Corrective Control With Transient Assistive Measures: Value Assessment for Great Britain Transmission System

Yousef Pipelzadeh, *Member, IEEE*, Rodrigo Moreno, *Member, IEEE*, Balarko Chaudhuri, *Senior Member, IEEE*, Goran Strbac, *Member, IEEE*, and Tim C. Green, *Senior Member, IEEE*

***Abstract*—In this paper, the efficacy and value of using corrective control supported by transient assistive measures (TAM) is quantified in terms of the cost savings due to less constrained operation of the system. The example TAM is a rapid modulation of the power order of the high-voltage direct current (HVDC) links in the system so as to improve transient stability during corrective control. A sequential approach is used for the offline value assessment: a security constrained economic dispatch (SCED) module (master problem) determines the optimal generation dispatch, HVDC settings, and the corrective control actions to be used post-fault (generation and demand curtailed) so as to minimize the operational costs while ensuring static security. The transient stability module (slave problem) assesses the dynamic stability for the operating condition set by the SCED and, if needed, applies appropriate TAM to maintain the system transiently stable. If this is not possible, the master module uses a tighter set of security constraints to update the dispatch and other settings until the system can be stabilized. A case-study on the Great Britain system is used to demonstrate that corrective control actions supported by TAM facilitate significantly higher pre-fault power transfers whilst maintaining N-2 security.**

***Index Terms*—Transient stability, HVDC transmission, FACTS, economic dispatch, corrective control, system security, power system economics.**

NOMENCLATURE

A. Parameters

$\underline{d_n}$ Demand in node n $[MW]$

$\overline{f_k^{DC}}$ Capacity of DC line k $[MW]$

$\overline{f_l^{AC}}$ Capacity of AC line l $[MW]$

$h_{l,n,s}$ Power transfer distribution factor (PTDF) of line l and node n in state s $[p.u.]$

$itrp_{g,s}^{St(j)}$ Intertrip action applied to generator g in state s and determined after stage j $[MW]$

$\underline{p_g}, \overline{p_g}$ Minimum and maximum allowed power output of generator g $[MW]$

res_a Reserve requirements in area a $[MW]$

X_l^{AC} Reactance of AC line l $[p.u.]$

X_l^{FACTS} Reactance of FACTS device determined after stage 2 $[p.u.]$

$X_l^{min/max}$ Minimum and maximum reactance of FACTS device installed in line l $[p.u.]$

$\alpha_{l,s}$ Factor of FACTS device installed in line l used to compute its contribution to state s $[p.u.]$

ΔT_b Power reduction in critical boundary b to increase system stability $[MW]$

π_n^D Price of holding demand response services provided in node n [£/*MW/h*]

π_g^G Variable cost of generator g [£/*MWh*]

$\pi_g^{R.up}$ Price of holding up reserve services provided by generator g [l£/*MW/h*]

$\pi_g^{R.dw}$ Price of holding down reserve or intertrip services provided by generator g [£/*MW/h*]

B. Variables

$f_{l,s}^{AC}$ Power flow in AC line l in state s (without contribution from potential FACTS device installed in line l) $[MW]$

f_k^{DC} Power flow in DC line k (in pre and post-fault condition) $[MW]$

$f_{l,s}^{FACTS}$ Power flow contribution of FACTS device installed in line l in state s $[MW]$

$ll_{n,s}$ Lost load (demand response) in node n and state s $[MW]$

ll_n^{hold} Volume of holding demand response/ curtailment services provided in node n $[MW]$

p_g Power output of generator g in pre-fault condition $[MW]$

p_n^{node} Aggregated power output in node n in pre-fault condition $[MW]$

T_b^i Power transfer through major transmission boundary b in iteration i $[MW]$

Manuscript received January 5, 2016; revised June 2, 2016; accepted July 23, 2016. Date of publication August 9, 2016; date of current version February 16, 2017. This work are supported by Project HubNet Supergen+ EP-M015025-1 and Project HubNet EP-I013636-1 funded by the U.K. Research Council. The work of R. Moreno was supported by Conicyt-Chile under Grant Fondecyt-Iniciacion-11130612, Grant Newton-Picarte-MR-N026721-1, Grant Fondef-ID15I10592, and Grant SERC Fondap-15110019, and the Complex Engineering Systems Institute [ICM:P-05-004-F, Conicyt:FBO16]. Paper no. TPWRS-00025-2016.

Y. Pipelzadeh, B. Chaudhuri, G. Strbac, and T. C. Green are with the Department of Electrical and Electronic Engineering, Imperial College London, London SW7 2AZ, U.K. (e-mail: y.pipelzadeh08@imperial.ac.uk; b.chaudhuri@imperial.ac.uk; g.strbac@imperial.ac.uk; t.green@imperial.ac.uk).

R. Moreno is with the Department of Electrical Engineering (Energy Center), University of Chile, Santiago 6640871, Chile, and also with Imperial College London, London SW7 2AZ, U.K. (e-mail: rmorenovieyra@ing.uchile.cl).

Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TPWRS.2016.2598815

γ_g	Commitment status of generator g (same pre and post-fault unless unit is tripped) $[binary]$
$\Delta p_{g,s}$	Power output change of generator g from pre to post-fault state s $[MW]$
$\Delta p_{n,s}^{node}$	Aggregated power output change in node n from pre to post-fault state s $[MW]$
$\Delta p_g^{R.up.hold}$	Holding volume of up reserve services provided by generator g $[MW]$
$\Delta p_g^{R.dw.hold}$	Holding volume of down reserve services provided by generator g. This also accounts for cost of intertrip. $[MW]$

C. Sets

A	Set of reserve areas
B	Set of critical transmission boundaries
G	Set of generators
G_a	Set of generators in area a
G_n	Set of generators in node n
$GS^{itrp-St(v)}$	Set of pairs (g, s) where generator g is intertripped in state s which is determined in optimization stage v
L^{AC}	Set of AC lines (with and without FACTS devices)
L^{DC}	Set of DC lines
L^{FACTS}	Set of lines with FACTS devices
N	Set of nodes
S	Set of states
to_y	Node to which network component y is connected
$from_y$	Node from which network component y is connected
$(W)^c$	Complement of set W

I. Introduction

In many regions of the world, there is strong pressure to use a range of advanced, technically effective and economically efficient corrective (or post-fault) actions to release latent transmission network capacity of the existing system, reduce network congestion and hence accommodate increased connection of low-carbon generation without the need for costly network investment. This leads to the utilization of the transmission infrastructure to facilitate the highest possible power transfers and where limits are in place below the full thermal rating of the lines, measures should be taken to raise those limits.

In Great Britain, power transfer between Scotland and England/Wales is a key concern (Scotland-England system can be seen as a two-area system with dominant transfers mainly due to wind power from Scotland to England). There are two 400 kV double-circuit AC routes across the Anglo-Scottish boundary (known as the $B6$ boundary by the system operator, National Grid). Each of the four circuits has a thermal rating of 2.2 GW giving an N-2 transfer capability of 4.4 GW [1]. However, transfer is in fact limited to 3.4 GW because of a transient (first-swing) stability concern [2] which arises after a double-circuit fault. Two significant expansion measures will be commissioned [1]. The first, in 2016, comprises series compensators which will lift the stability limit and allow a transfer of 4.4 GW in preventive mode (i.e. without considering post-fault actions). The second, in 2017, is a 2.0 GW DC-link, the Western Link [3], which connects Scotland to England. With the series compensators in place the transfer limit will be the thermal N-2 limit of 4.4 GW. With the series compensators and DC-link in place (which is a bi-pole and effectively a double-circuit), the N-2 limit is raised to 6.4 GW (considering a 4.4 GW limit through the AC corridors and 2.0 GW limit through the DC-link) [1].

The limits described for the GB system are all based on preventive control, that is, the system is stable for credible contingencies such as a double-circuit outage without the need for corrective, post-contingency actions. Hence there is an opportunity to raise the pre-fault transfer limit further by using appropriate corrective control, decreasing the cost of network congestion and maintaining adequate system stability levels in the post-fault condition (avoiding situations such as breach of an angle stability limit). The corrective control can take the form of generation/load tripping [4], [5], control of HVDC power order [6]–[9], FACTS devices [10], [11], dynamic line ratings [12].

