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Multi-objective transmission reinforcement planning approach for analysing future energy scenarios in the Great Britain network

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Abstract: A multi-objective transmission reinforcement planning framework has been designed to evaluate the effect of applying a future energy scenario to the Great Britain transmission network. This is achieved by examining the identified non-dominated set of transmission reinforcement plans, which alleviate thermal capacity constraints, for the multi-criteria problem of five objectives: investment cost, annual constraint cost saving, annual incremental operation and maintenance cost, outage cost and annual line loss saving. The framework is flexible and utilises a systematic algorithm to generate reinforcement plans and alter the associated reinforcements should they exacerbate thermal constraints; hence a pre-determined set of reinforcements is not required to evaluate a scenario. The reinforcements considered are line addition (single circuit and double circuit) and line upgrading through reconductoring. The Strength Pareto Evolutionary Algorithm 2 is utilised to explore varying locations, configurations and capacities of network reinforcement. The solutions produced achieve similar cost savings to solutions created by the transmission network owners, showing the suitability of the approach to provide a useful trade-off analysis of the objectives and to assess the network-related thermal and economic impact of future energy scenarios. Here, the framework is applied to the 2020 generation mix of the Gone Green scenario developed by National Grid.

1 Introduction

When evaluating energy scenarios for the United Kingdom (UK), designed to achieve governmental emission reduction targets, the most prominent research projects (LENS 2050 [1], Department of Energy and Climate Change 2050 [2] and UK Energy Research Centre's Energy 2050 project [3]) either made significant simplifications in assessing the electrical network reinforcement requirement, and associated costs, of a scenario [2] or did not consider them [1, 3]. However in evaluating Gone Green, a scenario developed by National Grid (NG), a detailed study by the Great Britain (GB) transmission network owners (TNOs) was involved to evaluate potential reinforcement solutions for the GB transmission network to accommodate the scenario in 2020 [4]. The reinforcements were designed to adhere to rules defined by the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS). A cost benefit analysis (CBA) was used to select the best performing reinforcement solutions using the following formulation

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

where C_{TR} is the 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.

Due to the linear relationship used, the trade-offs between each cost were not assessed. Exploring objective trade-offs can aid the network planner in defining positive and negative effects which result from investing more or less into the network. In light of this and previous work relating to scenario evaluation [1–3], a multi-objective transmission reinforcement planning (MOTREP) framework has been designed to explore these trade-offs and evaluate the economic and thermal impact of a future energy scenario to the GB transmission network.

The MOTREP framework evaluates a scenario through generating transmission reinforcement plans (TRPs), which adhere to current thermal rules defined by the NETS SQSS [5], to alleviate discovered thermal constraints. The evaluation is carried out by locating a non-dominated set of TRPs for the multi-criteria problem of investment cost, outage cost, annual network constraint cost saving, annual line loss saving and the added objective of annual incremental operation and maintenance (O&M) cost, associated with the extra O&M requirement of an added line. TRPs generated from multi-criteria analysis, due to the unweighted nature of the objectives, encompass reinforcement possibilities for different planning goals, which may not have been previously considered. Hence, multi-criteria analysis can therefore be used to improve the evaluation of a scenarios impact to the network.

The MOTREP framework utilises a systematic planning algorithm to generate reinforcement plans and 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. A drawback of previous transmission expansion planning (TEP) models, as originally identified in [6], is the exclusion in the planning algorithm of the ability to redesign and rearrange the reinforcements applied. This process is important to ensure that the original TRP is given the opportunity to exceed, however, minimal necessary alterations need to be made, to help maintain the initial characteristics of the plan. Previous TEP models, as originally identified in [6], often do not consider other options of reinforcement/expansion beyond generic line addition ([7–9]), particularly cheaper alternatives such as line upgrading. To generate TRPs, the modelling approach proposed considers the options, at the same voltage level, of reconductoring the existing line (single circuit or double circuit) and line addition (single circuit and/or double circuit). With the inclusion of line reconductoring, the ability to redesign reinforcements is crucial when no line additions have been

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applied, and the thermal capacity of the upgrade is no longer acceptable for the new power flow, following the application of the TRP. Overall, the methods employed in the framework are designed to enhance the multi-objective assessment and improve scenario evaluation.

The MOTREP framework combines the systematic planning algorithm with a state-of-the-art multi-objective evolutionary algorithm (MOEA), to enable the exploration on a practical multi-voltage network, of varying locations, configurations and capacity limits of transmission reinforcement. Candidate circuits are created for the scenario – enabling the framework to easily evaluate a multitude of generation mixes – for each reinforcement plan as opposed to having a set of generic candidate circuits, for all plans, as an input [7–9]. Further, the framework includes a stochastic, dynamic and seasonal evaluation of the annual network constraint cost saving of a TRP. Multi-objective TEP models, when including an objective related to network congestion, often simply assess the associated effect of a reinforcement/expansion plan at peak demand [10], or across several time steps around peak demand [9]. However, as each plan is usually designed for peak demand conditions, this gives an overly positive outlook on the associated impact. Further, in reality, high levels of network congestion can occur at low demand levels during the summer season due to the planned outages of transmission lines. The method employed includes planned summer outages of network assets; however, the improved evaluation greatly increases the simulation time of the framework. To limit computational demands, a DC power flow-based model of the GB network is used.

The MOEA chosen is the Strength Pareto Evolutionary Algorithm 2 (SPEA2) [11]. The SPEA2 outperforms the original SPEA [11] and yields promising results in comparison to other techniques such as the Non-dominated Sorting Genetic Algorithm II [10]. The original SPEA has been adapted successfully for application to the TEP problem [12], however, here the SPEA2 method is used to include the improvements made over the original SPEA.

This paper details the design of the MOTREP framework and its application to the Gone Green scenario in 2020. TRP solutions generated by the framework are analysed and compared with solutions from the TNOs study [4] to verify the robustness of the approach for evaluating future UK energy scenarios.

