/a |
| **Total** | | **2240** | **2240** | **Scenario Target: 2240MW** | | |
| **Generation from Pumped Storage** | | | | | | |
| n/a | Dinorwig | 1644 | 1644 | DINO40 | Connected | 1983 – 1984 |
| n/a | Ffestiniog | 360 | 360 | FFES20 | Connected | 1961 – 1963 |
| n/a | Foyers | 300 | 300 | FOYE20 | Connected | Not Stated |
| n/a | Cruachan | 440 | 440 | CRUA20 | Connected | Not Stated |
| **Total** | | **2744** | **2744** | **Scenario Target: 2744MW** | | |

**Table C-2 Year 2020 Interconnector Selection for the Gone Green Scenario**

| Country | Capacity (MW) | Import (1) / Export (0) | Base Case (1 = Yes, 0 = No) | Scenario (1 = Yes, 0 = No) | Node(s) Name | Connection Date |
|---|---|---|---|---|---|---|
| France | 1988 | 1 | 1 | 1 | SELL40 | Connected |
| France | 2000 | 0 | 1 | 1 | SELL40 | Connected |
| France | 1000 | 1 | 0 | 0 | SELL40 | Unknown |
| France | 1000 | 0 | 0 | 0 | SELL40 | Unknown |
| Belgium (Nemo) | 1000 | 1 | 0 | 1 | CANT40 | 2019 |
| Belgium (Nemo) | 1000 | 0 | 0 | 1 | CANT40 | 2019 |
| Belgium (Belbrit) | 1000 | 1 | 0 | 0 | CANT40 | Unknown |
| Belgium (Belbrit) | 1000 | 0 | 0 | 0 | CANT40 | Unknown |
| Norway | 1400 | 1 | 0 | 1 | HAWP4A | 2018 |
| Norway | 1400 | 0 | 0 | 1 | HAWP4A | 2018 |
| Netherlands | 1200 | 1 | 1 | 1 | GRAI40 | Connected |
| Netherlands | 1200 | 0 | 1 | 1 | GRAI40 | Connected |
| Republic of Ireland | 500 | 1 | 1 | 1 | DEES40 | 2012 |
| Republic of Ireland | 500 | 0 | 1 | 1 | DEES40 | 2012 |
| Republic of Ireland 2 | 375 | 1 | 0 | 0 | PENT40 | Unknown |
| Republic of Ireland 2 | 375 | 0 | 0 | 0 | PENT40 | Unknown |
| Northern Ireland | 80 | 1 | 1 | 1 | AUCH20 | Connected |
| Northern Ireland | 500 | 0 | 1 | 1 | AUCH20 | Connected |
| **Total Imports**<br>**Total Exports** | | | **3768MW**<br>**4200MW** | **6168MW**<br>**6600MW** | **Target: 5590MW**<br>**n/a** | |

## C.2. *Market Rules – Year 2035*

Updated information was used from the 2012 ETYS [C.2] to create the generation mix of the Market Rules and Central Co-ordination scenarios developed by the 'Transition Pathways' consortium. As the generation mixes of the respective scenarios are designed to meet overall electrical demand, not reduced by contributions from embedded generation, assumptions on the likely transmission connected capacity for each generator type are required to be made to create a scenario-related generation mix for the transmission network. Table C-3 details the generation capacity connected to the transmission and distribution network for each transmission connected generator type according to the NETS SYS [C.1]. ETYS does not include information on distribution connected generation capacity. Embedded generation will generally consist of projects that are under 100MW capacity in NGET's area (England and Wales), 30MW in SPT's area (Southern Scotland) and under 10MW in SHE-T's area (Northern Scotland) [C.3].

Tables C-4 and C-5 below detail the options and selections made in the creation of the generation mix for year 2035 of the Market Rules and Central Co-ordination scenarios. Some generators identified previously in the NETS SYS have been excluded in the 2012 ETYS and replaced by new project proposals with new connection agreements. It is again assumed for the scenarios that all contracted generation will be able to connect to the system. Again, network locations where scenario-related generation capacity is reduced are highlighted in red whilst locations where capacity is increased are highlighted in blue. For each generator type, the target capacity required for the scenario is detailed and the target capacity for transmission connection – defined using the transmission connected percentages detailed in Table C-3 – is also detailed. By comparing the total capacity from the selections made for each generator type to the target for transmission connection, it is clear which generator types have been implicitly assumed to increase or decrease transmission network penetration from the base case outlined in Table C-3.

For the case of the Market Rules scenario, the interconnector selections chosen match those of the generation mix for the Gone Green scenario, as detailed in Table C-2; for Market Rules an overall interconnector import capacity of 6110MW is required. The selections and characteristics of generation from pumped storage are also identical between the two scenarios and in the Central Co-ordination scenario; hence this plant type is not included in Table C-4 and Table C-5. For power stations retrofitted with CCS, these plant types are initially identified as operating at base load (without CCS) in the base case network.

**Table C-3 2010/11 Generation Transmission and Distribution Connection by Plant Type**

| Plant Type | Transmission Connected | Distribution Connected |
|---|---|---|
| Coal | 28798MW (99.84%) | 47MW (0.16%) |
| CCGT | 29022MW (96.79%) | 961.2MW (3.21%) |
| OCGT | 579MW (67.68%) | 276.5MW (32.32%) |
| Nuclear | 10843MW (100%) | 0MW (0%) |
| CHP | 2240MW (57.07%) | 1685.3MW (42.93%) |
| Hydro | 1117MW (71.99%) | 434.7MW (28.01%) |
| Pumped Storage | 2744MW (100%) | 0MW (0%) |
| Biomass | 45MW (3.22%) | 1353.7MW (96.78%) |
| Onshore Wind | 2288MW (56.64%) | 1751.5MW (43.36%) |
| Offshore Wind | 1198MW (52.07%) | 1102.86MW (47.93%) |