Taking the GB system (including Western Link and series compensators) as an example, the corrective control in response to a double-circuit outage would comprise in reducing the post-fault power transfer by generation curtailment in Scotland with a matching volume of load curtailment in England/Wales to 6.4 GW in total through AC corridors and DC-link (equivalent to 4.4 GW through the AC corridors) to stay within the thermal and stability limit of the remaining system. Through this approach, corrective control can help increase the pre-fault power transfer level without compromising security, provided that post-fault transfer is below 4.4 GW in the AC corridors by using appropriate generation/demand curtailment actions.

However, activation of corrective control action is dependent on fast communication of line outage (i.e. circuit breaker status) information to all the participating generators and demand aggregators spread across the system. Even with dedicated communication infrastructure, there could be a latency of up to 250 ms between fault clearance and activation of corrective control [13]. The latency could be higher for commonly used shared communication, which would adversely affect transient (or first-swing) stability control.

In this context, the aim of this paper is to quantify the efficacy and value of using "Transient Assistive Measures" (TAM) such as rapid modulation of the power orders of Western HVDC link and HVDC interconnectors to demonstrate that corrective control actions supported by TAM facilitates a significantly higher pre-fault power transfer between Scotland and England/Wales whilst maintaining N-2 security. Supplementary control of HVDC/FACTS for transient stability improvement has been reported in several papers [9], [14]–[18] and recently, in [19], [20] as TAM. However, not much has been done to quantify the actual value of using such supplementary control TAM by combining security constrained economic dispatch (SCED) with stability analysis, fully coodinating robust generation dispatches and setpoints of flexible network devices against pre- and post-fault conditions. In order to quantify the value of using TAM, we use a sequential approach (see Fig. 1) where a (master) security constrained economic dispatch (SCED) module determines the generation dispatch, settings of FACTS devices,

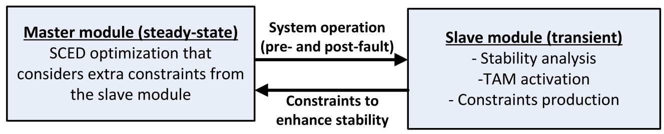

Fig. 1. Overview of proposed assessment methodology.

HVDC power order and also the amount of post-fault corrective control actions (generator tripping and demand curtailment) to minimize the operational costs while ensuring static security for a snapshot of the demand/wind profile [21]. The (slave) transient stability module ascertains whether the dispatch condition set by the SCED module is dynamically stable following the critical contingencies. Otherwise, an array of TAM are applied by the slave module to support the corrective control action in order to ensure transient stability for the dispatch condition set by the master module. If it turns out that the TAM together with the corrective control is unable to maintain transient stability, a tighter set of security constraints is used by the master module to find new dispatch/settings until the system can be stabilized dynamically. Although primary corrective control actions (e.g. generation and demand curtailment) are determined in the master module, TAM (e.g. post-fault changes in set-points of the Western HVDC link and cross-border interconnectors) are determined in the slave module since they are not needed from a steady-state perspective. Furthermore, TAM last only for a few seconds to tackle the transient stability problem. It should be noted that the sequential master-slave approach used in this paper is aimed at assessing the value of TAM in an offline context (e.g. time-ahead operational planning) and is not necessarily suited for real-time operation. Advanced techniques for online dynamic security assessment (such as trajectory sensitivity) could be used for near-real time implementation which however, is not the focus of this paper.

In [7], [22], corrective control action through Western HVDC link in Great Britain was demonstrated with an over-simplified equivalent model of the Great Britain transmission system. No generator tripping or demand curtailment was considered and the role of the HVDC interconnectors were ignored which resulted in only moderate increase in pre-fault power transfer levels. In this paper, a case study on the 2850-busbar equivalent model of Great Britain transmission system is presented to demonstrate the value of using TAM to support the post-fault corrective control actions based on generation tripping and demand curtailment. This can allow up to 6.0 GW pre-fault power transfer through the double circuit AC routes between Scotland and England/Wales whilst maintaining $N-2$ security. This is over 1.6 GW on top of 4.4 GW which could be transferred with the planned series compensators pushing the stability limit close to the thermal limit. The post-fault corrective control alone, without TAM, is not adequate in ensuring transient stability beyond 4.9 GW pre-fault transfer. Hence, use of TAM could potentially result in an extra power transfer of up to 1.1 GW. The benefit of using corrective control actions accompanied by TAM is quantified in terms of costs (k£/hr). It is also demonstrated that use of TAM could minimize the risk of instability when corrective control action is delayed due to problems in communication infrastructure. This study highlights the need for using TAM together with corrective control to ensure $N-2$ secure operation of the Great Britain system while transferring more than 4.4 GW through the two 400 kV double-circuit AC routes across the Anglo-Scottish $B6$ boundary.

The novel contributions in this paper are outlined below:

1) Quantify the value of using TAM to support the corrective control in terms of the cost savings due to less constrained operation of the system.
2) Use a sequential master–slave approach to consider the effect of TAM on transient stability together with security constrained economic dispatch (SCED) in order to assess the actual value of TAM.
3) Include corrective control actions, setting of FACTS device, HVDC power order within the security constrained economic dispatch (SCED) formulation and keep it mathematically tractable for large scale problems (e.g. a detailed realistic representation of the Great Britain transmission system). This is achieved by eliminating the need to define a larger set of binary variables (those associated with FACTS/HVDC – expanding on [23] – and generation tripping) and further avoiding the non-linear optimization models by decoupling key decisions in various stages.

In the remaining of this paper, we use the following definition of the various post-contingency actions that are carried out to secure system operation: (i) fault clearance, which is rapidly applied following a short circuit through a local protection to isolate the outaged line; (ii) TAM that include very fast responses from set points of HVDC links and cross-border interconnectors, which are applied through wide-area control systems after the fault is cleared and (iii) primary corrective control actions composed of generation and demand curtailments (or trips) in exporting and importing areas, respectively through application of special protection schemes. TAM are activated earlier than the primary generation/demand curtailment actions since the formers rely on power electronics rather than switch openings. Hence TAM correspond to measures aiming to assist or complement the set of primary control actions (that are slower) and thus stabilize the system operation. For this reason, TAM are *temporary* measures and thus last for a few seconds only (i.e. after system operation has been stabilized, TAM disappear, while the primary corrective control actions are more *permanent* (since these aim at managing network congestion in the post-fault, steady state condition).

II. Assessment Methodology

Our sequential master-slave approach (shown in Fig. 1) is divided into various stages that aim at decoupling key decisions and thus simplifying the assessment methodology to value the benefits associated with the application of corrective control and TAM, which is described next.

A. Master Module: Security Constrained Economic Dispatch

From an optimization viewpoint, coordinating system operation (generation, network and demand) in terms of active and reactive power and in both pre- and post-fault conditions over a large-scale transmission network remains a challenge. In this paper, we decouple several decisions to make the optimization problem tractable as follows:

i) *Active/reactive power decoupling:* security constrained economic dispatch is obtained through a linear DC power flow approximation (which allows us to find optimal decisions against a larger set of line failures) which is then complemented by a Newton-Raphson calculation to obtain meaningful reactive power solutions (for the given set of active powers).

ii) *Transfer direction/volume decoupling:* assuming power flow directions as known parameters in those lines with FACTS devices installed allows reducing the complexity of the optimization problem and speed up its calculation.

While DC power flow undertaken in i) is a well-known and widely used approximation, especially to undertake economic analyses (see for example [21]); ii) has recently been proposed by [23], which demonstrated successful results. In this paper, we expand the propositions in [23] (that develops the idea to use engineering insights to eliminate the need for binary variables associated with FACTS) to eliminate the use of binary variables associated with both generation intertrips and FACTS in a security constrained economic dispatch model. In the GB case, this represents a saving of 14592 binary variables that are eliminated from the model. Next, we further explain: 1) optimization model related to the security constrained economic dispatch through DC power flow approximation (where directions and volumes of transfers are first determined separately in those lines with FACTS devices), and 2) the Newton-Raphson calculation.