2 Setting scenario generating unit outputs

To create the scenario generation mix, the transmission entry capacity (TEC), location, connection date and commissioning date (all obtained from Appendix B in [13]) of each generating unit and interconnector, currently connected/expected to connect to the GB network, is required. The scenario is created by adding or removing generating units/interconnectors that have, respectively, a near term predicted connection date or a commissioning date that brings the unit/interconnectors continued operation into question for the future scenario year.

To adhere to thermal rules outlined in the current NETS SQSS [5], thermal loadings of any line should not exceed the pre-fault capacity rating, under the condition that generating unit outputs are set to those that arise from the economy planned transfer condition (EPTC). Before application of the EPTC, generating units deemed to contribute to scenario peak demand are identified using the scenario plant margin. In calculating the plant margin, network demand includes the addition/removal of interconnector export/import contributions (determined using the method in [14]) to specified network nodes. If the plant margin exceeds 20%, then a case study-based generator-type ranking order is used to remove the smallest contributory generating unit of the lowest ranking type until a 20% (or lower) plant margin is achieved.

The power output of the contributory generating units is then set using the EPTC (Appendix E of [5]), which involves directly scaling down specified generating unit types, using availability parameters set by a CBA carried out by the NETS SQSS working group, before then scaling down the remaining units using a scaling factor, such that total generation matches demand (including interconnector import/export contributions). Note: for power flow simulations, network nodal demand is calculated from scenario peak demand by maintaining the demand distribution of the case study base case network.

3 Systematic approach to generating reinforcement plans for the initial population

An initial population of TRPs that are full of variety and good-quality solutions is crucial to reducing the simulation time of the multi-criteria optimisation. The SPEA2 explores a pre-defined solution search space in order to improve the initial population objective evaluations through an iterative process of evolution, until a final non-dominated solution set is obtained. Fig. 1 shows the method employed for initial population creation. A plans' annual constraint cost saving (CC_{SAV}) (see Section 4 for details) is used to determine the solutions inclusion in the initial population. If a plans' CC_{SAV} is greater than zero then it is included in the population, else, the plan is excluded; this ensures an initial population of good-quality solutions. As a consequence of recent changes in grid access for the UK system, through the 'Connect and Manage' regime – which has allowed NG to offer earlier grid access to new and existing generation projects [15], network congestion is a principal driver of future reinforcement. Hence, a minimum requirement of a TRP should be to achieve a saving in annual constraint costs. The MOTREP framework uses Matpower to carry out DC power flow (DCPF) and DC optimal power flow (DCOPF) calculations [16].

To create the search space, a maximum power flow condition, PFC_{MAX}, is selected for each population individual between user-defined limits; chosen in this case as 84 and 42%. The maximum power flow condition is a constraint, which the TRP must satisfy, on the maximum power flow (as a percentage of line capacity) across any line in the combined network (base case network and TRP) under peak demand. The 84% limit, which is the most onerous power flow condition, is determined from a study carried out by the authors on the 2009 GB network at peak demand, which found that the largest power flow on a line was 84% of the capacity (in this case the post-fault continuous capacity rating). Hence by varying PFC_{MAX}, a TRP is created for scenario peak demand that either increases network surplus capacity (to cater for added generation after the scenario year), or maintains surplus capacity. Fig. 2 details the number of thermal limit violations in excess of PFC_{MAX}, that result in the base case network (2014/2015 GB transmission network in this case) from varying levels of PFC_{MAX}, for the Gone Green scenario in 2020. The TRPs, for the case study in this paper, will therefore contain reinforcements at between a minimum of 50 and 210 locations. A PFC_{MAX} of 42% was therefore deemed a suitable lower limit to create the search space. Reinforcements are therefore not often solely applied to lines where thermal capacity is a pressing issue and the search space is broadened to include potentially helpful solutions for the multi-objective problem.

Thermal limit violations (in excess of PFC_{MAX}) are identified following the setting of generating unit outputs using the EPTC. For each violation, three options of reinforcement are generated: line reconductoring and single-circuit/double-circuit line addition. The capacity of these options is obtained by the formulation below

