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Incorporating Line Security Constraints within Network Planning for Dynamic Line Rating Systems

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Abstract— In order to maintain system security levels against a backdrop of generation and demand growth, network planners may require grid expansion and/or line modification measures. Traditionally, this has been achieved by uprating existing lines and constructing new lines. However, technical, environmental, cost and timeliness concerns can encourage the adoption of dynamic line rating (DLR) systems, as part of enhancing the utilisation of the existing network. Hence, a novel approach is presented here for planning reconductoring and DLR systems, relating to the implementation of security constraints. A multi-year stochastic mixed integer linear model for line N-1 short time security is developed, incorporating a unit commitment stage, which is later solved using Benders decomposition. An additional pre-optimisation stage, which can be efficiently parallelised, is introduced to largely support the burden of incorporating the security constraints. In addition, staged investments for individual lines, including applying DLR before later reconductoring, is investigated. The effectiveness of the proposed approach is shown for the IEEE RTS 24 bus system.

Keywords— *Dynamic line rating, Congestion management, Security constraints, Benders decomposition, Network planning*

I. INTRODUCTION

The increasing trend of wind farm buildout across many systems, along with electrical demand growth, has become a challenge for the expansion of transmission and distribution systems, as wind-rich regions are often located in remote or weak sections of the network. Concurrently meeting network security requirements further challenges this complex process. Constructing new lines is a traditional solution, but obtaining new rights of way (ROWs) can be environmentally, socially and technically difficult. Hence, there is an increasing need to utilise existing ROWs, and existing lines, to manage network congestion, as much as possible, to integrate further renewables and adapt to load growth. Reinforcement with reconductoring, and using dynamic line rating systems (DLR), represent the most commonly favoured engineering practices.

DLR-based approaches can reveal the real-time capacity of individual lines by measuring local weather conditions, line sag or conductor tension [1], as opposed to conventional (static) line ratings based on close to worst-case scenarios. They are often seen as an attractive option for expansion planning studies, being comparatively low cost and capable of being installed relatively quickly [2]. They can also provide a cost-effective solution to address system security, specifically, as a corrective option within optimal power flow (OPF).

One convenient approach to integrate DLR with OPF is to utilise a linearised heat balance differential equation as part of the optimisation, including temperature variables [3], [4]. To solve operational problems, unit commitment, as well as linearised AC OPF, are incorporated in [3] and formulated for Benders decomposition, while an additional feasibility test ensures security. DC OPF is utilised in [4], addressing an economic dispatch case, formulating continuous operation under contingencies. This approach better suits day-ahead scheduling rather than a planning problem, which may involve a large number of scenarios. In contrast to the above, pre-calculated DLR values can be considered, according to the scenario conditions [1], [5]. Based on linearised AC OPF, a planning problem is formulated in [1], to make investment decisions relating to DLR and the construction of new lines. However, security constraints are not given here. A real-time congestion management approach is proposed in [5], which aims to minimise re-scheduling and congestion clearing time.

The presented work adopts the latter approach, which is better suited for large-scale planning problems, and focus is placed on addressing the knowledge gap for developing N-1 line emergency security constraints, for corrective security schemes, with presumed congestion clearing times. The planning horizon is assumed as 10 years, focusing on using existing ROWs before commissioning new lines. The main contributions of the paper are threefold: a MILP dual-asset model for stochastic multi-year transmission planning is developed based on DC OPF and solved using Benders decomposition, which employs both DLR and reconductoring using ACSR conductors options, and includes a simplified unit commitment model; an effective procedure is proposed to apply line emergency security constraints for DLR planning, and finally, a formulation is presented for staged investment on the same network lines. The paper is organised as follows: methodology is presented in Section II, with the formulation of the optimisation model in Section III. The RTS 24-bus test case is introduced in Section IV, with results and conclusions presented in Sections V and VI.

II. METHODOLOGY

In order to study DLR related line security constraints, an optimisation framework is developed for the planning of DLR and reconductoring. As this study involves DLR and wind generation, the framework is stochastically formulated based on weather and system load forecasts, using likely hourly forecast scenarios, to initialise the model (Fig. 1). In the absence of forecast information, historical data can be applied to develop the scenarios. Ambient temperature, wind speed,

solar irradiation and load profile time series are required. Scenario reduction is then implemented using the fast forward selection algorithm [6], with a finite number of representative hours selected for each year across the planning horizon. For each time step, as part of model initialisation, normal (steady-state) DLR ratings for individual lines are determined, along with the available wind power. DLR (short-term) emergency capacities are also calculated, as part of subsequent security assessment. Then, the optimisation process selects several candidate lines, where increased transfer capacity would be particularly beneficial, based upon the locational marginal price (LMP) difference at either end of each line normalised by the investment cost [7], in combination with contingency analysis results. Finally, among the various candidates, those lines which can better reduce the total cost, and, in parallel, fulfil the security constraints, are selected for modification.