1) Steady-State DC Power Flow Optimization Model: This section presents a 3-stage cost minimization model to determine the most economically efficient dispatch solution that can withstand a set of credible network faults without overloading the remaining network infrastructure. Together with preventive control actions that aim at derating power flows through main network boundaries in order to ensure system security against network faults, the model also deploys a set of corrective control actions based on contracted demand and generation volumes that can be curtailed through Special Protection Schemes (SPS). The objective function of the model includes the following cost components:

1) *Generation fuel cost (and network congestion cost)*: which increases when transfers are limited (and thus network is congested) due to security reasons. For wind generation, we multiply production by the negative values associated with their subsidies. Then, the congestion cost can be determined as the difference between generation fuel costs with and without capacity network constraints.
2) *Generation inter-trip contracts*: necessary to curtail generation in exporting areas after a network fault occurs in order to eliminate post-fault network overloads.
3) *Demand curtailment contracts:* necessary to curtail demand in importing areas after a network fault occurs and thus balance the system when a generating unit is tripped in an exporting area.
4) *Generation reserves:* which account for the costs associated with the needed headroom in generating units that is used to deal with generation outages. Although we do not model generation outages, we impose reserve requirements per area in order to obtain a more realistic dispatch solution and thus a more accurate cost estimate.

Thus, to provide security of supply the model can decide to either (i) limit power transfers during pre-fault conditions and thus increase cost of congestion, or (ii) contract generation and demand volumes that can be exercised/curtailed in post-fault conditions to eliminate network overflows and thus increase power transfers during pre-fault, and these decisions will depend on market prices. Hence as costs of holding corrective actions (demand and generation reduction/curtailment) are part of the objective function, they are adequately optimized and balanced against the cost of preventive control actions (i.e. network congestion); and although there are important benefits associated with reducing congestion, this may drive higher holding levels of corrective control actions that can also be costly, and this is properly considered in the SCED model. We eliminated the need to define a larger set of binary variables by undertaking a three-stage process that:

1) Optimizes pre- and post-fault system operation while ignoring both effects of FACTS devices and the binary nature of generation curtailment and this is done in order to determine: (a) power flow direction of lines with FACTS and (b) volumes of needed generation curtailments (that in this stage are modeled as continuous variables).
2) Optimizes pre- and post-fault system operation when considering direction of power flows in those line with FACTS devices installed and volumes of generation curtailment as a set of given parameters (obtained in previous stage). This stage aims to determine set-points of FACTS devices in pre-fault (which remain constant during post-fault). Effects of FACTS devices on post-fault transfers are approximated through linear functions derived from previous stage.
3) Optimizes pre- and post-fault system operation when considering set-points of FACTS devices as a given set of parameters that are fixed during pre- and post-fault.

Note that stage 1 and 2 represent the application of concepts derived in [23] where intertrip actions have also been included. Set-points of FACTS devices determined in stage 2 and 3 are the same during pre- and post-fault conditions. Stage 3 obtains a valid economic dispatch solution for a given array of setpoints of FACTS devices (i.e. fixed rather than controllable reactance) and this stage is needed since effects of FACTS on post-fault power transfers were approximated in stage 2.

The detailed mathematical formulation of these 3 stages is presented through Eqs. (1)–(23), where Eq. (1) is the objective function. Eq. (2) maintains the supply-demand system balance during pre- and post-fault conditions. Capacity constraints are represented through Eqs. (3), (4) for generating units and Eqs. (5)–(7) for AC and DC lines. In Eq. (7), we assume a power injection representation (used, for example, in [24]) for power transfers through lines with FACTS devices, where the power flow component associated with a FACTS device in a line is isolated in the term $f_{l,s}^{FACTS}$. Eqs. (8)–(10) are used to compute the power flows through PTDF, and Eqs. (11)–(13) are used to maintain certain holding/contracted levels of corrective control measures that can be used post-fault. Eq. (14) aims at neglecting effect of FACTS in stage 1. In stage 2, we trip those generating units whose post-fault outputs were reduced below their minimum stable generation levels in stage 1 (note that this can occur since Eq. (4) does not consider $\underline{p_g}$) and this is done through Eqs. (15), (16). Note that this is an approximation which is undertaken to eliminate the need to define more binary variables in stage 1 (representation of intertrip actions as a set of binary variables can be found in [21]). Eqs. (17), (18) replace Eq. (14) and allow FACTS to control the power flows through a line within a given range that depends on maximum and minimum reactance values of the device. Eqs. (17), (18), however, are used during pre-fault condition only and Eq. (19) is used in post-fault condition where contribution of a FACTS device to a lines power flow is equal to the proportion of the angle difference between post- and pre-fault conditions observed in stage 1 ($\alpha_{l,s} = f_{l,S}^{AC} / f_{l,1}^{AC}$), multiplied by the contribution of a FACTS device to a line's power flow during the pre-fault condition in stage 2 (FACTS device is not re-optimized post-fault but rather maintains the same setpoint determined during pre-fault). Note that although Eqs. (17), (19) are presented in a preventive control fashion (since FACTS set-points are kept constant from pre- to post-fault), post-fault corrective control mode can be enabled by application of Eqs. (17), (18) to all network states (relaxing Eq. (19)), allowing the model to re-optimize FACTS set-points according to the particular congestion conditions during post-fault. Corrective control mode of FACTS is not used in the case of GB due to its network topology and location of TCSC (which will be disconnected in the worst-case outage scenario, against which we seek to protect the system). In stage 3, Eqs. (20), (21) are similar to Eqs. (15), (16) in stage 2, where Eq. (22) is added to avoid further intertrip actions in stage 3. Eq. (23) fixes reactance values of FACTS devices to those levels obtained from stage 2.

a) Stage 1

$$\min\left\{\sum_{g\in G}\pi_g^G\cdot p_g+\sum_{g\in G}\pi_g^{R.up}\cdot\Delta p_g^{R.up.hold}+\sum_{g\in G}\pi_g^{R.dw}\cdot\Delta p_g^{R.dw.hold}+\sum_{n\in N}\pi_n^D\cdot ll_n^{hold}\right\} \quad (1)$$

s.t.

$$\sum_{g\in G}p_g+\sum_{g\in G}\Delta p_{g,s}=\sum_{n\in N}(d_n-ll_{n,s})\quad\forall s\in S \quad (2)$$

$$\gamma_g\cdot\underline{p_g}\le p_g\le\gamma_g\cdot\overline{p_g}\qquad\forall g\in G \quad (3)$$

$$0\le p_g+\Delta p_{g,s}\le\gamma_g\cdot\overline{p_g}\qquad\forall g\in G,\forall s\in S \quad (4)$$

$$-\overline{f_k^{DC}}\le f_k^{DC}\le\overline{f_k^{DC}}\quad\forall k\in L^{DC} \quad (5)$$

$$-\overline{f_l^{AC}}\le f_{l,s}^{AC}\le\overline{f_l^{AC}}\ \forall l\in L^{AC}\backslash L^{FACTS},\forall s\in S \quad (6)$$

$$-\overline{f_l^{AC}}\le f_{l,s}^{FACTS}+f_{l,s}^{AC}\le\overline{f_l^{AC}}\qquad\forall l\in L^{FACTS},\forall s\in S \quad (7)$$

$$f_{l,s}^{AC}=\sum_{n\in N}h_{l,n,s}\cdot\Big(p_n^{node}+\Delta p_{n,s}^{node}+\sum_{k\in L^{DC}|to_k=n}f_k^{DC}+\sum_{j\in L^{FACTS}|to_j=n}f_{j,s}^{FACTS}-(d_n-ll_{n,s})-\sum_{k\in L^{DC}|from_k=n}f_k^{DC}-\sum_{j\in L^{FACTS}|from_j=n}f_{j,s}^{FACTS}\Big)\quad\forall l\in L^{AC},\forall s\in S \quad (8)$$

$$p_n^{node}=\sum_{g\in G_n}p_g\quad\forall n\in N \quad (9)$$

$$\Delta p_{n,s}^{node}=\sum_{g\in G_n}\Delta p_{g,s}\quad\forall n\in N,\ \forall s\in S \quad (10)$$

$$res_a\le\sum_{g\in G_a}\Delta p_g^{R.up.hold}\quad\forall a\in A \quad (11)$$

$$ll_{n,s}\le ll_n^{hold}\le d_n\quad\forall n\in N,\forall s\in S \quad (12)$$

$$-\Delta p_g^{R.dw.hold}\le\Delta p_{g,s}\le\Delta p_g^{R.up.hold}\qquad\forall g\in G,\forall s\in S \quad (13)$$

$$f_{l,s}^{FACTS}=0\quad\forall l\in L^{FACTS},\ \forall s\in S \quad (14)$$

b) *Stage 2*

(1)–(13) [(14) are ignored]

$$p_g=itrp_{g,s}^{St(1)}\ \forall g,s\in GS^{itrp\_St(1)} \quad (15)$$

$$\Delta p_{g,s}=-itrp_{g,s}^{St(1)}\quad\forall g,s\in GS^{itrp\_St(1)} \quad (16)$$

$$-\left(\frac{X_l^{max}}{X_l^{AC}+X_l^{max}}\right)\cdot f_{l,1}^{AC}\le f_{l,1}^{FACTS}\le-\left(\frac{X_l^{min}}{X_l^{AC}+X_l^{min}}\right)\cdot f_{l,1}^{AC} \quad (17)$$