$$MVA_{UPG}|MVA_{ADD} = DCPF_{LINE}/(PFC_{LINE}/100) \quad (2)$$

where

$$PFC_{LINE}^{Min} \leq PFC_{LINE} \leq PFC_{LINE}^{Max} \quad (3)$$

$$MVA_{ORIG} < MVA_{UPG} \leq MVA_{VOLT} \quad (4)$$

$$MVA_{ADD} \leq MVA_{VOLT} \quad (5)$$

and, MVA_{UPG}/MVA_{ADD} is the mega-volt ampere (MVA) line

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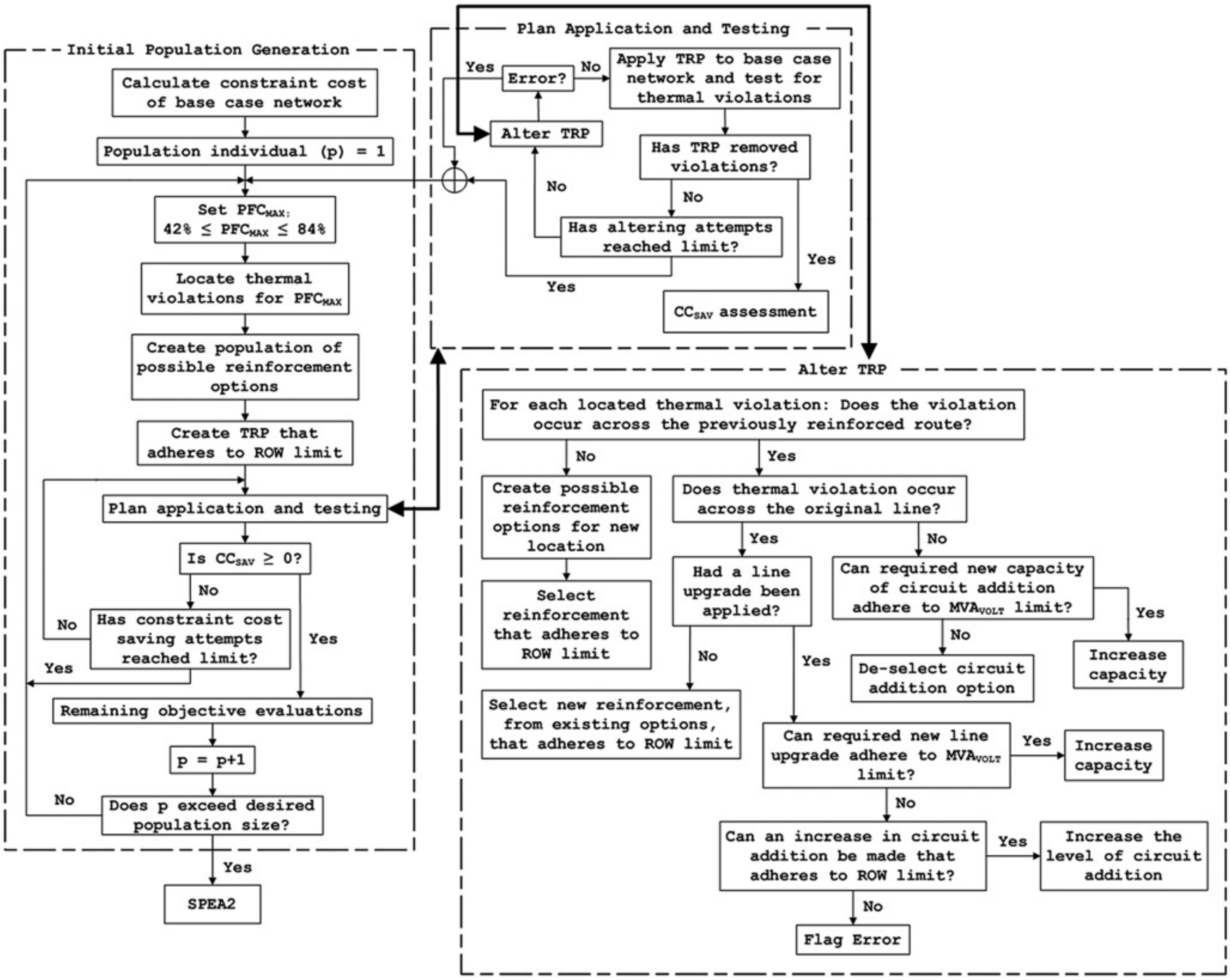

Fig. 1 *Flowchart of the systematic method employed to generate reinforcement plans for the initial population*

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

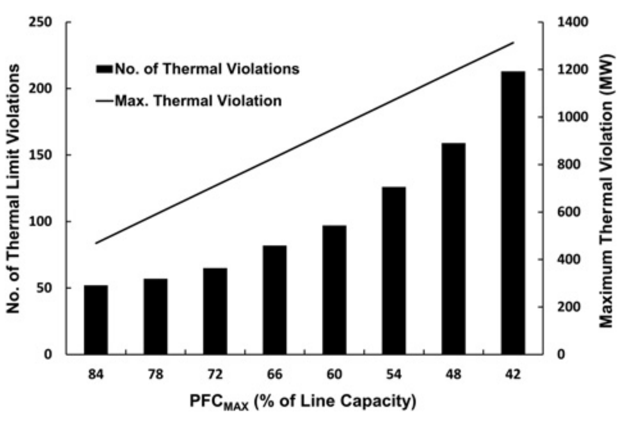

Fig. 2 *Number of thermal limit violations observed (in excess of PFC_{MAX}) and the maximum MW thermal violation observed (above PFC_{MAX}) for the Gone Green scenario (year 2020) under varying levels of PFC_{MAX}*

The maximum line ratings of each voltage level in the base case network are used for MVA_{VOLT}. For PFC_{LINE}^{Min} and PFC_{LINE}^{Max} the values of 20 and 84% were chosen. A pre-defined number of attempts at locating a satisfactory line capacity are allowed, to alleviate the thermal violation discovered from the chosen PFC_{MAX} of the TRP, and satisfy the constraints of (5)–(7). On locating a satisfactory line capacity, per unit (p.u.) resistance and reactance values are updated for the new line capacity level using suitable normalised per-km resistance and reactance p.u. values obtained from the line capacities in the base case network.

Following the generation of reinforcement options, TRPs are created by selecting combinations that adhere to the right-of-way (ROW) constraint

$$0 \le N_{ij} \le N_{ij}^{Max} \tag{6}$$

where N_{ij} and N_{ij}^{Max}, respectively, represent the number of circuits, and the maximum number of circuits which can be added, along the network route *i–j*. Here, based on the quantity of circuits found to connect along the same route at certain locations of the GB network, a ROW constraint of four is used.

After creating the TRP, the method for plan application and testing (shown in Fig. 1) is used. The plan is applied to the base case network and tested for thermal violations in excess of the minimum condition for surplus network capacity; the most onerous power flow condition. If no violations exist, the plans' CC_{SAV} is evaluated, and if a saving is calculated, the plan is evaluated against the remaining objectives. If, however, violations

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are discovered then the plan is modified using the 'alter TRP' process. The iterative process allows for a number of attempts at altering the plan and finding a successful TRP that eliminates thermal violations (above the most onerous power flow condition), thereby giving the initial TRP the opportunity to succeed. If the process is stopped, either due to the pre-defined number of attempts for locating a satisfactory TRP being reached or an error being flagged, a new PFC_{MAX} is selected for the population individual and a new TRP is generated; the previous attempt is removed. Note: the process for determining a new reinforcement capacity follows the procedure as formulated in (2).