**Table C-4 Year 2035 Generating Unit selections for the Market Rules Scenario**

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| | | | **Coal Generation** | | | |
| CCS | Aberthaw | 1665 | 1665 | ABTH20 | Connected | 1971 - 1979 |
| CCS | Blyth (added) | 0 | 1600 | BLYT20 | 2020 | n/a |
| CCS | Cottam | 2000 | 2000 | COTT40 | Connected | 1969 - 1970 |
| CCS | Fiddlers Ferry | 1987 | 1987 | FIDF20_SPM | Connected | 1971 - 1973 |
| CCS | Ratcliffe-on-Soar | 2021 | 1521 | RATS40 | Connected | 1968 - 1970 |
| CCS | Rugeley | 1018 | 1018 | RUGE40 | Connected | 1972 |
| CCS | Uskmouth | 363 | 363 | USKM20 | Connected | 2000 |
| CCS | Hunterston | 0 | 1650 | HUER40 | 2018 | n/a |
| CCS | Longannet | 2284 | 2284 | LOAN20 | Connected | 1973 |
| IGCC CCS | Hatfield | 0 | 800 | THOM40 | 2016 | n/a |
| BL | Drax | 3257 | 0 | DRAX40 | Connected | 1974 - 1986 |
| BL | Didcot A | 0 | 0 | DIDC40 | Connected | 1973 |
| BL | Ironbridge | 0 | 0 | IRON40 | Connected | 1970 |
| BL | Kingsnorth | 0 | 0 | KINO40 | Connected | 1973 |
| M | Lynemouth | 420 | 0 | BLYT20 | Connected | 1971 |
| BL | Cockenzie | 0 | 0 | COCK20 | Connected | 1967 |
| BL | Eggborough | 1940 | 0 | EGGB40 | Connected | 1968 - 1969 |
| M | Ferrybridge | 1986 | 0 | FERR4A | Connected | 1966 - 1968 |
| BL | West Burton | 1987 | 0 | WBUR40 | Connected | 1967 - 1968 |
| **Total** | | **20928** | **14888** | **Scenario Target: 14900MW Transmission Connected Target: 14876MW** | | |
| | | | **Gas Generation** | | | |
| CCS | Abernedd 1 | 0 | 470 | BAGB20 | 2015 | n/a |
| CCS | Abernedd 2 (added) | 0 | 435 | BAGB20 | 2016 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| CCS | Barking C | 0 | 470 | BARK40 | 2017 | n/a |
| CCS | Brine Field (added) | 0 | 1020 | THOR40 | 2014 | n/a |
| CCS | Carrington | 910 | 910 | CARR40 | 2014 | n/a |
| CCS | Cockenzie (added) | 0 | 1200 | COCK20 | 2035 | n/a |
| CCS | Damhead Creek 2 | 0 | 986 | KINO40 | 2016 | n/a |
| CCS | Drakelow D | 1320 | 1320 | DRAK40 | 2014 | n/a |
| CCS | Kings Lynn B | 0 | 981 | WALP40_EME | 2015 | n/a |
| CCS | Knottingley | 0 | 1500 | FERR4A | 2018 | n/a |
| CCS | Seabank | 0 | 824 | SEAB40 | 2023 | n/a |
| CCS | Spalding Ext. | 840 | 840 | SPLN40 | 2014 | n/a |
| CCS | Thames Haven | 840 | 840 | COSO40 | 2014 | n/a |
| CCS | Thorpe Marsh | 0 | 960 | THOM40 | 2016 | n/a |
| CCS | Tilbury C | 0 | 1800 | TILB40 | 2019 | n/a |
| CCS | Trafford | 0 | 1520 | CARR40 | 2018 | n/a |
| CCS | Wilton | 141 | 141 | GRST20 | 2014 | n/a |
| BL | Baglan Bay | 552 | 552 | BAGB20 | Connected | 2002 |
| BL | CDCL | 395 | 395 | COTT40 | Connected | 2010 |
| BL | Coryton | 800 | 800 | COSO40 | Connected | 2000 |
| BL | Damhead Creek | 805 | 805 | KINO40 | Connected | 2000 |
| BL | Enfield | 408 | 408 | BRIM2C_LPN / BRIM2D / BRIM2A_LPN / BRIM2B_LPN | Connected | 2010 |
| BL | Grain | 1290 | 1290 | GRAI40 | Connected | 2011 |
| BL | Great Yarmouth | 420 | 420 | NORW40 | Connected | 2000 |
| BL | Langage | 905 | 905 | LANG40 | Connected | 2008 |
| BL | Little Barford | 740 | 0 | EASO40 | Connected | 1994 |
| BL | Marchwood | 900 | 900 | MAWO40 | Connected | 2008 |
| BL | Pembroke | 2100 | 2100 | PEMB40 | Connected | 2011 |
| BL | Peterhead | 1180 | 1180 | PEHE20 | Connected | 2000 |
| BL | Severn Power | 850 | 850 | USKM20 | Connected | 2010 |
| BL | Shoreham | 420 | 420 | BOLN40 | Connected | 2000 |
| BL | Spalding | 880 | 880 | SPLN40 | Connected | 2004 |
| BL | Staythorpe C | 1728 | 1728 | STAY40 | Connected | 2010 |
| BL | West Burton B | 1305 | 1305 | WBUR40 | Connected | 2012 |
| M | Barking | 1000 | 0 | BARK40 | Connected | 1994 |
| M | Brigg | 260 | 0 | KEAD40 | Connected | 1993 |
| BL | Connahs Quay | 1380 | 0 | DEES40 | Connected | 1996 |
| M | Corby | 407 | 0 | GREN40_EME | Connected | 1993 |
| BL | Deeside | 515 | 0 | DEES40 | Connected | 1994 |
| BL | Keadby | 735 | 0 | KEAD40 | Connected | 1994 |
| M | Killingholme 1 | 900 | 0 | KILL40 | Connected | 1992 |
| M | Killingholme 2 | 665 | 0 | KILL40 | Connected | 1993 |
| BL | Kings Lynn A | 340 | 0 | WALP40_EME | Connected | 1996 |
| BL | Medway | 700 | 0 | GRAI40 | Connected | 1995 |
| M | Peterborough | 405 | 0 | WALP40_EME | Connected | 1993 |
| BL | Rocksavage | 810 | 0 | ROCK40 | Connected | 1997 |
| M | Roosecote | 229 | 0 | HUTT40 | Connected | 1991 |
| M | Rye House | 715 | 0 | RYEH40 | Connected | 1993 |
| M | Teesside | 45 | 0 | GRST20 | Connected | 1992 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| B M | Didcot B | 1550 | 1550 | DIDC40 | Connected | 1996 |
| B M | Barry | 245 | 245 | ABTH20 / CARE20 | Connected | 1998 |
| B M | Saltend | 1100 | 1100 | SAES20 | Connected | 1999 |
| B M | Seabank | 1234 | 1234 | SEAB40 | Connected | 1998 - 2000 |
| B M | South Humberbank | 1285 | 1285 | SHBA40 | Connected | 1996 |
| B M | Sutton Bridge | 819 | 819 | WALP40_EME | Connected | 1998 |
| OCGT | Barking (added) | 0 | 320 | BARK20_LPN | n/a | n/a |
| OCGT | Cowes | 145 | 0 | FAWL40 | Connected | 1982 |
| OCGT | Didcot A | 0 | 0 | DIDC40 | Connected | 1968 - 1970 |
| OCGT | Indian Queens | 140 | 0 | INDQ40 | Connected | 1996 |
| OCGT | Taylors Lane | 144 | 0 | WISD20_LPN | Connected | 1979 - 1981 |
| **Total** | | **35497** | **37708** | **Scenario Target: 38900MW Transmission Connected Target: 37651MW** | | |
| **Nuclear Generation** | | | | | | |
| EPR | Bradwell B | 0 | 0 | RAYL40 | 2021 | n/a |
| EPR | Dungeness C | 0 | 1650 | DUNG40 | 2018 | n/a |
| EPR | Hinkley Point C 1 | 0 | 1670 | HINP40 | 2017 | n/a |