$\forall l\in L^{FACTS}, f_{l,1}^{AC}\ge 0$ in stage 1

$$-\left(\frac{X_l^{min}}{X_l^{AC}+X_l^{min}}\right)\cdot f_{l,1}^{AC}\le f_{l,1}^{FACTS}\le-\left(\frac{X_l^{max}}{X_l^{AC}+X_l^{max}}\right)\cdot f_{l,1}^{AC} \quad (18)$$

$\forall l\in L^{FACTS}, f_{l,1}^{AC}<0$ in stage 1

$$f_{l,s}^{FACTS}=\alpha_{l,s}\cdot f_{l,1}^{FACTS}\qquad\forall l\in L^{FACTS},\ \forall s\in S\backslash\{s=1\} \quad (19)$$

c) *Stage 3*

(1)–(3), (5)–(13) [(4), (14)–(19) are ignored]

$$p_g = itrp_{g,s}^{St(2)} \quad \forall g, s \in GS^{itrp\_St(2)} \tag{20}$$

$$\Delta p_{g,s} = -itrp_{g,s}^{St(2)} \quad \forall g, s \in GS^{itrp\_St(2)} \tag{21}$$

$$\gamma_g \cdot \underline{p_g} \leq p_g + \Delta p_{g,s} \leq \gamma_g \cdot \overline{p_g} \quad \forall g, s \in \left(GS^{itrp\_St(2)}\right)^c \tag{22}$$

$$f_{l,s}^{FACTS} = -\left(\frac{X_l^{FACTS}}{X_l^{AC}+X_l^{FACTS}}\right) \cdot f_{l,s}^{AC} \quad \forall l \in L^{FACTS}, \forall s \in S \tag{23}$$

In Eqs. (1)–(23), all variables that are free except for $p_g, \Delta p_g^{R.up.hold}, \Delta p_g^{R.dw.hold}$, $ll_{n,s}, ll_n^{hold}$ are positive and γ_g that are binary. Also, corrective control actions can only be used in a limited set of states (subset of S) and these actions are provided by generators and loads that belong to a subset of G and N, respectively. These considerations make the formulation both more realistic and workable.

2) Newton-Raphson Calculation: Once the array of active powers associated with power outputs of all generating units is obtained, we run a Newton-Raphson method to determine the associated reactive powers of generating units as well as the set-points/tap positions of various network components (e.g. SVC, transformers, shunts/filters, etc.). To validate the Newton-Raphson solution, we check a three-fold condition: (i) whether the slack generator production is smaller than a threshold (e.g. 0.01% of total demand), (ii) whether reactive power productions and transfers (and associated apparent powers) are within limits, and (iii) whether active power transfers in major network boundaries match to those obtained from the steady-state DC power flow optimization model. If these conditions are not met, we run again the steady-state DC power flow optimization where:

1) Demand (d_n) is increased to include/update network losses (losses in a line are allocated to its end nodes one half each as additional demand);
2) Power capacities (active) are reduced for those components that need to maintain capacity margins for reactive power.

Note that at the end of this iterative process we obtain a complete AC dispatch solution that maintain network margins for security as well as an array of corrective control measures that are contracted to deal with a large set of credible contingencies.

Although this is a sub-optimal, workable meta-heuristic procedure, we demonstrate in Section III that benefits of corrective control and TAM (for which this model has been proposed) are significantly high. This is promising since our estimate corresponds to a lower bound, conservative calculation of the *value of corrective control and TAM*, which can be increased if more efficient solutions are found.

Next, we will determine whether the static, steady-state solution obtained (together with its associated corrective control measures) is stable against critical outages and whether further post-fault actions in the form of TAM are needed.

B. Slave Module: Transient Stability and TAM Activation

We run a stability analysis on the previous solution for a set of critical outage conditions in order to determine whether system operation is stable along with its associated set of corrective actions suggested by the master SCED module, or whether TAM are needed to stabilize system operation. TAM include very fast responses from set-points of HVDC links and cross-border interconnectors which are activated earlier than the primary generation/demand curtailment actions since the formers rely on power electronics rather than switch openings. If system cannot be stabilized (by using primary corrective control only or a mix of both primary corrective control actions and TAM), Eqs. (24), (25) are sent to the master module, which is run again (where i refers to the i^{th} iteration and index b in sets Ls refers to those AC/DC lines and FACTS devices that belong to boundary b). At this point, it is important to mention that engineering insights and practical experience about the study system are critical to make an adequate selection of set B to ensure an adequate and fast convergence of the solution.

$$-\left(T_b^{i-1} - \Delta T_b\right) \leq T_b^i \leq T_b^{i-1} - \Delta T_b \quad \forall b \in B \tag{24}$$

$$T_b^i = \sum_{l \in L_b^{AC} \setminus L_b^{FACTS}} f_{l,1}^{AC} + \sum_{l \in L_b^{FACTS}} f_{l,1}^{AC} + f_{l,1}^{FACTS} + \sum_{l \in L_b^{DC}} f_{k,1}^{DC} \quad \forall b \in B \tag{25}$$

As TAM are basically transient (automatic) operational measures to deal with stability problems rather than thermal limits and last only for a few seconds until the system is stabilized, these are not optimized (i.e. not obtained from SCED). Note that, from a steady-state perspective, TAM are not needed and only the primary corrective control actions (in the form of increase or decrease in generation and demand) suffice. However, because primary corrective control actions are slower, the system may experience transient instability which could be tackled effectively by fast-acting TAM. The interaction between master and slave modules are described next.

C. Solution Algorithm: Master-Slave Iterations

The complete master-slave algorithm is summarized in Fig. 2 where the following steps are executed:

0) Initialize, $i = 1$.
1) Run SCED stage 1 and determine power flow directions and primary corrective control actions, especially excess of power decrease (beyond minimum stable generation levels). Transform that excess of power decrease into intertripping actions.

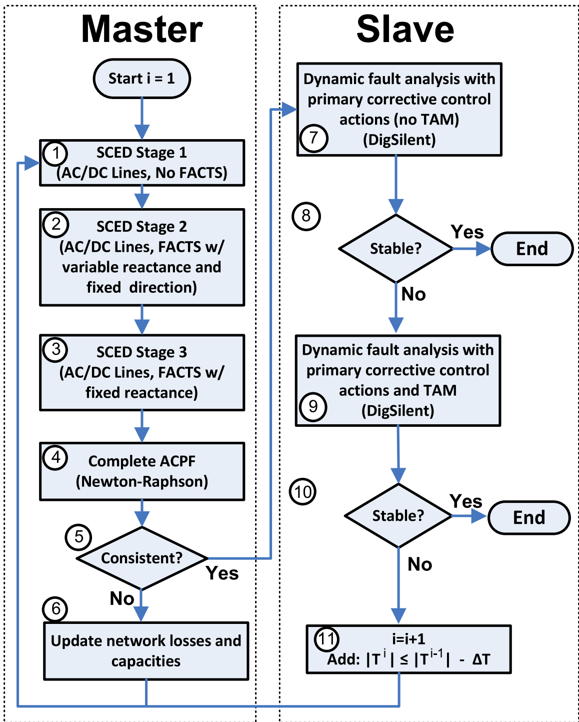

Fig. 2. Steps of master-slave algorithm.