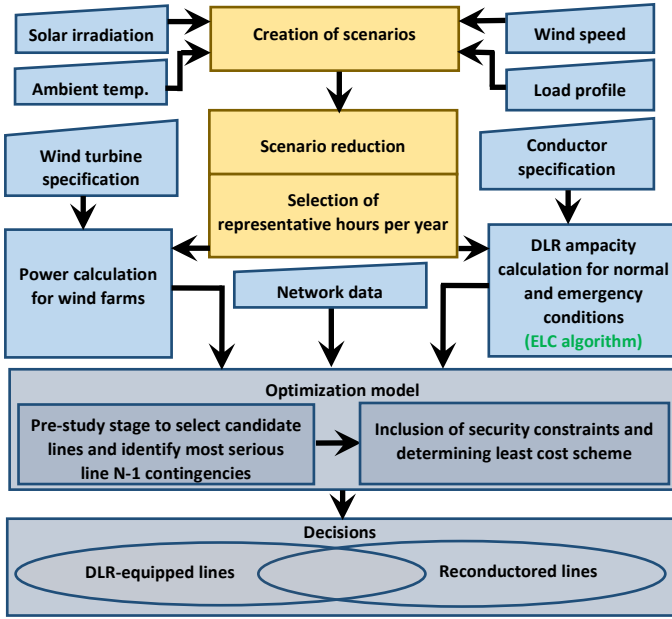


Fig. 1 Methodology flowchart

Candidate lines can also take advantage of staged investment (overlap area in 'decisions' block in Fig. 1), which implies that DLR could be applied to a candidate line, before, some time later, reconductoring is then introduced. Of course, considering an operational viewpoint, a number of scheduled outages would be required for DLR-equipped line(s), for section-by-section installation of the new conductor(s), taking note of seasonal peak load periods. A smooth transition could thus be achieved from the extra capacity provided by DLR, assuming the maximum practical DLR rating is comparable to the new conductor rating. In practice, the DLR uprating is restricted to 10-50%, due to limitations imposed by substation equipment ratings, voltage control, etc. and lies within the capacity range of most reconductoring projects [8], [9].

Normal DLR values are calculated based on steady-state heat balancing, whereby the resistive and solar heat gains balance the convective cooling and radiated heat loss:

$$R_{T_{C,max,n}} I^2 + q_s = q_c + q_r \quad (1)$$

where I is the electrical current, $R_{T_{C,max,n}}$, conductor electrical resistance at the maximum temperature $T_{C,max,n}$ for normal operation, q_s , solar heating, q_c , convective cooling, and, q_r , radiated heat loss. If the difference between the conductor surface and core temperature is greater than a permissible value, then, $T_{C,max,n}$ should be reduced through

an iterative process. Further details of this process, as well as q_c , q_r and q_s dependencies on weather conditions, can be found in [10]. For each representative hour, DLR time series are calculated, and then sent to the optimisation model. The wind attack angle is assumed to be zero to adapt DLR for all line directions.

Network N-1 security limits are investigated following preventative / corrective approaches. For the former, it is assumed that post-contingency line limits are equal to the steady-state limits, with no (temporary) overload capability, i.e. no immediate operator action required. In contrast, for the corrective approach, individual lines can be overloaded, post-contingency, for a short time (congestion clearing time, t_{cc}). During this period, the operator should re-dispatch generators, switch in/out lines, etc., to restore loadings back to normal limits. The corrective approach can be *dynamic*, i.e. the pre-contingency loading is considered, or, more pessimistically, *conservative*, whereby the pre-contingency loading is set at the maximum (normal) level, and the post-contingency value forms the emergency line limit.