4 Objective evaluations

4.1 Investment cost

The TRP investment cost can be formulated as

$$\text{IC}_{\text{TRP}} = \sum_{k \in \text{TRP}} \left(C_{ijk}^{\text{SC}} \text{SC}_{ijk} + C_{ijk}^{\text{DC}} \text{DC}_{ijk} + C_{ijk}^{\text{UPG}} \text{UPG}_{ijk} \right) \quad (7)$$

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

4.2 Annual line loss saving and O&M cost

The line loss saving objective evaluates the saved I^2R resistive heating losses as a result of the TRP. As the framework uses a DCPF to model the GB transmission network [17], the annual line loss saving of a network is simply calculated using the formulation from [4]

$$\text{LL}_{\text{SAV}}^{\text{YEAR}} = \left[5000 \times \left(\text{LL}_{\text{SAV}}^{\text{PK-NEW}} - \text{LL}_{\text{SAV}}^{\text{PK-ORIG}}\right)\right] + 2.3 \quad (8)$$

where the terawatt (TW) line loss of a network at scenario peak demand is calculated as follows

$$\text{LL}_{\text{SAV}}^{\text{PK}} = \sum_{k} \left(P_{ijk}^2 R_{ijk} \right) \times S_{\text{base}} \quad (9)$$

and, $\text{LL}_{\text{SAV}}^{\text{YEAR}}$ is the annual TWh line loss saved; $\text{LL}_{\text{SAV}}^{\text{PK-NEW}}$ and $\text{LL}_{\text{SAV}}^{\text{PK-ORIG}}$ represent the TW line loss at scenario peak demand of the new network (including the TRP) and the base case network respectively; P_{ijk} is the p.u. active power flowing in the kth transmission line from i–j; R_{ijk} is the p.u. resistance of the kth transmission line from i–j; and S_{base} is the system MVA base. Equation (8) is a straight line estimation of the recent trend (across several years), on the GB network, between line losses at peak demand and across the year.

Under this formulation, 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. However, the effect of line addition increases the annual incremental O&M cost of a TRP, OM_{TRP}. This is the cost associated with maintenance on newly added underground cables (UGCs) and overhead lines (OHLs) (i.e. the cost of added route patrols, inspections, vegetation management and tower painting), and is assessed using £/circuit-km coefficients on each TRP line addition.

4.3 Outage cost

Costs associated with planned outages, which usually occur in the summer, result from compensation payments made by the network operator 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. These compensation payments refund the transmission network use of system (TNUoS) charges paid by the affected generating units for the outage duration [18]. The planned outage cost of a TRP, required to accommodate construction, is calculated by splitting the TRP into outage groups. An outage group is a group of lines in the TRP that are to be excluded from the base case network at the same time. Currently, the desired number of outage groups is created by splitting the TRP equally. The number of outage groups that can be assessed depends on the computational effort required for assessing the annual constraint cost saving of a plan. Further, reducing the number of groups too far can cause electrical islanding of the base case network.

Total generating unit dispatch, per week outage cost and outage duration are assessed for each outage group sequentially using a DCOPF, following the calculation of nodal demand, from the case study-based summer minimum demand value (i.e. the median demand value for the base case network year and the scenario year), the identification of contributory generating units (using the method in Section 2), and the determination of expected generating unit outputs using the security planned transfer condition (Appendix C of [5]); which excludes the economy criterion of the EPTC. Each outage group assessment involves excluding the associated lines from the base case network, running the DCOPF, reinstating the lines and including the group reinforcements to the network; thereby including the effect on generating unit dispatch of a previous group's network reinforcement. The outage cost TRP assessment can be formulated as follows

$$\text{OC}_{\text{TRP}} = \sum_{i} \left(\text{OC}_{\text{WK}i} \times \text{OD}_i \right) \quad (10)$$

where

$$\text{OC}_{\text{WK}i} = \sum_{j} \left(\text{Gen}_{\text{DP}j} \times \text{TNUoS}_{\text{WK}j} \right) \quad (11)$$

and, OC_{TRP} is the total outage cost of the TRP; $\text{OC}_{\text{WK}i}$ and OD_i is the outage cost per week and the outage duration for the ith outage group, respectively; $\text{Gen}_{\text{DP}j}$ is the total MW dispatch of the jth generating unit following an outage of the lines associated with the ith outage group; and $\text{TNUoS}_{\text{WK}j}$ is the equivalent per week zonal TNUoS charge to be refunded to the jth generating unit.

In calculating outage duration, it is assumed that line upgrading can be achieved at a rate of 3.9 circuit-km/week (calculated from [4]) and 0.15 circuit-km/week (calculated from [19]) for OHL and UGC sections, respectively, and that line addition requires an outage of only 1 week (due to the assumption that work involving line addition can be carried out adjacent to the existing line). A number of simplifications to assess the total TRP outage cost needed to be made to reduce computational effort. For example, annual zonal TNUoS tariffs are assumed to remain constant for the case study; recalculating tariffs for new generation expansion plans and demand levels, as detailed in [20], is outside the scope of this paper.

4.4 Annual constraint cost saving

The annual constraint cost of a TRP is assessed using a method similar to [21]. However, the method used here includes cost optimisation; hence, the minimum constraint cost combination of offers/bids is selected when constraining generating units on/off. Generator offer/bid prices are part of the balancing mechanism (BM) under which a system operator will pay a generator unit an offer price to increase its output, or receive a bid price payment from the unit to reduce its output.

To calculate the constraint cost of a network, load duration curves (LDC) for winter and summer, updated for the scenario year, are used. A summer outage season is included in this objective assessment, to account for planned outages that regularly occur during the lowest demand period of the summer season. The

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summer outage LDC is obtained from the last section of the summer LDC. The length of a typical UK summer outage season is around 8 weeks. The summer season LDC was therefore reduced to 23 weeks for the case study. For the outage season, eight of the most onerous outages to the base case network were accounted for and excluded (to match [21]).

Each seasonal LDC is split into eight demand blocks, of varying duration, using the rectangular rule to capture its shape. The resulting levels of demand are used along with stochastic generator unit output assumptions to dynamically assess annual congestion levels for the scenario year, and the annual cost resulting from operation of the BM. 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.