| EPR | Hinkley Point C 2 | 0 | 1670 | HINP40 | 2018 | n/a |
| EPR | Moorside 1 | 0 | 0 | SELL40 | 2023 | n/a |
| EPR | Moorside 2 | 0 | 0 | SELL40 | 2025 | n/a |
| EPR | Oldbury C | 0 | 0 | OLDS10 | 2023 | n/a |
| EPR | Oldbury-on-Severn Power Station | 0 | 1600 | OLDS10 | 2020 | n/a |
| EPR | Sizewell C 1 | 0 | 1670 | SIZE40 | 2020 | n/a |
| EPR | Sizewell C 2 | 0 | 0 | SIZE40 | 2021 | n/a |
| APR | Sizewell B | 1212 | 1212 | SIZE40 | Connected | 1994 |
| APR | Wylfa C 1 | 0 | 1200 | WYLF40 | 2020 | n/a |
| APR | Wylfa C 2 | 0 | 0 | WYLF40 | 2021 | n/a |
| APR | Wylfa C 3 | 0 | 0 | WYLF40 | 2022 | n/a |
| AGR | Dungeness B | 1081 | 1081 | DUNG40 | Connected | 1985 - 1989 |
| AGR | Hartlepool | 1207 | 1207 | HATL20 | Connected | 1989 |
| AGR | Heysham | 2406 | 2406 | HEYS40 | Connected | 1989 |
| AGR | Hinkley Point B | 1261 | 644 | HINP40 | Connected | 1976 - 1978 |
| AGR | Hunterston | 1074 | 0 | HUER40 | Connected | 1964 |
| AGR | Torness | 1215 | 1215 | TORN40 | Connected | 1988 |
| MX | Oldbury | 0 | 0 | OLDS10 | Connected | 1967 - 1968 |
| MX | Wylfa | 0 | 0 | WYLF40 | Connected | 1971 |
| **Total** | | **9456** | **17225** | **Scenario Target: 17220MW** | | |
| **Onshore Wind Generation** | | | | | | |
| n/a | Achruach | 49.9 | 49.9 | ACHR1Q / ACHR1R | 2014 | n/a |
| n/a | Afton | 68 | 68 | BLAC10 | 2014 | n/a |
| n/a | Aikengall | 48 | 48 | DUNB1Q / DUNB1R | Connected | 2009 |
| n/a | Aikengall 2 | 108 | 108 | DUNB1Q / DUNB1R | 2014 | n/a |
| n/a | Allt Duine | 0 | 87 | BOAG1Q / BOAG1R | 2016 | n/a |
| n/a | An Suidhe | 20.7 | 20.7 | ANSU10 | Connected | 2010 |
| n/a | Andershaw | 45 | 45 | ANDE10 | Connected | 2012 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Ardkinglas | 19.25 | 19.25 | ARDK10 | Connected | 2008 |
| n/a | Arecleoch | 120 | 120 | AREC10 | Connected | 2010 |
| n/a | Auchencorth | 45 | 45 | KAIM20 | Connected | 2010 |
| n/a | Aultmore | 60 | 60 | AULW1S | 2014 | n/a |
| n/a | Baillie & Bardnaheigh Wind | 52.5 | 52.5 | DOUN10 | Connected | 2012 |
| n/a | Beinn an Turic | 30 | 30 | CAAD1Q / CAAD1R | Connected | 2001 |
| n/a | Beinn an Turic 2 | 43.7 | 43.7 | CAAD1Q / CAAD1R | Connected | 2010 |
| n/a | Beinn Tharsuinn | 29 | 29 | ALNE1Q / ALNE1R | Connected | 2004 |
| n/a | Ben Aketil Wind | 28 | 28 | DUGR1Q | Connected | 2007 |
| n/a | Benbrack and Quantans Hill | 0 | 72 | COYT1T | 2018 | n/a |
| n/a | Berry Burn | 72.5 | 72.5 | BLHI20 | 2013 | n/a |
| n/a | Black Craig | 40 | 40 | BLCR10 | 2013 | n/a |
| n/a | Black Law | 121 | 121 | BLLA10 | Connected | 2005 |
| n/a | Black Law Ext. | 69 | 69 | BLKX10 | 2013 | n/a |
| n/a | Blackcraig | 71.3 | 71.3 | BLCW10 | 2013 | n/a |
| n/a | Bowbeat | 33 | 33 | KAIM20 | Connected | 2010 |
| n/a | Boyndie Wind | 14.3 | 14.3 | KEIT10 / MACD1Q | Connected | 2005 |
| n/a | Braes of Doune | 74 | 74 | BRAC21 / BRAC22 | Connected | 2004 |
| n/a | Broadmeadows | 18 | 18 | GALA10 | Connected | 2012 |
| n/a | Brockloch Rig | 75 | 75 | DUNH1S / DUNH1T | 2014 | n/a |
| n/a | Burn of Whilk | 22.5 | 22.5 | MYBS1Q / MYBS1R | 2013 | n/a |
| n/a | Cairn Uish | 50.6 | 50.6 | DAAS20 | Connected | 2004 |
| n/a | Cairn Uish 2 | 41.4 | 41.4 | DAAS20 | 2013 | n/a |
| n/a | Calliachar | 62.1 | 62.1 | CALW20 | 2014 | n/a |
| n/a | Camster | 62.5 | 62.5 | MYBS1Q / MYBS1R | Connected | 2012 |
| n/a | Carnedd Wen | 0 | 150 | TRAW40 | 2016 | n/a |
| n/a | Carraig Gheal | 46 | 46 | FERO10 | Connected | 2012 |
| n/a | Carscreugh | 21.25 | 21.25 | GLLU1Q / GLLU1R | 2013 | n/a |
| n/a | Causeymire | 55.2 | 55.2 | MYBS1Q / MYBS1R | Connected | 2004 |
| n/a | Clashindarroch | 166.7 | 166.7 | CLAS20 | 2014 | n/a |
| n/a | Clyde | 521 | 521 | CLYN2Q / CLYS2R | Connected | 2010 |
| n/a | Coire Na Cloiche | 0 | 30 | ALNE1Q / ALNE1R | 2016 | n/a |
| n/a | Corriegarth | 49.9 | 49.9 | FOYE20 | 2014 | n/a |
| n/a | Corriemollie | 0 | 47.5 | BEAU10 | 2015 | n/a |
| n/a | Cour | 0 | 23 | CAAD1Q / CAAD1R | 2015 | n/a |
| n/a | Cruach Mhor | 29.75 | 29.75 | DUNO1Q / DUNO1R | Connected | 2004 |
| n/a | Crystal Rig 1 | 62.5 | 62.5 | DUNB1Q / DUNB1R | Connected | 2003 |
| n/a | Crystal Rig 2 | 200 | 200 | CRYR40 | Connected | 2009 |
| n/a | Dalswinton | 30 | 30 | DUMF10 | Connected | 2008 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Dersalloch | 69 | 69 | DESA1Q | 2013 | n/a |
| n/a | Deucheran Hill | 15 | 15 | CAAD1Q / CAAD1R | Connected | 2001 |
| n/a | Dorenell | 0 | 180 | KEIT10 | 2019 | n/a |
| n/a | Drumderg | 36.8 | 36.8 | COUA10 | Connected | 2007 |
| n/a | Dummuies | 12.3 | 12.3 | KEIT10 | Connected | 2010 |
| n/a | Dumnaglass | 0 | 99 | BEAU40 | 2018 | n/a |
| n/a | Dun Law Ext. | 30 | 30 | DUNE10 | Connected | 2010 |
| n/a | Dunbeath | 55 | 55 | KINT10 | 2014 | n/a |
| n/a | Earlsburn | 35 | 35 | BONN10 | Connected | 2006 |
| n/a | Earlshaugh | 0 | 108 | EHAU10 | 2015 | n/a |
| n/a | Edinbane Wind | 41.4 | 41.4 | EDIN10 | Connected | 2008 |
| n/a | Eishken Estate | 0 | 150 | BEAU40 | 2015 | n/a |
| n/a | Erica | 21.6 | 21.6 | BEAU10 | 2014 | n/a |
| n/a | Ewe Hill | 66 | 66 | EWEH1Q | Connected | 2012 |
| n/a | Fairburn | 40 | 40 | ORRI1Q / ORRI1R | Connected | 2009 |
| n/a | Fallago | 144 | 144 | FALL10 | Connected | 2012 |
| n/a | Farr | 92 | 92 | FAAR1Q / FAAR1R | Connected | 2005 |
| n/a | Galawhistle | 0 | 66.7 | COAL10 | 2017 | n/a |
| n/a | Glenmorie | 0 | 114 | SHIN10 | 2017 | n/a |
| n/a | Glens of Foundland Wind | 26 | 26 | KEIT10 / KINT10 | Connected | 2005 |
| n/a | Gordonbush Wind | 70 | 70 | GORW20 | Connected | 2012 |