Here, the burden of security implementation is partially placed in the pre-optimisation stage. For each line, given relevant weather conditions in each scenario, and, a presumed time limit, t_{cc} , emergency loading characteristics are obtained as permissible post-contingency loading vs. pre-contingency values (Table I). The emergency loading calculation (ELC) is initialised based on pre-contingency conditions, with the contingency loading progressively increased. The differential heat balance equation is solved for duration t_{cc} , with the initial temperature corresponding to the pre-contingency loading. Referring to Table I, line l is a member in the set of DLR candidate lines, with $I_{pre-max}$ representing the maximum permissible pre-contingency current obtained from DLR steady-state capacity calculations, $I_{pre-cont}$, discrete loop variable, with $T_{pre-cont}$ being the associated temperature. $T_{c,max,e}$ is the maximum (emergency) conductor temperature, $\Delta T_{core,max,e}$, maximum difference between the conductor surface and core temperatures, while I_{post} is an array of post-contingency loadings vs. pre-contingency values for line l and scenario sc . A concave function is fitted to the outputs, before being approximated with piecewise linear segments. This approach can be observed for a Dove conductor in Fig. 2, where $t_{cc} = 15$ min, $T_{c,max,n} = 100$ °C, $T_{c,max,e} = 110$ °C, $\Delta T_{core,max,e} = 10$ °C, ambient temperature = 15 °C, wind speed = 4 m/s, and, finally, solar irradiation. = 133 W/m². For other studied cases, the same temperature limits are assumed.

Table I. Emergency loading calculation (ELC) algorithm

ELC Algorithm: Calculation for line l and scenario sc	
1:	for $I_{pre-cont} = 0$ to $I_{pre-max}$ do step ΔI
2:	$I_p = I_{pre-max}$
3:	while (True) do step ΔI
4:	$I_p = I_p + \Delta I$
5:	solve $mc \frac{dT_c}{dt} = R_{T_c} I_p^2 + q_s - q_c - q_r$
6:	if $T_c(t = t_{cc}) < T_{c,max,e}$ and $\Delta T_{core} < \Delta T_{core,max,e}$ then
7:	Set $I_{post}[l, sc, I_{pre-cont}] = I_p$
8:	else
9:	break
10:	end if
11:	end loop
12:	next $I_{pre-cont}$

A quadratic function is used for least squares curve fitting. Preventative, conservative corrective and dynamic corrective emergency line limits are determined, Fig. 2, as $S_{pre-max}$ (apparent power associated with $I_{pre-max}$), $S_{post-min}$ and piecewise-linear segments based on a fitted quadratic curve.

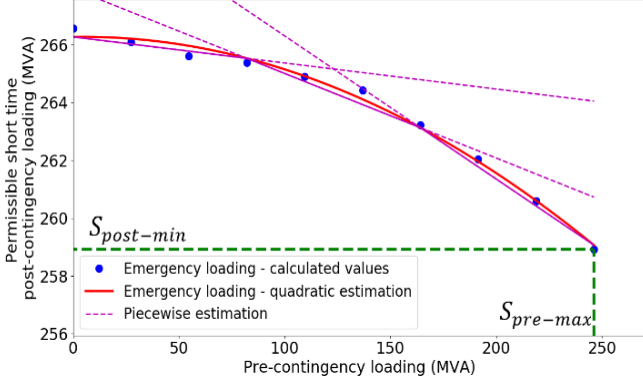


Fig. 2 Emergency loading fitted curve and piecewise linearisation

III. OPTIMISATION MODEL

An optimisation model is required which can efficiently select uprating options for those lines associated with network congestion. The objective is to minimise the summation of the combined investment cost, operational cost and load shedding penalties. The model needs to be stochastic in nature to recognise the uncertain wind generation profiles, and the weather impacts of wind-induced line cooling on DLR normal and emergency line ratings, while load and wind generation growth rates are assumed as known. A scenario reduction stage groups related scenarios, as discussed in Section II, with a weight, $w_{sc,y}$, associated with each reduced scenario, representing the relative importance of a representative hour (scenario sc) in year y [6]. In addition, a multi-year representation is utilised, which captures the year in which line modifications should be applied. The model is formulated using power transfer distribution factors (PTDFs), which, for a DC power flow framework, quantify the linear relationships between the power injections in the grid and the (active power) line flows [12]. It is assumed that individual line modifications have a low impact on PTDFs, but, pre-planned modifications which significantly affect the PTDFs, e.g. new line construction, can be included within the model. Problem tractability is achieved through decomposition using Benders approach [11]. Decision variables which relate to line modifications are placed in the master problem (MP), while, operational sub-problems (SPs) are defined for each planning year, being fed with higher level decision variables. Required cuts are identified as soon as the sub-problems are solved, and then added to the master problem for the next iteration. The process ends when the gap between the MP and SP solutions is less than a pre-defined value. Unit commitment decisions for the generators are implemented using integer variables at SP level, which results in a more complex mixed integer problem for Benders decomposition. In order to extract a valid optimality cut, a linear relaxation of a sub-problem (RSP) should also be solved, and to avoid looping, cuts with lower-bounding functions (LBF) should be added to the MP [11]. The sub-problems should be solved in each iteration, as part of evaluating the solution gap, although for the initial iterations this step can be skipped in order to accelerate cut generation. This procedure is shown in Fig. 3, with a parallelised style.