2) Run SCED stage 2 by using power injection representation of FACTS devices (when directions of power transfers are known), and given intertrip actions (from previous step). Determine the power transfer volumes through FACTS devices and determine their reactances.
3) Run SCED stage 3 by using the determined reactances of FACTS devices and given intertrip actions (from previous step), and determine final generation dispatch, setpoint of FACTS devices and HVDC links, and the portfolio of primary corrective control actions in the form of demand and generation intertrip actions.
4) Run complete AC power flow analysis (Newton-Raphson) and obtain reactive power injections and transfers.
5) Determine if AC (from step 4) and DC (from step 3) solutions are consistent (by checking the three-fold condition mentioned in Section II-A.2). If true, go to step 7; otherwise, go to step 6.
6) Update network losses according to the solution obtained in step 4 (losses in a line are allocated to its end nodes—one half each—as additional demand) and network capacities (active power) in case capacity margins for reactive power are needed. Go to step 1.
7) Simulate critical faults and exercise the associated primary corrective control actions.
8) Determine if system is stable. If so, end. Otherwise, go to step 9.
9) Apply prescribed set of TAM on power orders of HVDC links, and cross-border interconnectors.
10) Determine if system is stable. If so, end. Otherwise, go to step 11.
11) Do $i = i + 1$ and add a new set of constraints in SCED that limits power transfers in the key boundaries (e.g. Scotland-England boundary) in iteration i to be lower or equal to that in $i - 1$ minus an arbitrary Δ. Go to 1.

Application of TAM may stabilize the system after a fault occurs despite a high level of power transfer in the pre-fault condition. If TAM are unable to stabilize the system for a given dispatch condition determined by the master problem, a new set of constraints is added to the master problem (Eqs. (24), (25)) so as to, in the next iteration, move away from previous solution and determine a more congested (but stable) system operation, reducing power transfers through key transmission boundaries. This iterative process continues until the point where system operation determined by the master problem is proved stable when TAM are applied. Hence, although TAM are applied in a dynamic simulation that are run after the system operation has been determined, these results are used to modify the searching space of the master problem in the next iteration, reducing its domain in order to make system operation more stable.

Note that the step sequence indicated in Fig. 2 refers to the order in which each step of the algorithm has to be run and how information flows from one step to another; however this gives no information regarding the time sequence of corrective actions and TAM (and this will be specified in Section III-A).

D. Detailed Model of the GB Transmission Network

The transmission network model used in this paper is a detailed dynamic representation of the GB system, developed by Scottish Power Transmission Limited in PowerFactory DIgSILENT.

Great Britain currently has 4 GW of cross-border interconnector capacity: 2 GW to France (IFA), 1 GW to the Netherlands (BritNed), 500 MW to Northern Ireland (Moyle), 500 MW to the Republic of Ireland (East-West). The dynamic GB model has been reinforced with the inclusion of 2 FACTS devices in the form of thyristor controlled series capacitor (TCSC), The Western HVDC link (between Scotland and England regions) and the 4 cross-border HVDC interconnectors depicted in Fig. 3.

The GB transmission network model itself consists of 206 synchronous machines, 1,850 transmission lines, 2850 busbars, 2125 transformers, 180 shunts and 657 loads at various voltage levels up to 400 kV. Static VAr Compensators (SVCs) are installed at various voltage levels across the network to improve the voltage profile of the system. Wind farms (on and offshore) are also present in the network providing circa 12 GW of available capacity. The generators are equipped with excitation system models, governors and power system stabilizers (PSS), all of which are kept in operation.

The existing transmission network connecting England-Scotland regions consists mainly of two double circuit at 400 kV, one on the West side of the country and the other on the East, as shown in Fig. 3. The power flow across the $B6$ boundary carried by two 400 kV double-circuit routes are currently constrained because of stability limits. 6 fixed series capacitors are installed in the Scotland-England interconnectors and the 2 TCSCs provide 35% compensation of the overheads line

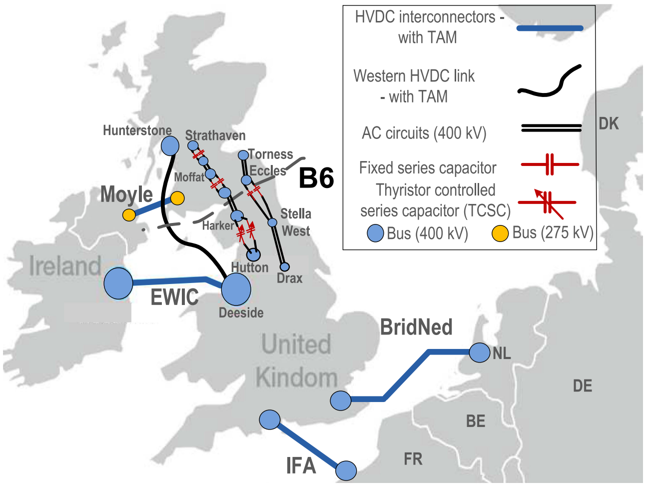

Fig. 3. GB transmission network (2017 scenario) illustrating the key AC circuits reinforced with series compensation interfacing Scotland–England in parallel to the Western HVDC link. The international cross-boarder HVDC interconnectors are also shown.

TABLE I
GENERATION DATA

Name	Available capacity [GVA]	Variable cost Scotland [£/MWh]	Variable cost England [£/MWh]
CCGT	23.0	48	53
CHP	2.5	57	62
Coal	10.3	50	55
Gas	1.7	60	65
Nuclear	12.4	10	15
Wind	12.4	−44	− 39
Hydro/Pump Storage	1.6	2	7
Biomass	0.1	2	7
AGT	6.6	52	57
Total	**70.6**		

reactance installed at the Hutton 400 kV substation in the Harker circuits as shown in Fig. 3. The Western HVDC link which is integrated in parallel to the AC circuits is represented as a bipolar ±600 kV, 2000 MW system with 12-pulse line commutated converters (LCC) at both rectifier and inverter ends [3]. The modelling and characteristics of the Western HVDC link are detailed in [25]. The converters have been configured to provide a short-term (up to 6 hrs) overloading capability of 2.4 GW [3] which enables provisions for rapid modulation of the power order so as to improve transient stability during corrective control.

III. Results and Discussion

A. Input Data and Case Study Description

The 2850-busbar network is assessed along with current conventional generation and wind (on- and offshore) installed capacity levels, and demand backgrounds. In particular, we study network conditions when availability of wind generation is 100% under two demand levels: 57 GW and 35 GW. Data associated with generation capacity available and costs per technology are shown in Table I.

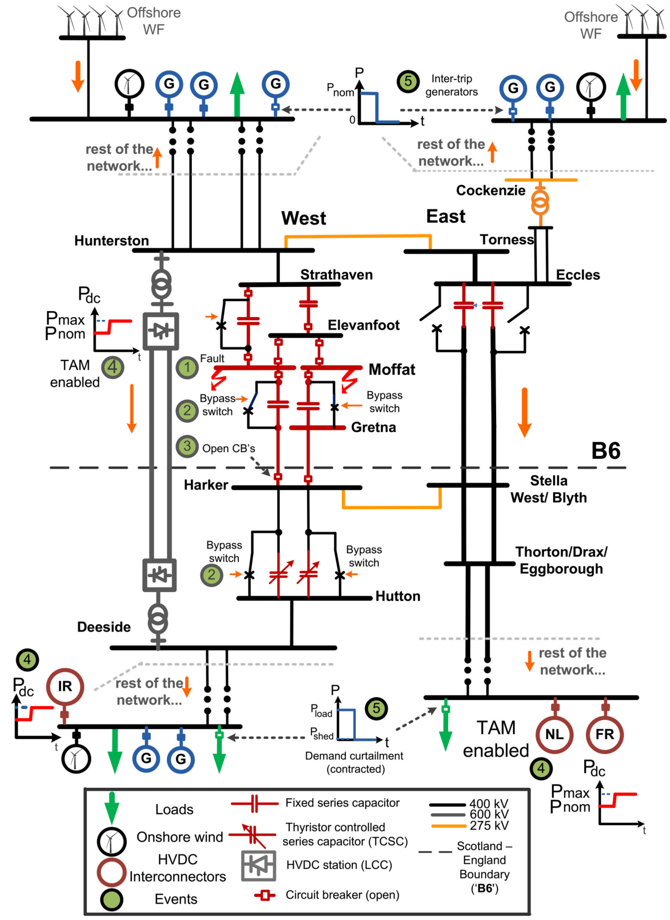

Fig. 4. Detailed single-line diagram of the Scotland-England (B6) boundary. An illustration of the sequence of events that occur starting with (1) fault on Moffat 400 kV substations, which is followed by (2) bypass switch to protect the series capacitors and (3) fault clearance after 4-5 system cycles (through opening circuit breakers). Fault region shown in the red section. This is followed by post-fault corrective control actions including: (4) rapid modulation of the power orders of Western HVDC link and HVDC interconnectors, and finally (5) primary corrective (inter-trip) actions in Scotland and England.