For each simulation (in each demand block) if supply exceeds demand then, using a generator-type ranking order, the output of the smallest unit of the lowest ranked generator type is set to zero until generation matches demand by altering the output of the next to be removed unit. A piecewise linear cost curve is then derived for each generating unit, by allocating no cost for the initial unit output and applying a cost, equal to the unit offer price, to the remaining unused TEC. The DCOPF must therefore calculate the forced dispatch/optimal re-dispatch of generation, due to thermal constraints, to reduce the system operator's outlay in the BM. The assessment of the annual constraint cost saving of a TRP can be formulated as follows

$$\mathrm{CC_{SAV}} = \mathrm{CC_{ORIG}} - \mathrm{CC_{NEW}} \tag{12}$$

where

$$\mathrm{CC_{NEW}}|\mathrm{CC_{ORIG}} = \mathrm{CC_W} + \mathrm{CC_S} + \mathrm{CC_{SO}} \tag{13}$$

$$\mathrm{CC_{W|S|SO}} = \sum_{i=1}^{\lim}\sum_{g=1}^{G}\left\{\left[\left(\mathrm{COn}_g \times \mathrm{OP}_g\right) - \left(\mathrm{COf}_g \times \mathrm{BP}_g\right)\right] \times S_{\mathrm{DUR}}\right\} \tag{14}$$

and, $\mathrm{CC_{SAV}}$ is the annual network constraint cost saving of the TRP; $\mathrm{CC_{ORIG}}$ and $\mathrm{CC_{NEW}}$ are the annual constraint costs of the original and new network (including the TRP), respectively; $\mathrm{CC_W}$, $\mathrm{CC_S}$ and $\mathrm{CC_{SO}}$ are the network constraint costs for the winter, summer and summer outage seasons, respectively; COn_g and COf_g are the constrained on/off MW variations in output for generator unit g; G is the total number of contributory generating units for the simulation; OP_g and BP_g are the offer and bid price for generator unit g; S_{DUR} is the duration (in hours) that the simulation represents; and lim is the limit of simulations set for the season.

5 Adapted SPEA2 method

Following the creation of the initial population (P_t) of TRPs, the adapted SPEA2 procedure with archive size N, and maximum generation limit T is carried out as shown in Fig. 3. The SPEA2 is an improvement to the SPEA due to the use of an enhanced fitness assignment procedure, the use of a truncation operator and the use of only non-dominated solutions in A_{t+1} for mating selection and population variation [11]. The uniform method for crossover is used here to improve exploration of the search space [22]. Both the crossover and mutation operators include the plan application and testing process, detailed in Fig. 1, to ensure that after each step in the variation procedure, each population individual can still adhere to the minimum condition of surplus network capacity (i.e. the most onerous power flow condition).

The crossover operator generates new TRPs by swapping transmission reinforcement solutions, with matching network routes, between TRPs in the mating pool (limited by a defined probability). The adaptive mutation operator occurs after crossover and mutates the new TRP reinforcement solutions by altering the selections made for the network route (ensuring adherence to the ROW constraint) and altering the reinforcement options using the procedure as formulated in (2). The probability of mutation is gradually incremented, for this adaptive operator design, if the resulting TRP fails to cause a saving in $\mathrm{CC_{SAV}}$ after a pre-defined number of mutation attempts.

6 Security testing

Each TRP in the non-dominated set is tested against thermal security criteria outlined in the current NETS SQSS [5]. The criterion is that at peak demand, there shall not be thermal overloading of any transmission equipment in the event of the fault outage of a single transmission circuit (N-1), a double-circuit OHL (N-D, excluding those located in Scottish Power Transmission's system at a voltage level of 132 kV), or a single transmission circuit with the prior outage of another transmission circuit (N-2) where both circuits are located in NG's transmission system.

As the computational effort to carry out a full N-1 security assessment on a TRP (combined with the base case network) is significant, the security test is carried out after locating the non-dominated solutions. Each non-dominated TRP is tested against every N-1 outage, every applicable N-D outage and finally every applicable but critical N-2 outage combination. If a thermal overload is located in any of the three security tests, then the TRP is removed from the set. Experience shows that this rarely occurs in practice when each TRP is designed to adhere at a minimum to a $\mathrm{PFC_{MAX}}$ of 84%.

7 Case study

The chosen case study is the Gone Green scenario created in 2011 [23]. Table 1 details the modelled transmission connected generation mix of the scenario for the year 2020. The base case network used is the year 2014/2015 GB network (network data can be found at [24]) which has been chosen to match the TNOs' analysis [4]. This network consists of 911 network nodes and 1091 transmission lines, 22,688 km of which are OHLs and 975 km are UGCs. The values used for $\mathrm{MVA_{VOLT}}$ are 500, 1910 and 3820 MVA for voltage levels of 132, 275 and 400 kV, respectively.

For calculating $\mathrm{OC_{TRP}}$, annual zonal TNUoS tariffs from 2012/2013 [25] are used, summer minimum demand is assumed to be 22.54 GW, and due to the time period from the base case network to the scenario year, ten outage groups were used; two outage groups per year. For calculating $\mathrm{CC_{SAV}}$, the type of probability distribution, availability and the parameters used for each generator type (obtained from [21]) to generate the stochastic output assumptions for supply is detailed in Table 2. The output from wind (both onshore and offshore) is obtained using a triangular distribution, with a minimum and maximum limit of 5 and 80%, respectively – a mean output of 35 and 40% for onshore and offshore wind results in a distribution mode of 20 and 35%, respectively. The bid/offer prices used to represent the BM are obtained from [4] and the number of simulations is 40, 44 and 16 for the winter, summer and summer outage seasons, respectively.

To calculate $\mathrm{IC_{TRP}}$, the cost coefficients in Table 3 (calculated from [26, 27]) are used. For upgrading of OHLs, there was a distinct trend found in [27] between distance and cost for the £/MVA-km cost coefficient. Hence, an upgrade adjustment factor (see Table 3) is used to adjust the OHL upgrade coefficients for the required reinforcement route length. To calculate $\mathrm{OM_{TRP}}$, coefficients of £767 and £2398/circuit-km are used (calculated from [28]) for all new OHLs and UGCs, respectively. To identify contributory generating units, the generator-type ranking order detailed in Table 4 (based on Table 7.1 in [14]) is used.