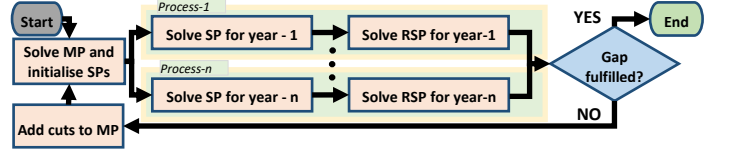


Fig. 3 Parallelised implementation of Benders decomposition

A. Model description

The objective function is written as follows:

$$GP: \text{Minimise } C_{total} = C_{Line\ modification} + C_{Operational} + C_{Load-Shed} \quad (2)$$

where $C_{line\ modification}$ represents the discounted capital cost for new assets, $C_{Operational}$ incorporates the combined operational (fuel) costs, and $C_{Load-Shed}$ represents load shedding penalties. The details for these costs are as follows:

$$C_{line\ modification} = \sum_{y(t)} \left(\frac{1}{1+dr} \right)^{t-1} \sum_l \sum_{lop} C_{l,lop} b_{l,lop,y(t)} \quad (3)$$

$$C_{Operational} = \sum_{y(t)} \left(\frac{1}{1+dr} \right)^{t-1} \sum_{sc} w_{sc,y} \sum_g C_g P_{G,g,y,sc} \quad (4)$$

$$C_{Load-Shed} = \sum_{y(t)} \left(\frac{1}{1+dr} \right)^{t-1} \sum_{sc} w_{sc,y} \sum_i C_{shed} P_{LSi,y,sc} \quad (5)$$

where dr is the discount rate, t is the year index, and $C_{l,lop}$ is the annualised capital cost of option lop for line l . C_{shed} is the load curtailment cost, C_g , the fuel cost for generator g , and $P_{G,g,y,sc}$, active power of unit g in year y , scenario sc , while $P_{LSi,y,sc}$ is the load shedding variable at bus i . Single and staged investments on the same line are formulated as:

$$\sum_{lop} b_{l,lop,y} \leq 1 \quad (6)$$

$$b_{l,lop,y} = b^+_{l,lop,y} - b^-_{l,lop,y} \quad (7)$$

$$b^+_{l,lop,y(t)} \geq b^+_{l,lop,y(t-1)} \quad (8)$$

$$b^-_{l,lop,y(t)} \geq b^-_{l,lop,y(t-1)} \quad (9)$$

$b^+_{l,lop,y}$ and $b^-_{l,lop,y}$ are auxiliary binary variables, which enable $b_{l,lop,y}$ to be activated, or deactivated, as required. Modifications are limited by (6) to one change per year, while (8) and (9) ensure that $b^+_{l,lop,y}$ and $b^-_{l,lop,y}$ remain high in years after first activation. In practice, should a line require both DLR and rectoring, DLR should be applied first:

$$b^+_{l,Recon,y} \geq b^-_{l,DLR,y} \quad (10)$$

Since rectoring represents the final solution and will not be deactivated, it is not then necessary to define $b^-_{l,lop,y}$ for rectoring, such that (7) and (9) are ignored. In addition, to restrict investment decisions to one upgrade per line, binary variable $b^-_{l,DLR,y}$ and constraints (9) and (10) are ignored. The line flow constraints are written as follows:

$$f_{l,y,sc} = \sum_i (P_{Gg(i),y,sc} - P_{Li,y,sc} + P_{Wi,y,sc} + P_{LSi,y,sc} - P_{WSi,y,sc}) PTDF_{li} \quad (11)$$

where $f_{l,y,sc}$ represents the power flow on line l , while at bus i , $P_{Li,y,sc}$ is the connected load, $P_{Wi,y,sc}$ the available wind output, and $P_{WSi,y,sc}$ the curtailed wind power. $PTDF_{li}$ is the

power transfer distribution factor for line l , considering the power injection at bus i , which can be calculated using the procedure outlined in [12]. For the normal line loading of any candidate lines, the following constraint is introduced:

$$|f_{l,y,sc,h}| \leq \sum_{lop} (f_{max_{l,lop}} - f_{max_l}) b_{l,lop,y} + f_{max_l} \quad (12)$$