| n/a | Gordonstown Hill | 12.5 | 12.5 | KINT10 | Connected | 2011 |
| n/a | Greenwire | 0 | 2000 | PEMB40 | 2017 | n/a |
| n/a | Greenwire 2 | 0 | 1000 | PENT40 | 2018 | n/a |
| n/a | Griffin | 204 | 204 | GRIF1S / GRIF1T | 2013 | n/a |
| n/a | Hadyard Hill | 117 | 117 | HADH10 | Connected | 2005 |
| n/a | Halsary | 0 | 41.4 | MYBS1Q / MYBS1R | 2016 | n/a |
| n/a | Harestanes | 163.3 | 163.3 | HARE10 | 2013 | n/a |
| n/a | Harrows Law | 42.5 | 42.5 | HALA10 | 2013 | n/a |
| n/a | HearthStanes B | 0 | 81 | HEAR10 | 2016 | n/a |
| n/a | Hill of Fishrie | 12.5 | 12.5 | STRI1Q / STRI1R | 2014 | n/a |
| n/a | Hill of Towie | 48.3 | 48.3 | KEIT10 / MACD1Q | Connected | 2011 |
| n/a | Houstry Wind | 13.5 | 13.5 | DUBE1Q | Connected | 2004 |
| n/a | Invercassley | 50 | 50 | LAIR1Q | 2014 | n/a |
| n/a | Kilbraur | 67 | 67 | STRB20 | Connected | 2007 - 2009 |
| n/a | Kildrummy | 18.4 | 18.4 | TARL1Q / TARL1R | Connected | 2011 |
| n/a | Kilgallioch | 0 | 274 | GLLU1Q / GLLU1R | 2017 | n/a |
| n/a | Kingsburn | 20 | 20 | BONN10 | Connected | 2011 |
| n/a | Achany | 50 | 50 | LAIR1Q | Connected | 2009 |
| n/a | Loch Luichart | 51 | 51 | MOSS1Q / MOSS1R | 2013 | n/a |
| n/a | Loch Urr | 0 | 84 | GLLU1Q / GLLU1R | 2018 | n/a |
| n/a | Longpark | 38 | 38 | GALA10 | Connected | 2009 |
| n/a | Margree | 42.5 | 42.5 | MARG10 | 2013 | n/a |
| n/a | Mark Hill | 56 | 56 | MAHI20 | Connected | 2010 |
| n/a | Mid Hill Wind | 75 | 75 | MIDH10 | 2013 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Millenium Wind | 65 | 65 | MILW1Q | Connected | 2007 - 2009 |
| n/a | Minsca | 37.5 | 37.5 | CHAP10 | Connected | 2007 |
| n/a | Moorhouse | 47.5 | 47.5 | WHIL20 | 2014 | n/a |
| n/a | Nant-Y-Moch | 0 | 176 | TRAW40 | 2017 | n/a |
| n/a | Neilston | 80 | 80 | NEIW10 | Connected | 2012 |
| n/a | Newfield | 60 | 60 | NEWF1Q | Connected | 2012 |
| n/a | North Nesting Wind | 0 | 250 | BLHI40 | 2016 | n/a |
| n/a | Novar | 18.5 | 18.5 | ALNE1Q / ALNE1R | Connected | 1997 |
| n/a | Novar 2 | 32 | 32 | ALNE1Q / ALNE1R | Connected | 2011 |
| n/a | Pairc Wind | 0 | 94 | BEAU40 | 2015 | n/a |
| n/a | Paul's Hill Wind | 70 | 70 | GLFA10 | Connected | 2005 |
| n/a | Pencloe | 63 | 63 | BLAC10 | Connected | 2012 |
| n/a | Pentland Road | 0 | 18 | ARMO10 | 2015 | n/a |
| n/a | Rhigos | 0 | 299 | RHIG40 | 2016 | n/a |
| n/a | Rosehall | 25 | 25 | SHIN10 | Connected | 2012 |
| n/a | Rowantree | 67 | 67 | DUNE10 | 2014 | n/a |
| n/a | Sallachy | 0 | 66 | LAIR1Q | 2016 | n/a |
| n/a | South Muaitheabhal | 0 | 150 | ARMO10 | 2017 | n/a |
| n/a | Spittal Hill | 0 | 80 | MYBS1Q / MYBS1R | 2016 | n/a |
| n/a | Stacain | 42.5 | 42.5 | DALL20 | 2013 | n/a |
| n/a | Strathy North & South Wind | 226 | 226 | STRW10 | 2013 | n/a |
| n/a | Strathy Wood | 0 | 84 | STRW10 | 2020 | n/a |
| n/a | Stroupster | 31.5 | 31.5 | THSO1Q / THSO1R | 2014 | n/a |
| n/a | Tangy Wind | 19 | 19 | CAAD1Q / CAAD1R | Connected | 2002 |
| n/a | Tibberchindy | 0 | 40 | TARL1Q / TARL1R | 2015 | n/a |
| n/a | Toddleburn | 36 | 36 | DUNE10 | Connected | 2009 |
| n/a | Tom Nan Clach | 0 | 150 | INNE10 | 2018 | n/a |
| n/a | Tomatin | 30 | 30 | BOAG1Q | 2013 | n/a |
| n/a | Tormywheel | 32.4 | 32.4 | BAGA1Q / BAGA1R | Connected | 2012 |
| n/a | Tullo | 17 | 17 | BRID1Q / BRID1R | Connected | 2009 |
| n/a | Tullo 2 | 12.5 | 12.5 | FIDD1Q | Connected | 2012 |
| n/a | Ulzieside | 69 | 69 | GLGL1Q / GLGL1R | 2013 | n/a |
| n/a | Viking Energy | 0 | 300 | BLHI20 | 2016 | n/a |
| n/a | West Browncastle | 36 | 36 | EKIL2S | 2013 | n/a |
| n/a | Whitelee | 560 | 560 | WHIL20 | Connected | 2007 - 2009 |
| n/a | Whiteside Hill | 27 | 27 | NECU20 | Connected | 2012 |
| **Total** | | **6316.55** | **12631.15** | **Scenario Target: 16400MW Transmission Connected Target: 9289MW** | | |
| **Offshore Wind Generation** | | | | | | |
| Area | Bristol Channel | 0 | 706 | ALVE40 | 2016 | n/a |
| Area | Burbo Bank | 0 | 234 | BIRK20 | 2015 | n/a |
| Area | Docking Shoal | 0 | 500 | WALP40_EME | 2016 | n/a |
| Area | Dogger Bank | 0 | 1500 | SAEN20 / SAES20 | 2016 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| Area | Dudgeon | 0 | 500 | NORW40 | 2015 | n/a |
| Area | East Anglia | 0 | 3600 | BRFO40 / NORW40 | 2016 | n/a |
| Area | Galloper | 0 | 500 | LEIS10 | 2015 | n/a |
| Area | Greater Gabbard | 500 | 500 | LEIS10 | Connected | 2009 |
| Area | Gwynt Y Mor | 574 | 574 | GWYN40 | Connected | 2012 |
| Area | Hornsea | 500 | 1000 | GRIW40 / WALP40_EME | 2014 | n/a |
| Area | Humber Gateway | 220 | 220 | HEDO20 | 2013 | n/a |
| Area | Irish Sea | 0 | 0 | WYLF40 / STAH40 | 2017 | n/a |
| Area | Lincs | 250 | 250 | WALP40_EME | Connected | 2011 |
| Area | London Array | 630 | 907 | CLEV40 | Connected | 2011 |
| Area | Navitas Bay Wind Park | 0 | 400 | MANN40 | 2017 | n/a |
| Area | Ormonde | 150 | 150 | HEYS40 | Connected | 2011 |
| Area | Race Bank | 0 | 500 | WALP40_EME | 2015 | n/a |
| Area | Rampion | 0 | 664 | BOLN40 | 2015 | n/a |
| Area | Sheringham Shoal | 315 | 315 | NORW40 | Connected | 2010 |
| Area | Triton Knoll | 0 | 0 | GRIW40 | 2018 | n/a |
| Area | Walney 1 and 2 | 364 | 364 | STAH40 | Connected | 2010 |
| Area | Walney Ext. | 0 | 752 | STAH40 | 2016 | n/a |
| Area | West of Duddon Sands | 374 | 374 | HEYS40 | 2013 | n/a |
| Area | Westermost Rough | 205 | 205 | HEDO20 | 2014 | n/a |
| Area | Argyll Array | 0 | 0 | DALL20 | 2018 | n/a |
| Area | Beatrice | 0 | 700 | BLHI20 | 2016 | n/a |
| Area | Firth of Forth | 0 | 1075 | TORN40 / PEHE20 / BLYT4A | 2015 | n/a |