8 Case study output

The framework multi-objective results for the Gone Green scenario are detailed in Fig. 4; no TRPs were found to fail the security test.

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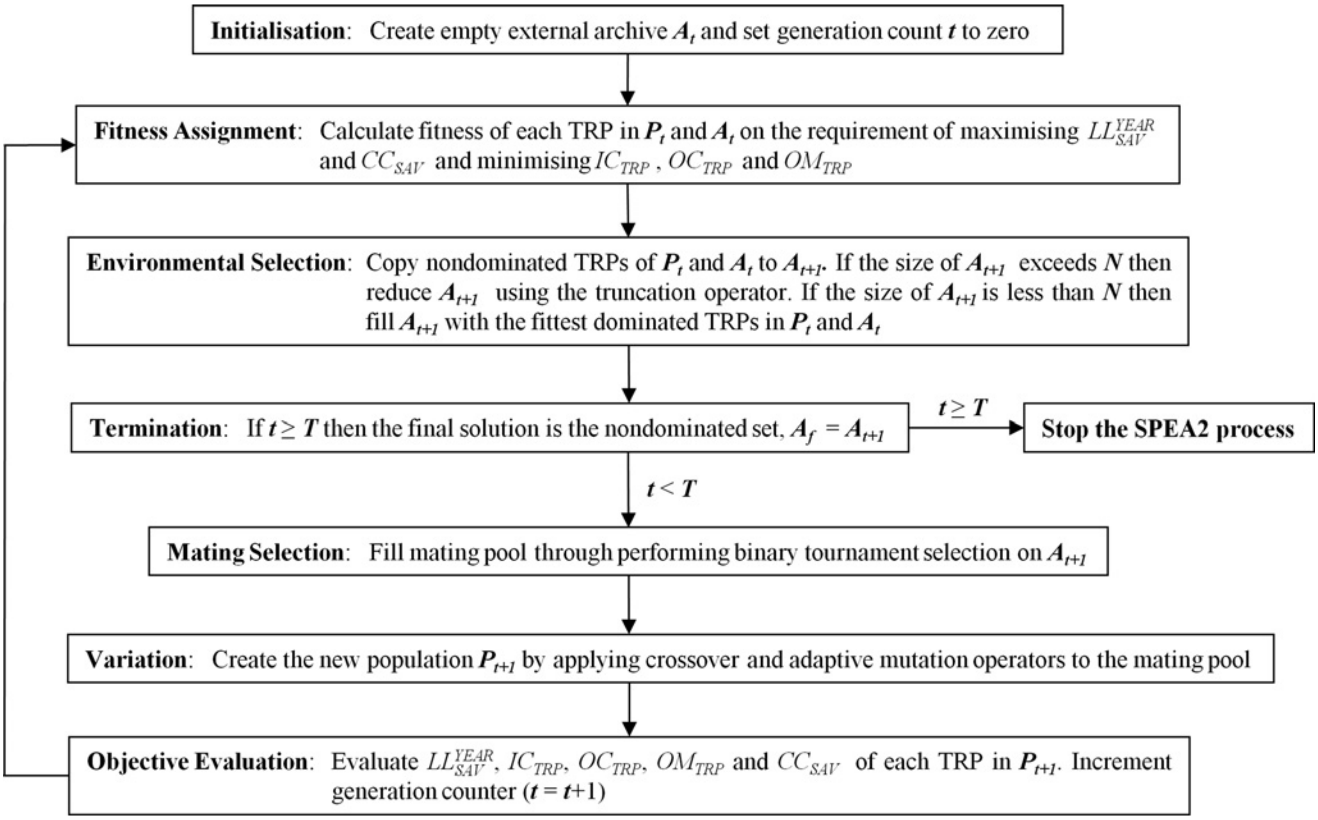

Fig. 3 *Flowchart of the adapted SPEA2 procedure*

From Fig. 4*a* it is clear that by increasing network investment cost from £1.28 to £7.51 billion, annual line loss saving can be reduced by 3.62 TWh; equating to a saving of £216.95 million (using £60/MWh, a conservative cost of future energy [4]). Annual incremental O&M cost of a TRP is found to conflict with this trend in Fig. 4*b* and increase with greater network investment from £1.03 to £7.22 million (see also Fig. 4*c*), as does the trend for outage cost in Fig. 4*d* which generally increases from £198.47 million to £1.66 billion; though the trend in Fig. 4*d* is convex in nature, in comparison to the linear trend in Fig. 4*b* and quadratic trend in Fig. 4*a*. With each additional £1 million expenditure on the onshore network, from an initial outlay of £1.28 billion, a further upfront cost of £235 k for network outages could therefore be required and an increased annual cost saving of only £34 k (reduced slightly to take into account the minimal increase in OM_{TRP}) from reducing line losses could be achieved. This annual cost saving is too low to justify further network expansion. However, annual savings that can result from reducing constraint costs are more significant.

Table 1 Gone Green scenario generation mix for the year 2020

Generation type	Year 2011/2012, GW	Year 2020, GW
coal	28.80	14.55
gas	29.60	35.51
nuclear	10.41	12.32
combined heat and power (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
peak demand	58.6	59

As can be seen in Figs. 4*g* and *j*, the trade-offs involving annual constraint cost saving are less clear. This is due to the reality of the complex conflict between constraint cost and investment cost that exists. The approach creates and utilises a wide range of reinforcement solutions, resulting in solutions that either alleviate network congestion across the whole year or across part of the year, but exacerbate congestion during (for example) the summer outage season. The TRPs are able to achieve an annual constraint cost saving of between £186,600 (0.02%) and £848.41 million (94%) from the original £903.84 million constraint cost assessment of the base case network in 2020.