Contract price of demand curtailment is equal to 5 £/MW/h, and the price of generation intertrip is equal to 0.5 £/MW/h. In the steady-state SCED model, we consider 38 double circuit (N−2) outages across 16 major boundaries, including 2 double circuit (N−2) outages in B6 (West and East corridors). We consider that the 4 cross-border interconnectors can provide TAM by assuming a capacity headroom of 5%. Likewise, the Western HVDC link can provide TAM through a 20% capacity headroom [3], [19]. The sequence of events (fault and corrective control actions) simulated and their activation times are shown in Fig. 5. Part of the GB network affected by these actions is illustrated in Fig. 4.

B. Economic Results

Table II shows costs associated with 3 transfer levels in B6 in which Case A resembles current conditions where corrective control is not allowed and thus security is provided by preventive actions only (i.e. network congestion). Although Case A does not incur in costs associated with corrective control

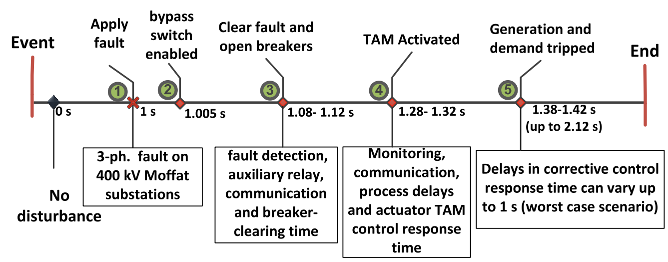

Fig. 5. The sequence of events and their activation times.

TABLE II
ECONOMIC RESULTS (57 GW DEMAND)

	Case A	Case B	Case C
B6 Transfer [GW]	4.4	4.95	5.5
Congestion cost [k£/h]	147	107	104
Corrective control cost [k£/h]	0	3	6
Stability ensured through	Preventive control only	Corrective actions (CA)	CA + TAM

TABLE III
ECONOMIC RESULTS (35 GW DEMAND)

	Case A	Case B	Case C
B6 Transfer [GW]	4.4	4.95	6.0
Congestion cost [k£/h]	241	4.95	122
Corrective control cost [k£/h]	0	3	9
Stability ensured through	Preventive control only	Corrective actions (CA)	CA + TAM

actions (i.e. holding fee associated with generation and demand trips), its congestion cost is significantly higher (congestion cost is the difference in operating cost between the network constrained dispatch and the unconstrained-or merit order-dispatch). In contrast, under Case B, corrective control is allowed and thus network utilization increases in pre-fault condition provided that if an $N-2$ fault occurs, post-fault congestions can be eliminated by using corrective actions (550 MW of generation/demand curtailment in Scotland/England). In Case B, network operation becomes more economically efficient since the increase in corrective control costs is lower than the increase in network congestion cost savings. Furthermore, Table II shows that higher transfers can be allowed in $B6$ (up to 5.5 GW, which increases the economic efficiency of network operation) if a set of technically effective TAM is deployed (Case C). In Case C, primary corrective control actions (1.1 GW of generation/demand curtailment in Scotland/England) are complemented by TAM composed by power order changes of 400 MW in the Western HVDC and a total change of 200 MW in the cross-border interconnectors.

Benefits of corrective control and TAM increases in conditions with lower demand levels since more wind generation from Scotland needs to be transferred to load centers in England. This is shown in Table III where increased power transfers drive significantly higher savings in congestion cost than those shown in Table II (demand in both Scotland and England are

TABLE IV
TCSC COMPENSATION AND ASSOCIATED COST SAVINGS AT DIFFERENT TRANSFER LEVELS (35 GW DEMAND)

Transfer level (security mode) [GW]	TCSC compensation [%]	Operational cost saving due to TCSC optimization [%]
4.4 (preventive security)	−35 (capacitive)	2.5
6.0 (corrective security)	+35 (inductive)	1.5

reduced in Table II while generation in England–rather than Scotland–is also reduced as a result of an optimal dispatch; Scotland-England system can be seen as a two-area system with dominant transfers mainly due to wind power from Scotland to England). Corrective control costs are driven by the need to hold generation and demand capacity to carry out inter-tripping actions in case a double network outage occurs. When demand is minimum (as shown in Table III), power from Scotland to England can be transferred up to 6 GW through $B6$, provided that sufficient corrective control actions are held in order to deal with an $N-2$ network outage (1.6 GW of generation/demand curtailment in Scotland/England), supported by TAM (changes in power orders of 400 MW in the Western HVDC and a total change of 200 MW in the cross-border interconnectors).

Interestingly, the transmission network is severely congested when demand is 35 GW which increases the benefits of TCSC set-point optimization for congestion management. In fact, when demand is 35 GW, TCSC optimization can reduce operational cost by 2.5% (with respect to the case without TCSC) making the congestion management activity more efficient and this is shown in Table IV.

C. Stability Analysis

The dynamic behavior of the GB system in response to a double-circuit line outage (as depicted in the red sections of Fig. 4) on the transient stability of the GB system is studied. Four dynamic studies are illustrated in Figs. 6–9 reflecting Case A, B, C as described in Tables II, III.

Fig. 6 shows (under Case A) the tie-line transfers between Scotland-England regions and the manner in which the generator rotor angles evolve immediately after the double-circuit fault occurs. We can conclude that:

1) At 4.4 GW transfer the system is transiently stable.
2) Beyond 4.4 GW it is clear from Fig. 6(c) that generator units in Scotland *loses synchronism with respect to England/Wales and becomes monotonically unstable*.

The 4.4 GW limit for the GB system is based on *preventive control*, that is, the system is stable for credible contingencies such as a double-circuit outage without the need for corrective, post-contingency actions.

Fig. 7 looks at the opportunity to raise the pre-fault transfer limit by further 550 MW using appropriate *corrective control actions only* (Case B). The system performance are shown in 7(a)–(b) whilst the corrective control (generator/demand curtailment) actions that take place in 7(c).

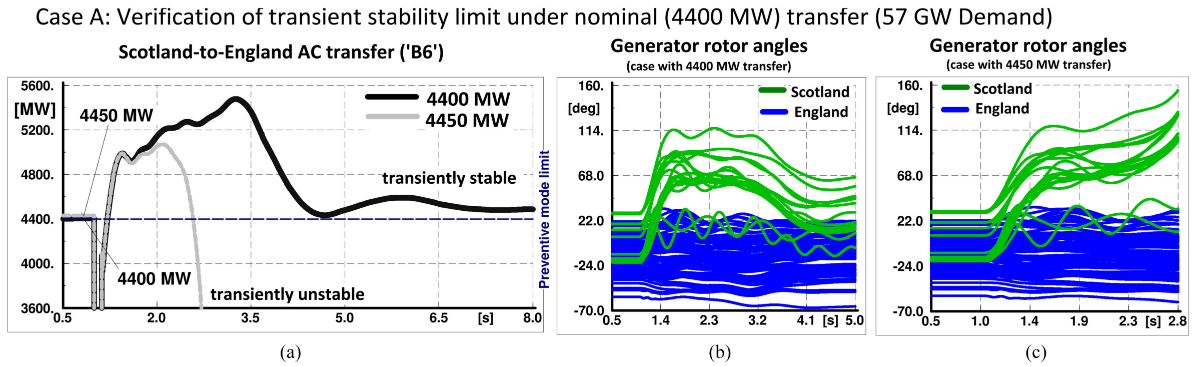

Fig. 6. Dynamic response of the system in *preventive mode* (without considering post-fault actions) in response to the double-circuit outage fault. The fault location is shown in Fig. 4 and the activation times in Fig. 5. Variables plotted are denoted above each subplot.