In (12), f_{max_l} and $f_{max_{l,lop}}$ represent the maximum flow limit of line l , for the original line and after implementing option lop . For the DLR option, $f_{max_{l,lop}}$ values are pre-calculated as a time-series for each hour (Section II).

Security constraints are implemented using line outage distribution factors (LODFs), which provide DC power flow based linear relationships between the post-contingency loading of individual lines and the power flow of the out-of-service line before a contingency. LODFs can be calculated from the PTDF values [12]. The loadings of individual lines after a line outage can be calculated as follows:

$$f_{lm}^{post} = f_{lm}^{pre} + LODF_{lm,lo} f_{lo} \quad (13)$$

where $LODF_{lm,lo}$ is the line outage distribution factor for an outage of line lo and monitored line lm (a line which becomes highly loaded due to outage of line lo), f_{lo} line flow under outage lo , and, f_{lm}^{pre} and f_{lm}^{post} are the pre- and post-contingency loadings of the monitored line, lm . Line N-1 severe contingencies can be identified as ‘‘monitored line per line outage’’ pairs using (13), e.g. L08/L03, such that line L08 will be overloaded as a result of an outage on line L03, without solving another optimisation problem, and can be incorporated in the model as security constraints. These constraints, for the dynamic corrective scheme, are written as follows, for each piecewise-linear segment shown in Fig. 2:

$$|f_{lm,y,sc} + LODF_{lm,lo} f_{lo,y,sc}| \leq (\pm A_{p,lm,y,sc}) f_{lm,y,sc} b_{l',DLR',y} + (B_{p,lm,y,sc} - f_{max,e_l}) b_{l',DLR',y} + (f_{max,e_l,Recon'} - f_{max,e_l}) b_{l',Recon',y} + f_{max,e_l} \quad (14)$$

where $A_{p,lm,y,sc}$ and $B_{p,lm,y,sc}$ are the slope and intercept of linear segment p for scenario sc and year y . The negative sign for $A_{p,lm,y,sc}$ in (14) implies that a similar inequality with $-A_{p,lm,y,sc}$ is required. $f_{lm,y,sc}$ and $f_{lo,y,sc}$ are the power flows for the monitored line and the line under outage (before the outage), while f_{max,e_l} and $f_{max,e_l,Recon'}$ are the maximum emergency limit for line l for the original and reconducted cases. In addition, multiplying the binary variable $b_{l',DLR',y}$ and the continuous variable $f_{lm,y,sc}$ can be conveniently linearised. For the conservative corrective and preventative schemes, the right hand side of (14) should be reformulated to exclude the $f_{lm,y,sc}$ term and instead include $S_{post-min}$ and $S_{pre-max}$ (Fig. 2). Moreover, a convenient unit commitment procedure is achieved using the following constraints:

$$U_{g,y,sc} P_{g,min} \leq P_{G,g,y,sc} \quad (15)$$

$$P_{G,g,y,sc} \leq U_{g,y,sc} P_{g,max} \quad (16)$$

where $U_{g,y,sc}$ is an integer variable representing the number of online units, while $P_{g,min}$ and $P_{g,max}$ are the minimum and maximum generation output for generator group g .

B. Master problem (MP) formulation

Benders decomposition is now applied to the GP developed in Section III.A, with the master problem objective function as:

$$MP: \text{Minimise } C_{MP} = C_{Line\ modification} + \sum_y Z_y \quad (17)$$

subject to:

(3), (6)–(10) and (18) for each sub- problem for each iteration

where Z_y is associated with SP(y) for each iteration, with an optimality cut obtained from solving the RSP for year y :

$$Z_y \geq C_{RSP,y} + \sum_{l,lop} \lambda_{l,lop,y}^0 (b_{l,lop,y} - b_{l,lop,y}^0) \quad (18)$$

$b_{l,lop,y}$ represents a binary decision variable for implementing option lop for line l in year y (e.g. DLR or reconducting). $C_{RSP,y}$ represents the objective cost for sub-problem RSP(y), $\lambda_{l,lop,y}^0$ the marginal value for the associated $b_{l,lop,y}$ equality, introduced later in Section III.C, while, $b_{l,lop,y}^0$ is the initial solution from the previous MP iteration.