| Area | Moray Firth | 0 | 120 | PEHE20 | 2016 | n/a |
| Area | Inch Cape | 0 | 0 | TORN40 | 2017 | n/a |
| Area | Neart na Gaoithe | 450 | 450 | CRYR40 | 2014 | n/a |
| **Total** | | **4532** | **17060** | **Scenario Target: 18680MW Transmission Connected Target: 9727MW** | | |
| **Hydro Generation** | | | | | | |
| n/a | Aigas | 20 | 20 | AIGA1Q | Connected | Not Stated |
| n/a | Cashlie | 11.12 | 11.12 | KIIN10 | Connected | Not Stated |
| n/a | Ceannacroc | 20 | 20 | CEAN1Q | Connected | Not Stated |
| n/a | Clachan | 40 | 40 | CLAC1Q | Connected | Not Stated |
| n/a | Clunie | 61.2 | 61.2 | CLUN1S / CLUN1T | Connected | Not Stated |
| n/a | Culligran | 19.1 | 19.1 | CULL1Q | Connected | Not Stated |
| n/a | Deanie | 38 | 38 | DEAN1Q | Connected | Not Stated |
| n/a | Errochty | 75 | 75 | ERRO10 | Connected | Not Stated |
| n/a | Fasnakyle G1 & G3 | 46 | 46 | FASN20 | Connected | Not Stated |
| n/a | Fasnakyle G2 | 23 | 23 | FASN20 | Connected | Not Stated |
| n/a | Fasnakyle G4 | 7.5 | 7.5 | FASN20 | Connected | 2010 |
| n/a | Finlarig | 16.5 | 16.5 | FINL1Q | Connected | Not Stated |
| n/a | Glendoe | 100 | 100 | FAUG10 | Connected | Not Stated |
| n/a | Glenmoriston | 37 | 37 | GLEN1Q | Connected | Not Stated |
| n/a | Grudie Bridge | 21.7 | 21.7 | GRUB1Q / GRUB1R | Connected | Not Stated |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Inverawe | 25 | 25 | TAYN1Q / TAYN1R | Connected | Not Stated |
| n/a | Invergarry | 20 | 20 | INGA1Q | Connected | Not Stated |
| n/a | Kilmorack | 20 | 20 | KIOR1Q | Connected | Not Stated |
| n/a | Kinlochleven | 20 | 20 | KILO10 | Connected | 2001 |
| n/a | Livishie | 15 | 15 | GLEN1Q | Connected | Not Stated |
| n/a | Lochay | 47 | 47 | LOCH10 | Connected | Not Stated |
| n/a | Luichart | 34 | 34 | LUIC1Q / LUIC1R | Connected | Not Stated |
| n/a | Mossford | 18.66 | 18.66 | MOSS1Q / MOSS1R | Connected | Not Stated |
| n/a | Nant | 15 | 15 | LOCN1Q | Connected | Not Stated |
| n/a | Orrin | 18 | 18 | ORRI1Q / ORRI1R | Connected | Not Stated |
| n/a | Pitlochry | 15 | 15 | CLUN1S / CLUN1T | Connected | Not Stated |
| n/a | Quoich | 18 | 18 | QUOI10 | Connected | Not Stated |
| n/a | Rannoch | 44 | 44 | RANN1Q / RANN1R | Connected | Not Stated |
| n/a | Shin | 18.62 | 18.62 | SHIN10 | Connected | Not Stated |
| n/a | Sloy G1 & G4 | 72.5 | 72.5 | SLOY10 | Connected | Not Stated |
| n/a | Sloy G2 & G3 | 80 | 80 | SLOY10 | Connected | Not Stated |
| n/a | St Fillans | 16.8 | 16.8 | SFIL1Q | Connected | Not Stated |
| n/a | Torr Achilty | 15 | 15 | BEAU10 | Connected | Not Stated |
| n/a | Tummel | 34 | 34 | TUMB1Q / TUMB1R | Connected | Not Stated |
| n/a | Tongland | 33 | 33 | TONG10 | Connected | Not Stated |
| **Total** | | **1115.7** | **1115.7** | **Scenario Target: 1700MW<br>Transmission Connected Target: 1224MW** | | |
| **Biomass Generation** | | | | | | |
| n/a | Bristol | 0 | 0 | SEAB40 | 2013 | n/a |
| n/a | Immingham Renewable Power Station | 0 | 0 | KILL40 | 2013 | n/a |
| n/a | Port Talbot | 0 | 0 | MAGA20 | 2015 | n/a |
| n/a | Tilbury B | 1000 | 1000 | TILB20 | Connected | 2008 |
| n/a | Rothes Biopower Plant | 52 | 52 | GLRO20 | Connected | 2012 |
| n/a | Stevens Croft | 45 | 45 | CHAP10 | Connected | 2006 |
| **Total** | | **1097** | **1097** | **Scenario Target: 1520MW<br>Transmission Connected Target: 49MW** | | |
| **Marine Generation** | | | | | | |
| Wave | Cornwall | 0 | 0 | INDQ40 / LAND40 | Unknown | n/a |
| Wave | North Scotland | 0 | 889 | DOUN20 | 2015 | n/a |
| Wave | South West Wales | 0 | 0 | PEMB40 | Unknown | n/a |
| Wave | Western Scotland | 0 | 1200 | DALM2Q / DALM2R | 2017 | n/a |
| Tidal | Angelsea | 0 | 0 | WYLF40 | Unknown | n/a |
| Tidal | Between SW Scotland and Ireland | 0 | 410 | CAAD1Q / CAAD1R | 2019 | n/a |
| Tidal | Dee | 0 | 0 | DEES40 | Unknown | n/a |
| Tidal | Humber | 0 | 0 | HUMR40 | Unknown | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| Tidal | Mersey | 0 | 0 | CAPE4A | Unknown | n/a |
| Tidal | Morecambe Bay | 0 | 0 | HEYS40 | Unknown | n/a |
| Tidal | Pentland Firth | 0 | 1200 | DOUN20 | 2016 | n/a |
| Tidal | Severn | 0 | 6500 | HINP40 / SEAB40 | Unknown | n/a |
| Tidal | Solway Firth | 0 | 500 | HARK40 | Unknown | n/a |
| Tidal | South of Isle of Wight | 0 | 3000 | FAWL40 | 2017 | n/a |
| Tidal | Thames | 0 | 0 | COSO40 | Unknown | n/a |
| Tidal | Wash | 0 | 0 | SPLN40 | Unknown | n/a |
| **Total** | | **0** | **13699** | **Scenario Target: 13730MW** | | |
| **Generation from CHP** | | | | | | |
| n/a | Derwent | 218 | 218 | WILE40 | Connected | 1994 |
| n/a | Fawley | 158 | 158 | FAWL40 | Connected | 1999 |
| n/a | Grain (added) | 0 | 340 | GRAI40 | n/a | n/a |
| n/a | Immingham | 1218 | 1218 | HUMR40 | Connected | 2004 - 2008 |
| n/a | Pembroke | 0 | 490 | PEMB40 | 2016 | n/a |
| n/a | Sellafield | 155 | 155 | HUTT40 | Connected | 1993 |
| n/a | Shotton | 210 | 210 | DEES40 | Connected | 2001 |
| n/a | Teesside (added) | 0 | 905 | GRST20 | n/a | n/a |
| n/a | Stoneywood Mills | 12 | 12 | DYCE1Q / DYCE1R | Connected | Not Stated |
| n/a | BP Grangemouth | 120 | 120 | GRMO20 | Connected | Not Stated |
| n/a | Fife Energy | 123 | 123 | WFIE10 | Connected | 2000 |
| n/a | Southampton (added) | 0 | 850 | NURS40 | n/a | n/a |
| n/a | Chapelcross (added) | 0 | 240 | CHAP10 | n/a | n/a |
| n/a | Killoch (added) | 0 | 200 | COYL20 | n/a | n/a |
| **Total** | | **2214** | **5239** | **Scenario Target: 9580MW**<br>**Transmission Connected Target: 5467MW** | | |