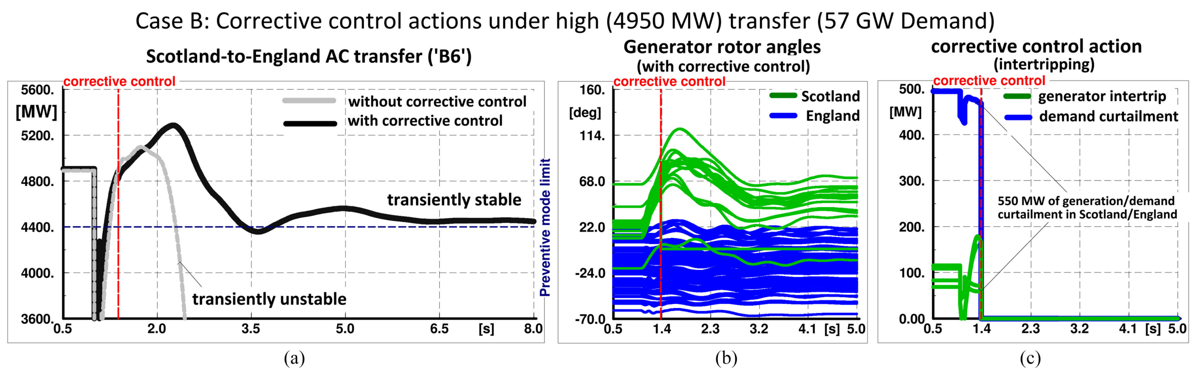

Fig. 7. Dynamic response of the system *with corrective mode* only (without considering post-fault TAM control actions) in response to double-circuit outage.

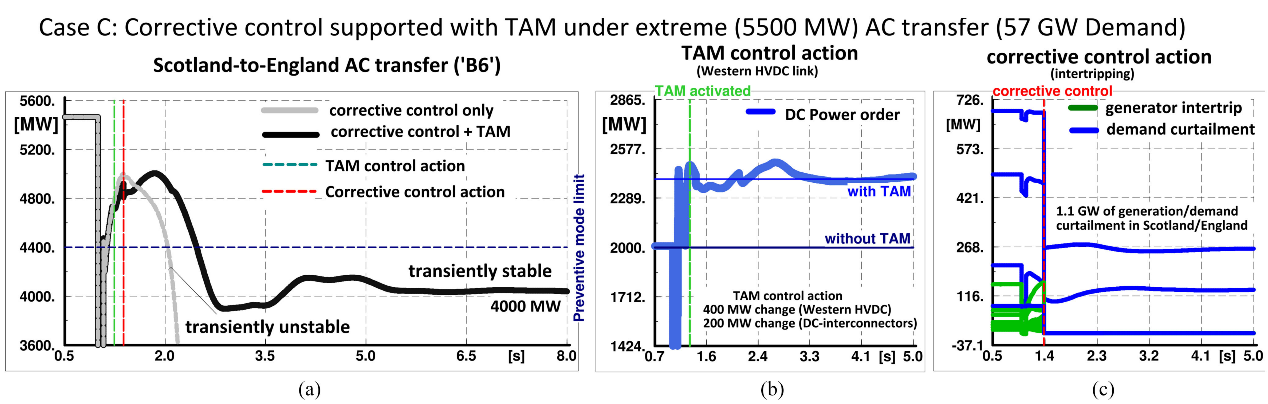

Fig. 8. Dynamic response of the system *with corrective control supported by TAM* (under 57 GW demand) in response to double-circuit outage fault.

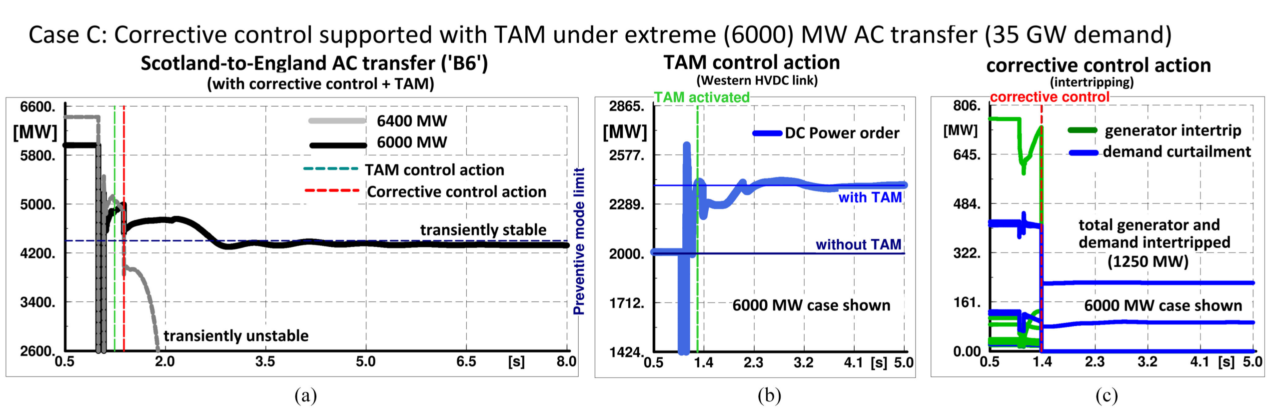

Fig. 9. Dynamic response of the system *with corrective control supported by TAM* (under 35 GW demand) in response to double-circuit outage fault.

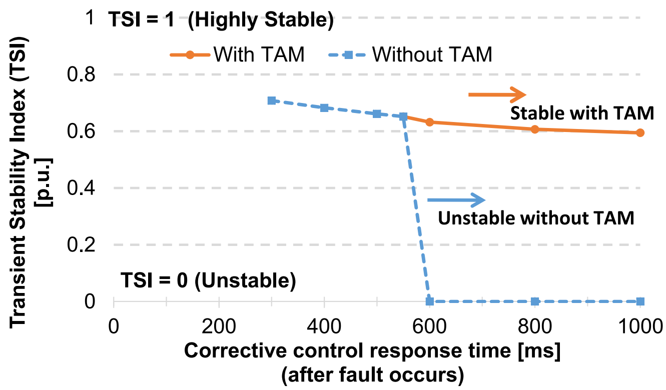

Fig. 10. Transient Stability Index (TSI) [26] as a function of corrective control response time with and without TAM (case B under 57 GW demand).

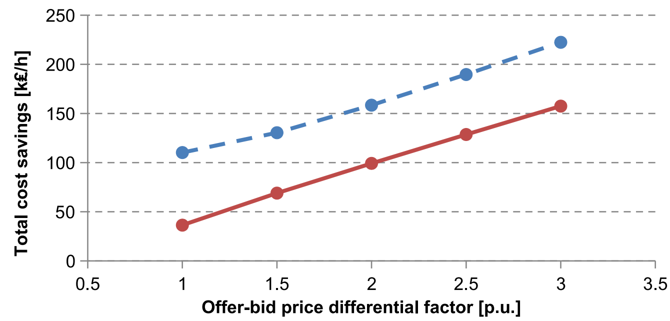

Fig. 11. Benefits of corrective control mode plus TAM when price of congestion increases (generator's bid price = generator's variable cost divided by k, generators offer price = generator's variable cost multiplied by k; $k = 1$ corresponds to the cost reflective case and $k = 2$ is the value typically used in GB for market analysis; in this figure k ranges from 1 to 3). Solid red trace refers to 57 GW Demand; dashed blue trace refers to 35 GW Demand.

Figs. 8 and 9 examine the effectiveness of using *corrective control supported by TAM* under extreme transfer conditions (see Case C in Tables II, III). Here, subplots (a) shows the Scotland-to-England AC transfer whilst (b)–(c) show the TAM and corrective control actions required to ensure a stable post-fault response. For the 35 GW and 57 GW Demand cases, we can securely transfer 1.6 GW and 1.1 GW, respectively, above the preventive mode limit.

For transient stability it is not necessarily adequate to use a larger amount of corrective control action (generator inter-trip and demand curtailment) according to the intended increase in pre-fault power transfer levels. This is due to the relatively slow response time of corrective control in comparison to the larger rate of power angle separation for higher power transfer conditions. TAM with much faster response time and higher controllability (as TAM is exercised at transmission level and through power electronics) can complement the corrective control actions to ensure transient stability under such high pre-fault power transfers (as in Case C).