C. Sub problem (SP) and relaxed SP formulation

The sub-problem for year y is defined as follows, along with the weighted operational and load shedding costs:

$$SP(y): \text{Minimise: } C_{SP,y} = C_{Operational,y} + C_{Load-Shed,y} \quad (19)$$

subject to:

(4), (5), (11)–(16) and (20)

where $C_{Operational,y}$ and $C_{Shed,y}$ are defined for the particular year y . The following equality is also required in the sub-problems in order to initialise them from the MP solution:

$$b_{l,lop,y} = b_{l,lop,y}^0 : \lambda_{l,lop,y} \quad (20)$$

The SP is a mixed-integer problem, and marginal values for the above equations are linked to an equivalent relaxed SP (RSP), formulated similar to the SP, but with relaxed integral constraints relating to switching variables defined in (15), (16).

The gap after iteration k is calculated as follows:

$$Gap_k = \frac{\min(C_{Line\ modification} + \sum_y C_{SP,y,k}) - C_{MP,k}}{C_{MP,k}} \quad (21)$$

'min' refers to the minimum value across all iterations, which is assumed to be achieved in iteration h ($h < k$). As soon as Gap_k becomes less than a threshold, the process stops and iteration h will be considered as the optimal solution.

IV. CASE STUDY

The performance of the proposed approach is now assessed based upon the IEEE RTS 24 bus system depicted in Fig. 4 [6]. A planning horizon of 10 years is assumed. Dove and Curlew conductors have been selected for the 138 kV and 230 kV lines. The system peak load is initially assumed as 1570 MW, with an annual growth rate of 4%. Annual historical load profiles for the Irish grid are utilised and scaled to match the defined load peak. Four wind farms are also placed at selected buses, to effectively create ‘‘wind rich’’ regions, and, sized relative to local network strength. Annual wind power capacity growth is set at 6%. The generators at Buses 02, 18, 21 and 22 are considered as must-run units. Wind speed time series, required for wind generation and DLR calculations, are adjusted for wind turbine hub and line conductor heights [13]. Input data for wind speed and ambient temperature were obtained from 3 weather stations in Ireland [14], mapped to the two wind-rich regions and the remaining transmission system. Maximum hourly solar

irradiation was calculated based on Ireland's latitude [10]. Hence, DLR estimates are slightly conservative, and, to account for the errors, they are scaled by a factor of 0.9.