Although clear trade-offs involving CC_{SAV} cannot be defined for this case study, top performing non-dominated TRPs can be located for the multi-objective problem, and a verdict can be reached on the

Table 2 Generator-type probability distributions, availabilities and parameters

Generation type	Distribution	Winter mean, %	Summer mean, %	Other parameters
wind (onshore; offshore)	triangular	35; 40	35; 40	Min 5%; Max 80%
nuclear	binomial	80	70	n/a
wave; tidal	binomial	30; 35	30; 35	n/a
base load combined gas cycle turbine (CCGT) (±CCS)	binomial	90	85	n/a
base load coal (±CCS)	binomial	85	75	n/a
hydro (high demand; low demand)	normal	60; 10	60; 5	σ of 4%
marginal gas	binomial	90	85	n/a
marginal coal	binomial	85	75	n/a
CHP	binomial	83	78	n/a
biomass	binomial	80	75	n/a
pumped storage (high demand; low demand)	binomial	90; 25	90; 15	n/a

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Table 3 Circuit-type cost coefficients

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	£5.9 million/km
UGC double-circuit addition	£7.2 million/km
OHL upgrade adjustment factor	−£0.28/km

Table 4 Generator-type ranking order

Generator type	Ranking order	Generator type	Ranking order
CHP	1	wave	8
base CCGT	2	tidal	9
onshore wind	3	base coal	10
nuclear	4	marginal CCGT	11
hydro	5	marginal coal	12
biomass	6	pumped storage	13
offshore wind	7	open cycle gas turbine	14

economic impact, from the perspective of the transmission network, of the Gone Green energy scenario. Several methods, specific to the users' demands, could be used to evaluate a scenario from the frameworks output. Here, an estimation of payback time is used which is 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 base case network; formulated as follows

$$\mathrm{PB} = \frac{\mathrm{IC_{TRP}} + \mathrm{OC_{TRP}} + \sum_{n=1}^{N}\left(\frac{\mathrm{OM_{TRP}}}{N} \times n\right)}{\mathrm{CC_{SAV}} + \mathrm{LL_{SAV}^{COST}} - \mathrm{OM_{TRP}}} \quad (15)$$

where PB is the payback period in years; $\mathrm{LL_{SAV}^{COST}}$ is the cost associated with $\mathrm{LL_{SAV}^{YEAR}}$ (using £60/MWh); 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 trend in $\mathrm{OM_{TRP}}$ is assumed during the period of TRP construction.

The top ten TRPs with the lowest payback period are detailed in Table 5. All ten solutions have a payback period of <3 years which highlights the significant economic saving that can be made from investing in the GB network under this scenario. The best solutions, on the whole, consist of line upgrades (UPG) as the significant component and often largest single component compared with single-circuit additions (SCA) or double-circuit additions (DCA). Many of the solutions require a large number of reinforcements to the onshore network, particularly over 5 years. This may seem unrealistic, however, some reinforcements can be installed post scenario year and the reinforcement route lengths are low; a total route length of 1209.76 km exists for the majority of the best solutions. From Table 5 it is clear that the most significant reinforcements are required in zones 7, 9 and 13; an expectation due to the increased penetration of onshore wind generation in Scotland for the Gone Green scenario (8.4 GW assumed), required to meet continued high electrical demand in the south.

The TNOs' analysis [4] relates to the original Gone Green scenario from 2008 and adheres to NETS SQSS rules from that year. However, comparisons between their analysis and this study can still be made as their analysis includes scenario variants of the 2008 scenario. Further, costing assumptions and methods used for their CBA still hold true at the time of writing. The reinforcements in [4] range from a solution that excludes the addition of new circuits (i.e. using line upgrades and series compensators) costing an estimated £625 million (£465 million excluding series compensators), to a solution that includes the same line upgrades as well as two offshore DC cables of around 350 km (running down either side of the UK), costing an estimated £2.077 billion overall (£1.917 billion excluding series compensators).

In [4], for a scenario variant which involved 11.4 GW of onshore wind capacity (situated in Scotland), the constraint cost of the base case network in 2020 was estimated to be £1,013.3 million (in comparison to £903.84 million calculated here) and savings of between £371.9 and £823.2 million could be achieved using the various reinforcement solutions. It is clear from Fig. 4 and Table 5 that the MOTREP framework solutions can achieve similar levels of constraint cost saving for similar levels of investment cost. For