## C.3. *Central Co-ordination – Year 2035*

Following on from Appendix C.2., Table C-5 details the options and selections made in the creation of the generation mix for year 2035 of the Central Co-ordination scenario. The selections and characteristics of hydro and biomass generation are identical to the Market Rules scenario; totalling a capacity of 1115.7MW and 1097MW respectively. Hence these plant types are not included in Table C-5. Regarding interconnector capacity, to obtain an import capacity that is near to the scenario requirement of 6810MW, the second link to the Republic of Ireland is selected on top of the interconnectors chosen for the Gone Green scenario in Table C-2.

**Table C-5 Year 2035 Generating Unit selections for the Central Co-ordination Scenario**

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| **Coal Generation** | | | | | | |
| CCS | Blyth (added) | 0 | 1600 | BLYT20 | 2020 | n/a |
| CCS | Fiddlers Ferry | 1987 | 1987 | FIDF20_SPM | Connected | 1971 - 1973 |
| CCS | Hunterston | 0 | 1650 | HUER40 | 2018 | n/a |
| IGCC CCS | Hatfield | 0 | 800 | THOM40 | 2016 | n/a |
| BL | Aberthaw | 1665 | 0 | ABTH20 | Connected | 1971 - 1979 |
| BL | Cottam | 2000 | 0 | COTT40 | Connected | 1969 - 1970 |
| BL | Ratcliffe-on-Soar | 2021 | 0 | RATS40 | Connected | 1968 - 1970 |
| M | Rugeley | 1018 | 0 | RUGE40 | Connected | 1972 |
| BL | Uskmouth | 363 | 0 | USKM20 | Connected | 2000 |
| BL | Longannet | 2284 | 0 | LOAN20 | Connected | 1973 |
| BL | Drax | 3257 | 0 | DRAX40 | Connected | 1974 - 1986 |
| BL | Teesport (added) | 0 | 0 | GRTO2A / | 2014 | n/a |
| BL | Didcot A | 0 | 0 | DIDC40 | Connected | 1973 |
| BL | Ironbridge | 0 | 0 | IRON40 | Connected | 1970 |
| BL | Kingsnorth | 0 | 0 | KINO40 | Connected | 1973 |
| M | Lynemouth | 420 | 0 | BLYT20 | Connected | 1971 |
| BL | Tilbury (added) | 0 | 0 | TILB20 | Connected | 1968 - 1972 |
| BL | Cockenzie | 0 | 0 | COCK20 | Connected | 1967 |
| BL | Eggborough | 1940 | 0 | EGGB40 | Connected | 1968 - 1969 |
| M | Ferrybridge | 1986 | 0 | FERR4A | Connected | 1966 - 1968 |
| BL | West Burton | 1987 | 0 | WBUR40 | Connected | 1967 - 1968 |
| **Total** | | **20928** | **6037** | **Scenario Target: 6000MW**<br>**Transmission Connected Target: 5990MW** | | |
| **Gas Generation** | | | | | | |
| CCS | Abernedd 1 | 0 | 470 | BAGB20 | 2015 | n/a |
| CCS | Barking C | 0 | 470 | BARK40 | 2017 | n/a |
| CCS | Carrington | 910 | 910 | CARR40 | 2014 | n/a |
| CCS | Cockenzie (added) | 0 | 1200 | COCK20 | 2035 | n/a |
| CCS | Damhead Creek 2 | 0 | 986 | KINO40 | 2016 | n/a |
| CCS | Drakelow D | 1320 | 1320 | DRAK40 | 2014 | n/a |
| CCS | Grain | 1290 | 1290 | GRAI40 | Connected | 2011 |
| CCS | Kings Lynn B | 0 | 981 | WALP40_EME | 2015 | n/a |
| CCS | Knottingley | 0 | 1500 | FERR4A | 2018 | n/a |
| CCS | Seabank | 0 | 824 | SEAB40 | 2023 | n/a |
| CCS | Spalding Ext. | 840 | 840 | SPLN40 | 2014 | n/a |
| CCS | Thames Haven | 840 | 840 | COSO40 | 2014 | n/a |
| CCS | Thorpe Marsh | 0 | 960 | THOM40 | 2016 | n/a |
| CCS | Tilbury C | 0 | 1800 | TILB40 | 2019 | n/a |
| CCS | Trafford | 0 | 1520 | CARR40 | 2018 | n/a |
| CCS | West Burton B | 1305 | 1305 | WBUR40 | Connected | 2012 |
| CCS | Wilton | 141 | 141 | GRST20 | 2014 | n/a |
| BL | Baglan Bay | 552 | 552 | BAGB20 | Connected | 2002 |
| BL | Brine Field (added) | 0 | 0 | THOR40 | 2014 | n/a |
| BL | CDCL | 395 | 395 | COTT40 | Connected | 2010 |
| BL | Coryton | 800 | 800 | COSO40 | Connected | 2000 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| BL | Damhead Creek | 805 | 805 | KINO40 | Connected | 2000 |
| BL | Enfield | 408 | 408 | BRIM2C_LPN / BRIM2D / BRIM2A_LPN / BRIM2B_LPN | Connected | 2010 |
| B M | Great Yarmouth | 420 | 420 | NORW40 | Connected | 2000 |
| BL | Langage | 905 | 905 | LANG40 | Connected | 2008 |
| BL | Little Barford | 740 | 0 | EASO40 | Connected | 1994 |
| BL | Marchwood | 900 | 900 | MAWO40 | Connected | 2008 |
| BL | Pembroke | 2100 | 2100 | PEMB40 | Connected | 2011 |
| BL | Peterhead | 1180 | 1180 | PEHE20 | Connected | 2000 |
| BL | Severn Power | 850 | 850 | USKM20 | Connected | 2010 |
| B M | Shoreham | 420 | 420 | BOLN40 | Connected | 2000 |
| BL | Spalding | 880 | 880 | SPLN40 | Connected | 2004 |
| BL | Staythorpe C | 1728 | 1728 | STAY40 | Connected | 2010 |
| M | Barking | 1000 | 0 | BARK40 | Connected | 1994 |
| BL | Barry | 245 | 0 | ABTH20 / CARE20 | Connected | 1998 |
| M | Brigg | 260 | 0 | KEAD40 | Connected | 1993 |
| BL | Connahs Quay | 1380 | 0 | DEES40 | Connected | 1996 |
| M | Corby | 407 | 0 | GREN40_EME | Connected | 1993 |
| BL | Deeside | 515 | 0 | DEES40 | Connected | 1994 |
| BL | Didcot B | 1550 | 0 | DIDC40 | Connected | 1996 |
| BL | Keadby | 735 | 0 | KEAD40 | Connected | 1994 |
| M | Killingholme 1 | 900 | 0 | KILL40 | Connected | 1992 |
| M | Killingholme 2 | 665 | 0 | KILL40 | Connected | 1993 |
| BL | Kings Lynn A | 340 | 0 | WALP40_EME | Connected | 1996 |
| BL | Medway | 700 | 0 | GRAI40 | Connected | 1995 |
| M | Peterborough | 405 | 0 | WALP40_EME | Connected | 1993 |
| BL | Rocksavage | 810 | 0 | ROCK40 | Connected | 1997 |
| M | Roosecote | 229 | 0 | HUTT40 | Connected | 1991 |
| M | Rye House | 715 | 0 | RYEH40 | Connected | 1993 |
| BL | Seabank | 1234 | 0 | SEAB40 | Connected | 1998 - 2000 |
| BL | South Humberbank | 1285 | 0 | SHBA40 | Connected | 1996 |
| M | Teesside | 45 | 0 | GRST20 | Connected | 1992 |
| B M | Saltend | 1100 | 1100 | SAES20 | Connected | 1999 |
| B M | Sutton Bridge | 819 | 819 | WALP40_EME | Connected | 1998 |
| OCGT | Barking (added) | 0 | 320 | BARK20_LPN | n/a | n/a |
| OCGT | Cowes | 145 | 0 | FAWL40 | Connected | 1982 |
| OCGT | Didcot A | 0 | 0 | DIDC40 | Connected | 1968 - 1970 |
| OCGT | Indian Queens | 140 | 0 | INDQ40 | Connected | 1996 |
| OCGT | Taylors Lane | 144 | 0 | WISD20_LPN | Connected | 1979 - 1981 |
| **Total** | | **35497** | **31939** | **Scenario Target: 33000MW Transmission Connected Target: 31941MW** | | |
| **Nuclear Generation** | | | | | | |
| EPR | Bradwell B | 0 | 1670 | RAYL40 | 2021 | n/a |
| EPR | Dungeness C | 0 | 1650 | DUNG40 | 2018 | n/a |
| EPR | Hinkley Point C 1 | 0 | 0 | HINP40 | 2017 | n/a |
| EPR | Hinkley Point C 2 | 0 | 0 | HINP40 | 2018 | n/a |
| EPR | Moorside 1 | 0 | 0 | SELL40 | 2023 | n/a |
| EPR | Moorside 2 | 0 | 0 | SELL40 | 2025 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| EPR | Oldbury C | 0 | 0 | OLDS10 | 2023 | n/a |
| EPR | Oldbury-on-Severn Power Station | 0 | 1600 | OLDS10 | 2020 | n/a |
| EPR | Sizewell C 1 | 0 | 1670 | SIZE40 | 2020 | n/a |
| EPR | Sizewell C 2 | 0 | 1670 | SIZE40 | 2021 | n/a |
| APR | Sizewell B | 1212 | 1212 | SIZE40 | Connected | 1994 |
| APR | Wylfa C 1 | 0 | 1200 | WYLF40 | 2020 | n/a |