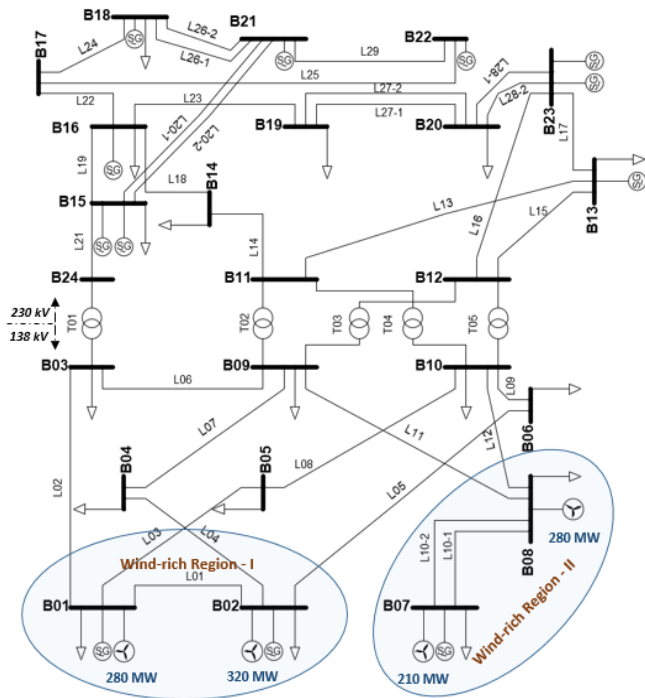


Fig. 4 Modified IEEE RTS 24 bus network

V. RESULTS

Congestion problems are first investigated for the base case, leading to candidate lines being identified for the most severe scenarios. Different security schemes, i.e. preventative, dynamic corrective, and conservative corrective, are then investigated, as part of single or staged investment planning. ACSR reconductoring is assumed to provide 40% capacity beyond the unmodified line, with a similar maximum capacity uprating for DLR-equipped lines, as seen in Section II. A capital investment discount rate of 5% is considered. For the corrective scheme, 10% extra capacity is temporarily assumed for both the existing and reconductored lines. For the dynamic and conservative corrective schemes, the emergency limits for DLR-equipped lines are obtained from the ELC algorithm and the least post-contingency loading ($S_{post-min}$), but for the preventative scheme, the steady-state values are utilised.

Load curtailment is permitted, but with a penalty cost of 90,000 €/MWh, with the gap set to 0.40% for Benders algorithm. The framework has been developed and optimised using multi-processing and socket programming in Python 3.7, and the Gurobi 9.0.1 solver, and run on a server with Intel Xeon Processor E5-2697 v2 12 cores and 256 GB RAM.

A. Base case

For the original case, optimal power flow is performed without considering any network modifications or security constraints, i.e. ignoring (17). The error in the objective cost (total cost formulated in (2) without modification cost) for a limited number of scenarios, i.e. 25 to 3200 hours per year, relative to including all scenarios, is evaluated in a range between 2.42% and 0.05%. 200 hours per year is adopted with a relative error of 0.28%, in which no load shedding occurs.

In addition, using LODFs and (13), 218 and 62 contingency pairs are identified as N-1 line severe outages, for the preventative and corrective schemes. In order to ensure

system robustness, specific security constraints, based on the above associated pairs, are added to the base case for each scheme. In year 1, the system is totally secure without any load shedding. However, with load growth in later years, load shedding gradually becomes necessary to maintain security. Hence, in the final year, load curtailment levels of 1.00% and 0.40% of annual demand are required at Bus 05 to fulfill the preventative and corrective constraints, due to the severe congestion on L03 and L08. Finally, 21 and 23 candidate lines are identified for corrective and preventative upgrades using the LMP criterion, in conjunction with the set of monitored lines obtained from the contingency pairs (Section II).

B. Alternative security schemes

The security schemes, i.e. dynamic and conservative corrective, and preventative, along with different investment strategies, i.e. single and staged, are now compared. Initially, the emergency loading line limits are identified using the ELC algorithm (Section II), with a quadratic curve fitted for each scenario. For Dove and Curlew conductors, the R2, average weighted coefficient of determination, follows as 0.968 and 0.977, indicating acceptable fitting. Subsequently, linearising the quadratic curve(s) using 4 piecewise linear segments leads to an error less than the assumed Benders gap, which is later applied for the dynamic corrective scheme.

The benefits of staged investment are first investigated, i.e. DLR is applied before reconductoring for individual lines. For all the security schemes, load shedding isn't required, with the optimisation results, i.e. capital and operational costs detailed in (3) and (4), shown in Fig. 5. The total cost for the conservative scheme is 1.91% higher than the dynamic approach, although the computation time for the ELC algorithm and subsequent optimisation is much lower ($\approx 50\%$).

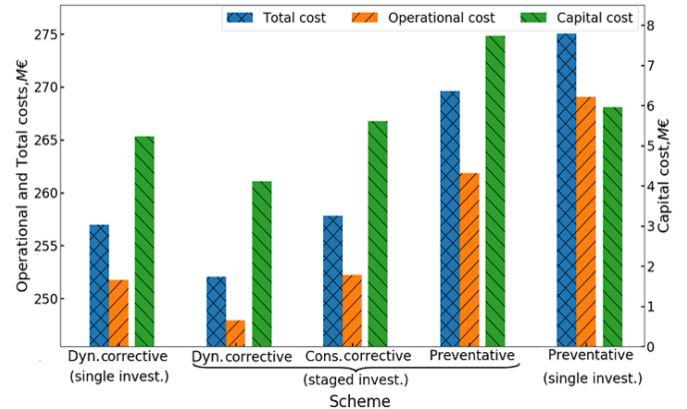


Fig. 5 Cost comparison between different schemes

The preventative scheme, due to applying the lowest emergency transmission capacities, results in the highest investment and total cost, i.e. 79.53% and 6.18% higher than equivalent figures for the dynamic corrective scheme. As seen in Fig. 5, a single investment approach is more costly, since by enabling the option of additional investments for individual lines, total cost savings of 2.16% and 1.88% are achieved with the preventative and dynamic corrective schemes.