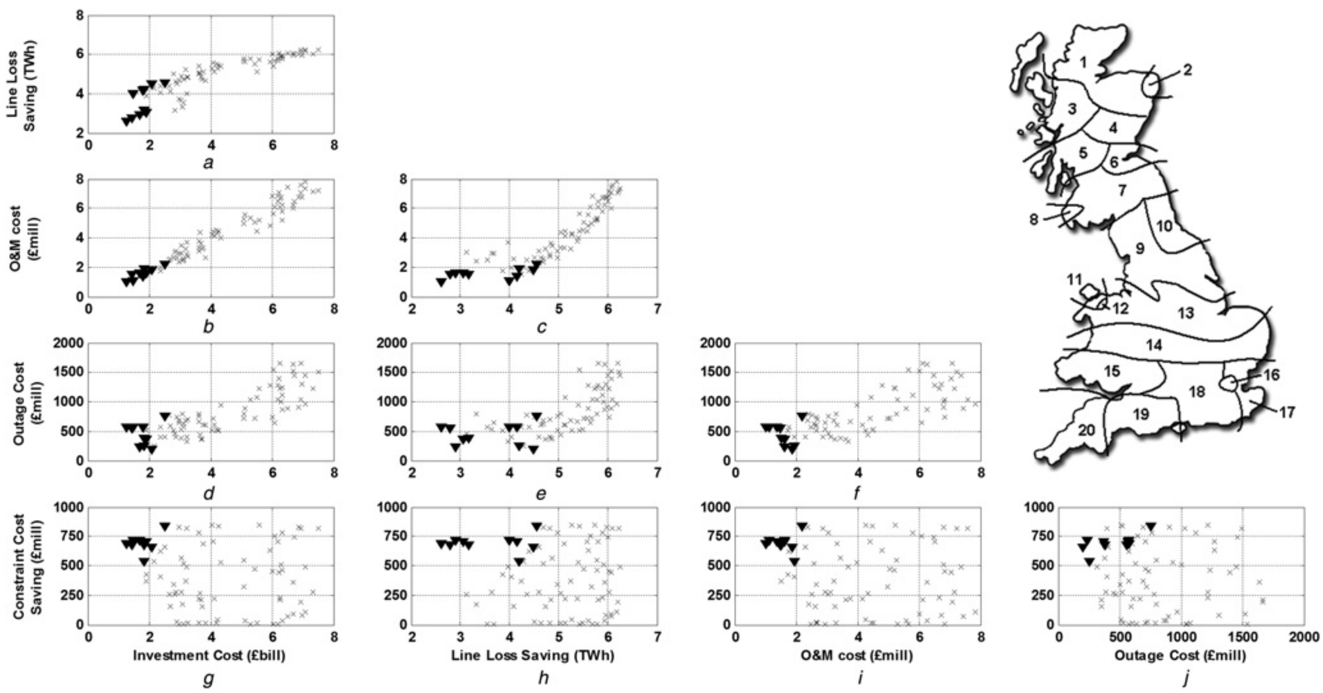

Fig. 4 *MOTREP framework non-dominated multi-objective results (plot a – j) with zonal split inset figure of the GB transmission network. SPEA2 results, using a crossover and mutation rate of 0.9 and 0.4, respectively, were obtained after 200 generations for an initial population size of 120 and an archive size of 80. Top ten TRPs according to payback period are detailed in Table 5 and marked with triangles in the figure*

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Table 5 Top ten TRPs according to payback period

TRP ID	No. of double-circuits/ single-circuits/upgrades	Total OHL/UGC route length to be reinforced, km	Max reinforcement capacity (MVA; type; Zone)	IC_{TRP}, £ bill	CC_{SAV}, £ mill	OC_{TRP}, £ mill	O&M cost, £ mill	LL_{SAV}^{YEAR}, TWh	PB, years
1	28/22/36	1126.9/110.26	3670; UPG; 9	1.50	715.00	572.95	1.11	4.00	2.17
2	21/26/36	1099.5/110.26	2942; UPG; 9	1.28	691.41	572.11	1.03	2.60	2.19
3	28/32/35	1099.5/110.26	3465; UPG; 13	1.70	711.11	232.95	1.63	2.90	2.20
4	30/31/32	1099.5/110.26	3496; UPG; 7	1.46	673.64	559.59	1.50	2.78	2.41
5	34/34/30	1191.9/110.10	3554; SCA; 13	2.07	656.13	198.47	1.86	4.48	2.47
6	26/30/37	1126.9/110.26	3717; UPG; 9	1.79	707.92	563.32	1.38	4.16	2.47
7	28/34/35	1099.5/110.26	3601; UPG; 7	1.92	709.67	372.84	1.62	3.05	2.58
8	29/26/38	1099.5/110.26	3373; UPG; 13	1.85	675.28	375.80	1.50	3.17	2.59
9	38/33/36	1206.8/110.33	3681; DCA; 9	1.85	535.26	253.84	1.94	4.20	2.68
10	39/48/70	2368.7/120.95	3487; UPG; 7	2.54	835.58	751.11	2.18	4.56	2.97

the two solutions outlined above (i.e. upgrade only and upgrades plus high voltage direct current cables), it is estimated in [4] that they will require an outage cost of £117 and £121 million, respectively, for installation and achieve an annual line loss saving of 0.3 and 1.1 TWh. The framework solutions require higher levels of outage cost for installation due to the onshore location of the reinforcements; however, the resulting annual line loss savings are greater, for the same reasons, offsetting the associated outage cost and maintaining roughly the same ratio between outage cost and annual line loss saving as in [4].

In comparison, it is clear that the MOTREP framework can generate reinforcement solutions that have a similar impact on the transmission planning objectives analysed as the solutions produced by the GB TNOs. Hence, the proposed approach can be deemed to assess reliably the thermal and economic impact of a future energy scenario to the GB transmission network. This is despite the onshore location of the reinforcement solutions in comparison to the offshore location of some of the TNO solutions. The differences in the solutions generated are due to simplifications in the model design that have had to be made to improve computational efficiency. These simplifications include the use of a DC power flow-based model of the GB network, excluding the voltage constraints associated with an AC power flow-based model, and the exclusion of reinforcement options such as the installation of offshore cables and flexible AC transmission system devices. However, it is as a result of these simplifications that the framework employed is able to be realistically used for analysing multiple scenarios. Multiple scenarios need to be evaluated to aid government energy policy in defining the best scenario for the UK 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 transmission system can be quickly identified.

9 Conclusions

A new framework has been proposed to evaluate the thermal and economic impact of future energy scenarios to the GB transmission network. The framework utilises a systematic algorithm to create reinforcement solutions (including the option of line upgrading) for a multi-voltage network and alter the associated reinforcements should they exacerbate thermal constraints, resulting in a wide range of TRPs to perform a more comprehensive multi-objective analysis. The proposed approach can thus be applied to any scenario without the need of a set of pre-determined network reinforcements; an advantage for scenario evaluation. The MOTREP framework has been applied to the Gone Green scenario for the year 2020, and through utilising a measure of payback period it can be concluded, from the solutions generated, that a minimum investment cost of £1.50 billion is required for the onshore GB transmission network to optimally accommodate the scenario.

The economic impact of the top performing TRP solutions from the Gone Green case study have been compared with solutions produced by the GB TNOs. The apparent similarity between the impacts of either set of solutions on the objectives analysed demonstrates the suitability of the framework for assessing future energy scenarios. Although planning criteria trade-offs involving annual constraint cost saving remain unclear for the scenario studied, the trade-offs of the remaining crucial planning objectives in the analysis are evident. Hence, the proposed approach can still be utilised to support the decision making process behind scenario-related transmission reinforcement planning of the GB network. However, this study does raise the question of whether the SPEA2 (or another MOEA) is able to define trade-offs related to annual network congestion, when the search space of reinforcement options is expanded, and an improved evaluation of annual network constraints is included, to better simulate the planning problem.

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