| APR | Wylfa C 2 | 0 | 0 | WYLF40 | 2021 | n/a |
| APR | Wylfa C 3 | 0 | 0 | WYLF40 | 2022 | n/a |
| AGR | Dungeness B | 1081 | 1081 | DUNG40 | Connected | 1985 - 1989 |
| AGR | Hartlepool | 1207 | 1207 | HATL20 | Connected | 1989 |
| AGR | Heysham | 2406 | 2406 | HEYS40 | Connected | 1989 |
| AGR | Hinkley Point B | 1261 | 1261 | HINP40 | Connected | 1976 - 1978 |
| AGR | Hunterston | 1074 | 1074 | HUER40 | Connected | 1964 |
| AGR | Torness | 1215 | 1215 | TORN40 | Connected | 1988 |
| MX | Oldbury | 0 | 0 | OLDS10 | Connected | 1967 - 1968 |
| MX | Wylfa | 0 | 0 | WYLF40 | Connected | 1971 |
| **Total** | | **9456** | **22256** | **Scenario Target: 22080MW** | | |
| **Onshore Wind Generation** | | | | | | |
| n/a | Achruach | 49.9 | 49.9 | ACHR1Q / ACHR1R | 2014 | n/a |
| n/a | Afton | 68 | 68 | BLAC10 | 2014 | n/a |
| n/a | Aikengall | 48 | 48 | DUNB1Q / DUNB1R | Connected | 2009 |
| n/a | Aikengall 2 | 108 | 108 | DUNB1Q / DUNB1R | 2014 | n/a |
| n/a | Allt Duine | 0 | 87 | BOAG1Q / BOAG1R | 2016 | n/a |
| n/a | An Suidhe | 20.7 | 20.7 | ANSU10 | Connected | 2010 |
| n/a | Andershaw | 45 | 45 | ANDE10 | Connected | 2012 |
| n/a | Ardkinglas | 19.25 | 19.25 | ARDK10 | Connected | 2008 |
| n/a | Arecleoch | 120 | 120 | AREC10 | Connected | 2010 |
| n/a | Auchencorth | 45 | 45 | KAIM20 | Connected | 2010 |
| n/a | Aultmore | 60 | 60 | AULW1S | 2014 | n/a |
| n/a | Baillie & Bardnaheigh Wind | 52.5 | 52.5 | DOUN10 | Connected | 2012 |
| n/a | Beinn an Turic | 30 | 30 | CAAD1Q / CAAD1R | Connected | 2001 |
| n/a | Beinn an Turic 2 | 43.7 | 43.7 | CAAD1Q / CAAD1R | Connected | 2010 |
| n/a | Beinn Tharsuinn | 29 | 29 | ALNE1Q / ALNE1R | Connected | 2004 |
| n/a | Ben Aketil Wind | 28 | 28 | DUGR1Q | Connected | 2007 |
| n/a | Benbrack and Quantans Hill | 0 | 0 | COYT1T | 2018 | n/a |
| n/a | Berry Burn | 72.5 | 72.5 | BLHI20 | 2013 | n/a |
| n/a | Black Craig | 40 | 40 | BLCR10 | 2013 | n/a |
| n/a | Black Law | 121 | 121 | BLLA10 | Connected | 2005 |
| n/a | Black Law Ext. | 69 | 69 | BLKX10 | 2013 | n/a |
| n/a | Blackcraig | 71.3 | 71.3 | BLCW10 | 2013 | n/a |
| n/a | Bowbeat | 33 | 33 | KAIM20 | Connected | 2010 |
| n/a | Boyndie Wind | 14.3 | 14.3 | KEIT10 / MACD1Q | Connected | 2005 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Braes of Doune | 74 | 74 | BRAC21 / BRAC22 | Connected | 2004 |
| n/a | Broadmeadows | 18 | 18 | GALA10 | Connected | 2012 |
| n/a | Brockloch Rig | 75 | 75 | DUNH1S / DUNH1T | 2014 | n/a |
| n/a | Burn of Whilk | 22.5 | 22.5 | MYBS1Q / MYBS1R | 2013 | n/a |
| n/a | Cairn Uish | 50.6 | 50.6 | DAAS20 | Connected | 2004 |
| n/a | Cairn Uish 2 | 41.4 | 41.4 | DAAS20 | 2013 | n/a |
| n/a | Calliachar | 62.1 | 62.1 | CALW20 | 2014 | n/a |
| n/a | Camster | 62.5 | 62.5 | MYBS1Q / MYBS1R | Connected | 2012 |
| n/a | Carnedd Wen | 0 | 150 | TRAW40 | 2016 | n/a |
| n/a | Carraig Gheal | 46 | 46 | FERO10 | Connected | 2012 |
| n/a | Carscreugh | 21.25 | 21.25 | GLLU1Q / GLLU1R | 2013 | n/a |
| n/a | Causeymire | 55.2 | 55.2 | MYBS1Q / MYBS1R | Connected | 2004 |
| n/a | Clashindarroch | 166.7 | 166.7 | CLAS20 | 2014 | n/a |
| n/a | Clyde | 521 | 521 | CLYN2Q / CLYS2R | Connected | 2010 |
| n/a | Coire Na Cloiche | 0 | 30 | ALNE1Q / ALNE1R | 2016 | n/a |
| n/a | Corriegarth | 49.9 | 49.9 | FOYE20 | 2014 | n/a |
| n/a | Corriemollie | 0 | 47.5 | BEAU10 | 2015 | n/a |
| n/a | Cour | 0 | 23 | CAAD1Q / CAAD1R | 2015 | n/a |
| n/a | Cruach Mhor | 29.75 | 29.75 | DUNO1Q / DUNO1R | Connected | 2004 |
| n/a | Crystal Rig 1 | 62.5 | 62.5 | DUNB1Q / DUNB1R | Connected | 2003 |
| n/a | Crystal Rig 2 | 200 | 200 | CRYR40 | Connected | 2009 |
| n/a | Dalswinton | 30 | 30 | DUMF10 | Connected | 2008 |
| n/a | Dersalloch | 69 | 69 | DESA1Q | 2013 | n/a |
| n/a | Deucheran Hill | 15 | 15 | CAAD1Q / CAAD1R | Connected | 2001 |
| n/a | Dorenell | 0 | 0 | KEIT10 | 2019 | n/a |
| n/a | Drumderg | 36.8 | 36.8 | COUA10 | Connected | 2007 |
| n/a | Dummuies | 12.3 | 12.3 | KEIT10 | Connected | 2010 |
| n/a | Dumnaglass | 0 | 0 | BEAU40 | 2018 | n/a |
| n/a | Dun Law | 30 | 30 | DUNE10 | Connected | 2010 |
| n/a | Dunbeath | 55 | 55 | KINT10 | 2014 | n/a |
| n/a | Earlsburn | 35 | 35 | BONN10 | Connected | 2006 |
| n/a | Earlshaugh | 0 | 108 | EHAU10 | 2015 | n/a |
| n/a | Edinbane Wind | 41.4 | 41.4 | EDIN10 | Connected | 2008 |
| n/a | Eishken Estate | 0 | 150 | BEAU40 | 2015 | n/a |
| n/a | Erica | 21.6 | 21.6 | BEAU10 | 2014 | n/a |
| n/a | Ewe Hill | 66 | 66 | EWEH1Q | Connected | 2012 |
| n/a | Fairburn | 40 | 40 | ORRI1Q / ORRI1R | Connected | 2009 |
| n/a | Fallago | 144 | 144 | FALL10 | Connected | 2012 |
| n/a | Farr | 92 | 92 | FAAR1Q / FAAR1R | Connected | 2005 |
| n/a | Galawhistle | 0 | 66.7 | COAL10 | 2017 | n/a |
| n/a | Glenmorie | 0 | 114 | SHIN10 | 2017 | n/a |
| n/a | Glens of Foundland Wind | 26 | 26 | KEIT10 / KINT10 | Connected | 2005 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Gordonbush Wind | 70 | 70 | GORW20 | Connected | 2012 |
| n/a | Gordonstown Hill | 12.5 | 12.5 | KINT10 | Connected | 2011 |
| n/a | Greenwire | 0 | 2000 | PEMB40 | 2017 | n/a |
| n/a | Greenwire 2 | 0 | 1000 | PENT40 | 2018 | n/a |
| n/a | Griffin | 204 | 204 | GRIF1S / GRIF1T | 2013 | n/a |
| n/a | Hadyard Hill | 117 | 117 | HADH10 | Connected | 2005 |
| n/a | Halsary | 0 | 41.4 | MYBS1Q / MYBS1R | 2016 | n/a |
| n/a | Harestanes | 163.3 | 163.3 | HARE10 | 2013 | n/a |
| n/a | Harrows Law | 42.5 | 42.5 | HALA10 | 2013 | n/a |
| n/a | HearthStanes B | 0 | 81 | HEAR10 | 2016 | n/a |
| n/a | Hill of Fishrie | 12.5 | 12.5 | STRI1Q / STRI1R | 2014 | n/a |
| n/a | Hill of Towie | 48.3 | 48.3 | KEIT10 / MACD1Q | Connected | 2011 |
| n/a | Houstry Wind | 13.5 | 13.5 | DUBE1Q | Connected | 2004 |
| n/a | Invercassley | 50 | 50 | LAIR1Q | 2014 | n/a |
| n/a | Kilbraur | 67 | 67 | STRB20 | Connected | 2007 - 2009 |
| n/a | Kildrummy | 18.4 | 18.4 | TARL1Q / TARL1R | Connected | 2011 |
| n/a | Kilgallioch | 0 | 274 | GLLU1Q / GLLU1R | 2017 | n/a |
| n/a | Kingsburn | 20 | 20 | BONN10 | Connected | 2011 |
| n/a | Kyle | 0 | 300 | KYLN10 | Connected | 2011 |
| n/a | Achany | 50 | 50 | LAIR1Q | Connected | 2009 |
| n/a | Loch Luichart | 51 | 51 | MOSS1Q / MOSS1R | 2013 | n/a |
| n/a | Loch Urr | 0 | 0 | GLLU1Q / GLLU1R | 2018 | n/a |
| n/a | Longpark | 38 | 38 | GALA10 | Connected | 2009 |
| n/a | Margree | 42.5 | 42.5 | MARG10 | 2013 | n/a |
| n/a | Mark Hill | 56 | 56 | MAHI20 | Connected | 2010 |
| n/a | Mid Hill Wind | 75 | 75 | MIDH10 | 2013 | n/a |
| n/a | Millenium Wind | 65 | 65 | MILW1Q | Connected | 2007 - 2009 |
| n/a | Minsca | 37.5 | 37.5 | CHAP10 | Connected | 2007 |
| n/a | Moorhouse | 47.5 | 47.5 | WHIL20 | 2014 | n/a |
| n/a | Nant-Y-Moch | 0 | 176 | TRAW40 | 2017 | n/a |