Annual wind curtailment is shown in Fig. 6, and it is noted that achieving zero wind curtailment is not a direct planning optimisation objective. Indeed, 5.37% wind curtailment occurs in the base case (year 1), which is assumed to be economically acceptable for wind developers. For the no investment options, wind curtailment levels trend upwards in successive years, since the assumed growth rate for wind

capacity is higher than that for the load, reaching up to 13.27% in the final year for the preventative scheme.

When investment on individual lines is permitted, however, wind curtailment is noticeably lower, hitting 4.78% and 6.03% for the staged dynamic corrective and preventative schemes in year 10. Staged investment is more effective in the earlier years in reducing curtailment, due to flexibility for early DLR deployment, while reconductoring (applied in all cases) ultimately leads to similar curtailment levels in the later years for the single and staged approaches.

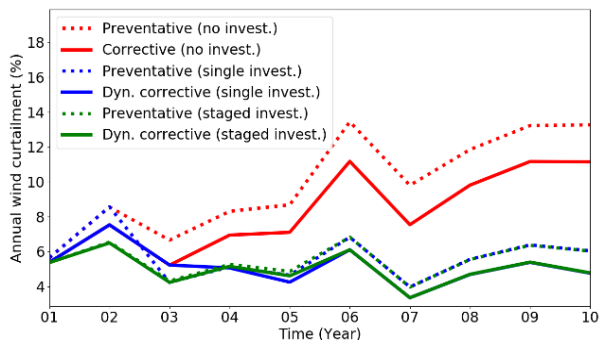


Fig. 6 Annual wind energy curtailment

Staged investment for the corrective dynamic scheme is shown in Fig. 7. Operational cost savings are obtained due to the installation of DLR in the initial years (L03, L19 and L22), and, deferral of reconductoring investments, supported by partial or complete DLR equipment redeployment. The latter occurs when new conductors appear in service, associated with the general increase in wind capacity and system demand (years 3 and 6). Increased line flows are also likely to occur in other lines, where DLR systems can be suitably re-deployed.

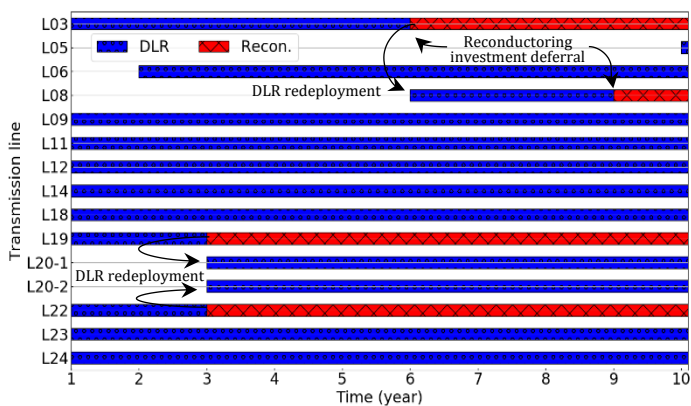


Fig. 7 Dynamic corrective scheme and staged investment

VI. CONCLUSIONS

With the main study goal of developing different line emergency security schemes as part of DLR based planning studies, a MILP model was formulated, comprising unit commitment, and solved using Benders decomposition. In the presented work, much of the DLR security assessment is transferred to a pre-optimisation stage, with the fitted concave curves piecewise linearised for optimisation. It is not necessary here to simplify the differential heat balance equation, so the obtained accuracy only depends on the concave curve fit, and the number of piecewise segments.

A formulation for staged investment on individual lines was also presented, with the objective of economically and flexibly resolving anticipated future congestion problems, through fast installation of DLR schemes, supported by later reconductoring investment, and potential redeployment of

DLR equipment to other lines. Here, constant growth rates were assumed for wind generation and load growth. As part of future work, alternative scenarios for wind and load forecast projections will be incorporated through a multi-stage planning study, with a sensitivity analysis for decisions made.

APPENDIX I

Asset*	Cost (138 kV)	Cost (230 kV)	Delivery time
Upgrading	150,000 €/km	200,000 €/km	3 years
DLR	6,500 €/km	6,500 €/km	1 year

* lifetime for all assets is assumed as 30 years

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