| n/a | Neilston | 80 | 80 | NEIW10 | Connected | 2012 |
| n/a | Newfield | 60 | 60 | NEWF1Q | Connected | 2012 |
| n/a | North Nesting Wind | 0 | 250 | BLHI40 | 2016 | n/a |
| n/a | Novar | 18.5 | 18.5 | ALNE1Q / ALNE1R | Connected | 1997 |
| n/a | Novar 2 | 32 | 32 | ALNE1Q / ALNE1R | Connected | 2011 |
| n/a | Pairc Wind | 0 | 94 | BEAU40 | 2015 | n/a |
| n/a | Paul's Hill Wind | 70 | 70 | GLFA10 | Connected | 2005 |
| n/a | Pencloe | 63 | 63 | BLAC10 | Connected | 2012 |
| n/a | Pentland Road | 0 | 18 | ARMO10 | 2015 | n/a |
| n/a | Rhigos | 0 | 299 | RHIG40 | 2016 | n/a |
| n/a | Rosehall | 25 | 25 | SHIN10 | Connected | 2012 |
| n/a | Rowantree | 67 | 67 | DUNE10 | 2014 | n/a |
| n/a | Sallachy | 0 | 66 | LAIR1Q | 2016 | n/a |
| n/a | South Muaitheabhal | 0 | 150 | ARMO10 | 2017 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Spittal Hill | 0 | 80 | MYBS1Q / MYBS1R | 2016 | n/a |
| n/a | Stacain | 42.5 | 42.5 | DALL20 | 2013 | n/a |
| n/a | Strathy North & South Wind | 226 | 226 | STRW10 | 2013 | n/a |
| n/a | Strathy Wood | 0 | 0 | STRW10 | 2020 | n/a |
| n/a | Stroupster | 31.5 | 31.5 | THSO1Q / THSO1R | 2014 | n/a |
| n/a | Tangy Wind | 19 | 19 | CAAD1Q / CAAD1R | Connected | 2002 |
| n/a | Tibberchindy | 0 | 40 | TARL1Q / TARL1R | 2015 | n/a |
| n/a | Toddleburn | 36 | 36 | DUNE10 | Connected | 2009 |
| n/a | Tom Nan Clach | 0 | 0 | INNE10 | 2018 | n/a |
| n/a | Tomatin | 30 | 30 | BOAG1Q | 2013 | n/a |
| n/a | Tormywheel | 32.4 | 32.4 | BAGA1Q / BAGA1R | Connected | 2012 |
| n/a | Tullo | 17 | 17 | BRID1Q / BRID1R | Connected | 2009 |
| n/a | Tullo 2 | 12.5 | 12.5 | FIDD1Q | Connected | 2012 |
| n/a | Ulzieside | 69 | 69 | GLGL1Q / GLGL1R | 2013 | n/a |
| n/a | Viking Energy | 0 | 300 | BLHI20 | 2016 | n/a |
| n/a | Waterhead Moor | 0 | 72 | WAMR10 | 2014 | n/a |
| n/a | West Browncastle | 36 | 36 | EKIL2S | 2013 | n/a |
| n/a | Whitelee | 560 | 560 | WHIL20 | Connected | 2007 - 2009 |
| n/a | Whiteside Hill | 27 | 27 | NECU20 | Connected | 2012 |
| **Total** | | **6316.55** | **11962.15** | **Scenario Target: 15370MW Transmission Connected Target: 8706MW** | | |
| **Offshore Wind Generation** | | | | | | |
| Area | Bristol Channel | 0 | 302 | ALVE40 | 2016 | n/a |
| Area | Burbo Bank | 0 | 234 | BIRK20 | 2015 | n/a |
| Area | Docking Shoal | 0 | 500 | WALP40_EME | 2016 | n/a |
| Area | Dogger Bank | 0 | 500 | SAEN20 / SAES20 | 2016 | n/a |
| Area | Dudgeon | 0 | 500 | NORW40 | 2015 | n/a |
| Area | East Anglia | 0 | 900 | BRFO40 / NORW40 | 2016 | n/a |
| Area | Galloper | 0 | 500 | LEIS10 | 2015 | n/a |
| Area | Greater Gabbard | 500 | 500 | LEIS10 | Connected | 2009 |
| Area | Gwynt Y Mor | 574 | 574 | GWYN40 | Connected | 2012 |
| Area | Hornsea | 500 | 1000 | GRIW40 / WALP40_EME | 2014 | n/a |
| Area | Humber Gateway | 220 | 220 | HEDO20 | 2013 | n/a |
| Area | Irish Sea | 0 | 0 | WYLF40 / STAH40 | 2017 | n/a |
| Area | Lincs | 250 | 250 | WALP40_EME | Connected | 2011 |
| Area | London Array | 630 | 907 | CLEV40 | Connected | 2011 |
| Area | Navitas Bay Wind Park | 0 | 0 | MANN40 | 2017 | n/a |
| Area | Ormonde | 150 | 150 | HEYS40 | Connected | 2011 |
| Area | Race Bank | 0 | 500 | WALP40_EME | 2015 | n/a |
| Area | Rampion | 0 | 332 | BOLN40 | 2015 | n/a |
| Area | Sheringham Shoal | 315 | 315 | NORW40 | Connected | 2010 |
| Area | Triton Knoll | 0 | 0 | GRIW40 | 2018 | n/a |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| Area | Walney 1 and 2 | 364 | 364 | STAH40 | Connected | 2010 |
| Area | Walney Ext. | 0 | 392 | STAH40 | 2016 | n/a |
| Area | West of Duddon Sands | 374 | 374 | HEYS40 | 2013 | n/a |
| Area | Westermost Rough | 205 | 205 | HEDO20 | 2014 | n/a |
| Area | Argyll Array | 0 | 0 | DALL20 | 2018 | n/a |
| Area | Beatrice | 0 | 400 | BLHI20 | 2016 | n/a |
| Area | Firth of Forth | 0 | 1075 | TORN40 / PEHE20 / BLYT4A | 2015 | n/a |
| Area | Moray Firth | 0 | 0 | PEHE20 | 2016 | n/a |
| Area | Inch Cape | 0 | 0 | TORN40 | 2017 | n/a |
| Area | Neart na Gaoithe | 450 | 450 | CRYR40 | 2014 | n/a |
| **Total** | | **4532** | **11444** | **Scenario Target: 12610MW Transmission Connected Target: 6566MW** | | |
| **Marine Generation** | | | | | | |
| Wave | Cornwall | 0 | 0 | INDQ40 / LAND40 | Unknown | n/a |
| Wave | North Scotland | 0 | 889 | DOUN20 | 2015 | n/a |
| Wave | South West Wales | 0 | 0 | PEMB40 | Unknown | n/a |
| Wave | Western Scotland | 0 | 1200 | DALM2Q / DALM2R | 2017 | n/a |
| Tidal | Angelsea | 0 | 0 | WYLF40 | Unknown | n/a |
| Tidal | Between SW Scotland and Ireland | 0 | 410 | CAAD1Q / CAAD1R | 2019 | n/a |
| Tidal | Dee | 0 | 0 | DEES40 | Unknown | n/a |
| Tidal | Humber | 0 | 0 | HUMR40 | Unknown | n/a |
| Tidal | Mersey | 0 | 0 | CAPE4A | Unknown | n/a |
| Tidal | Morecambe Bay | 0 | 0 | HEYS40 | Unknown | n/a |
| Tidal | Pentland Firth | 0 | 332 | DOUN20 | 2016 | n/a |
| Tidal | Severn | 0 | 6500 | HINP40 / SEAB40 | Unknown | n/a |
| Tidal | Solway Firth | 0 | 0 | HARK40 | Unknown | n/a |
| Tidal | South of Isle of Wight | 0 | 1700 | FAWL40 | 2017 | n/a |
| Tidal | Thames | 0 | 0 | COSO40 | Unknown | n/a |
| Tidal | Wash | 0 | 0 | SPLN40 | Unknown | n/a |
| **Total** | | **0** | **11031** | **Scenario Target: 11000MW** | | |
| **Generation from CHP** | | | | | | |
| n/a | Derwent | 218 | 218 | WILE40 | Connected | 1994 |
| n/a | Fawley | 158 | 158 | FAWL40 | Connected | 1999 |
| n/a | Grain (added) | 0 | 340 | GRAI40 | n/a | n/a |
| n/a | Immingham | 1218 | 1218 | HUMR40 | Connected | 2004 - 2008 |
| n/a | Pembroke | 0 | 490 | PEMB40 | 2016 | n/a |
| n/a | Sellafield | 155 | 155 | HUTT40 | Connected | 1993 |
| n/a | Shotton | 210 | 210 | DEES40 | Connected | 2001 |
| n/a | Teesside (added) | 0 | 905 | GRST20 | n/a | n/a |
| n/a | Stoneywood Mills | 12 | 12 | DYCE1Q / DYCE1R | Connected | Not Stated |
| n/a | BP Grangemouth | 120 | 120 | GRMO20 | Connected | Not Stated |
| n/a | Fife Energy | 123 | 123 | WFIE10 | Connected | 2000 |

| Plant Type | Power Station | Base Case Capacity (MW) | Scenario Capacity (MW) | Node(s) Name | Connection Date | Commission Date |
|---|---|---|---|---|---|---|
| n/a | Southampton (added) | 0 | 850 | NURS40 | n/a | n/a |
| n/a | Chapelcross (added) | 0 | 240 | CHAP10 | n/a | n/a |
| n/a | Killoch (added) | 0 | 0 | COYL20 | n/a | n/a |
| **Total** | | **2214** | **5039** | **Scenario Target: 9390MW<br>Transmission Connected Target: 5359MW** | | |

## C.4. *References for Appendix C*


[C.1] National Grid. "*National Electricity Transmission System Seven Year Statement*", Appendix F, May 2011

[C.2] National Grid. "*Electricity Ten Year Statement*", Appendix F, November 2012

[C.3] Energy UK. "*The Energy Bill and potential implications for smaller generators and suppliers"*, April 2013