D. Speed Requirements for ICT Infrastructure

Application of advance corrective control actions and TAM to release latent network capacity will require fast response times and increased reliability levels associated with information and communications technology (ICT) infrastructure. In effect, latencies and delays related to monitoring, communication, processing and actuation activities could significantly jeopardize power system security and stability. In this context, We employ a transient stability index (TSI), reported in the literature [26], which measures the relative rotor angle separation between the generators in the system following a fault in the network. This is used as a stability indicator that evaluates the severity of a contingency (TSI value: 1—highly stable; 0—unstable). Fig. 10 shows how the system stability is degraded when response times of primary corrective control actions are delayed, and demonstrates that TAM can be an effective measure to minimize impacts of such communication delays on stability and thus on security of supply.

In particular, Fig. 10 illustrates that transfer levels that can be secured through primary corrective control actions only (without TAM), are more robust against delays in corrective control actions when TAM are deployed. Hence, primary corrective control can permanently be accompanied by TAM as a hedge against ICT malfunctions and thus decrease risk of instability when transferring power beyond 4.4 GW through $B6$.

E. Market Prices Sensitivity

Benefits of corrective control and TAM (that can be calculated as the cost difference between case C and A under each demand condition and associated costs can be observed in Tables II and III) can be increased if contract prices associated with intertripping demand and generation through SPS decrease, or if the price to constrain system operation becomes higher (note that congestion costs have been previously calculated by assuming that network congestion is balanced through cost-reflective bids and offers — bids and offers are changes in power outputs with respect to the merit order dispatch position and serve to accommodate network congestion—which is clearly a conservative estimation). In this context, Fig. 11 illustrates how benefits of corrective control and TAM increase when bids (and offers) in the balancing markets are less cost reflective (which increases the unit cost of congestion).

F. Comments on the Computational and Optimality Performance of the SCED Model

We compared the optimal solutions in various operating conditions against those obtained by our 3-stage SCED. For the analyzed GB case (which was reduced to its 29-busbar version to be able to find the optimal solution -by using a fully coupled model rather than a 3-stage model- in reasonable timescales), we found that our method could reach the optimal solution due to the three following reasons:

1) Generation intertrips (following a line failure) can hardly be avoided by using FACTS devices (this is especially true when there is no re-optimization of their setpoints between pre- and post-fault conditions)
2) FACTS device can hardly produce an impact on the direction of its line's pre-fault transfer (with respect to the condition without FACTS and this is especially true when

the device is installed in a major transmission corridor such as the England-Scotland interconnector)

3) The ratio between the pre- and post- fault power flows of a line is practically insensitive to slight changes to its reactance due to installation of series compensation (this can be algebraically demonstrated since the ratio between the pre- and post- fault PTDFs of a line is practically insensitive to slight changes in its reactance and we leave this exercise to the reader)

Evidently, the improved performance of our method in this case is due to the special topology conditions of the GB system and this cannot be guaranteed for any network topology. Also, our 3-stage SCED is approximately 5 times faster than its fully coupled, optimal version.

IV. Conclusion And Further Work

A novel sequential approach to quantify the efficacy and value of using corrective control supported by TAM is proposed based on (i) a master SCED module that determines optimal dispatch solutions and a set of primary corrective actions (over generation and demand) for possible contingencies (optimizing pre- and post-fault control actions according to market prices), and (ii) a slave module that activates the appropriate TAM to ensure system stability for the dispatch condition set by the master module (set of TAM includes rapid changes in set-points of the Western HVDC link between Scotland and England areas and changes in set-points of 4 international interconnectors between GB and Ireland $(\times 2)$, France and the Netherlands). The proposed approach is tractable and demonstrated to solve very large-scale dispatch problems over a realistic representation of the GB system used by transmission system owners. To do so, we eliminated the need to define a larger set of binary variables (those associated with FACTS/HVDC–expanding on [23]–and generation tripping) and the need to use non-linear optimization models by decoupling key decisions in various stages.

We demonstrated that corrective control actions based on generation and demand response when supported by coordinated control of the Western HVDC link and international interconnectors, is shown to be highly effectively to improve system stability and thereby, increase the allowable (pre-fault) power transfers through the England–Scotland interconnectors whilst maintaining N-2 security. Without the proposed coordinated TAM, the benefit of generation and demand response is compromised and the risk of transient instability is significantly higher. The benefit of corrective control actions accompanied by TAM are estimated to be between 37 k£ and 110 k£ in a congested hour depending on demand levels (at maximum wind output), which can be significantly increased if bid and offer prices in GB market are not cost-reflective (which is usually the case).

Although the use of increased corrective control actions will require faster responses and higher reliability levels from the ICT infrastructure, we demonstrated that TAM could be an effective measure to minimize the risk of instability when primary corrective control is delayed due to potential problems in the ICT infrastructure. Hence, primary corrective control can be permanently accompanied by TAM as a hedge against ICT malfunctions, and thus decrease risk of instability when transferring power beyond 4.4 GW through $B6$.

To fully unlock the benefits of corrective control and TAM determined in this paper, one of the initiatives that need to be undertaken in the near future is the elaboration of an online computational tool. In this context, concepts developed in the field of Dynamic Security Assessment (DSA) like those in references [5], [27]–[29], [30] could be successfully applied to the problem analyzed in this paper. In particular, algebraization of differential equations, and application of severity indices, artificial intelligence, neural network, advanced statistical techniques and decision trees to determine security/stability boundaries and the portfolio of preventive and corrective measures, look promising to coordinate various pre- and post-fault decision of both generation dispatch and setpoints of network devices. Some of these concepts (e.g. algebraization of differential equations, severity indices) can also be used to generalize our offline model and replace Eqs. (24)–(25) for a more general mathematical expression that can be used beyond the GB system.

References

[1] "National Grid electricity ten year statement," 2016. [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-Ten-Year-Statement/
[2] "NETS security and quality of supply standard." 2014. [Online]. Available: http://www2.nationalgrid.com/uk/industry-information/electricity-codes/sqss/the-sqss/
[3] S. Achenbach, V. Barry, C. H. Bayfield, and P. F. Coventry, "Increasing the gb electricity transmission networks power transfer capability between north and south–the western hvdc link," in *Proc. 10th IET Int. Conf. AC DC Power Trans.*, Dec. 2012, pp. 1–4.
[4] E. De Tuglie, M. Dicorato, M. La Scala, and P. Scarpellini, "A corrective control for angle and voltage stability enhancement on the transient time-scale," *IEEE Trans. Power Syst.*, vol. 15, no. 4, pp. 1345–1353, Nov. 2000.
[5] I. Genc, R. Diao, V. Vittal, S. Kolluri, and S. Mandal, "Decision tree-based preventive and corrective control applications for dynamic security enhancement in power systems," *IEEE Trans. Power Syst.*, vol. 25, no. 3, pp. 1611–1619, Aug. 2010.
[6] S. Chatzivasileiadis and G. Andersson, "Security constrained opf incorporating corrective control of hvdc," in *Proc. IEEE Power Syst. Comput. Conf.*, 2014, pp. 1–8.
[7] I. Martinez Sanz, B. Chaudhuri, G. Strbac, K. Hussain, C. Bayfield, and R. Adapa, "Corrective control through western hvdc link in future great britain transmission system," in *Proc. IEEE Power Energy Soc. Gen. Meet.*, 2015, pp. 1–5.
[8] P. McNamara, R. R. Negenborn, B. De Schutter, and G. Lightbody, "Optimal coordination of a multiple hvdc link system using centralized and distributed control," *IEEE Trans. Control Syst. Technol.*, vol. 21, no. 2, pp. 302–314, Mar. 2013.
[9] Y. Phulpin, J. Hazra, and D. Ernst, "Model predictive control of HVDC power flow to improve transient stability in power systems," in *Proc. IEEE Int. Conf. Smart Grid Commun.*, 2011, pp. 593–598.
[10] P. Shi, Y. Wen, Z. Yan, J. Qian, M. Deng, and C. Guo, "Risk-based security assessment considering corrective control of TCSC devices," in *Proc. IEEE Int. Conf. Power Syst. Technol.*, 2014, pp. 1834–1840.
[11] S. Bruno, E. De Tuglie, M. La Scala, and P. Scarpellini, "Dynamic security corrective control by UPFCs," *IEEE Power Eng. Rev.*, vol. 21, no. 8, Aug. 2001, Art. no. 58.
[12] M. A. Bucher and G. Andersson, "Robust corrective control measures in power systems with dynamic line rating," *IEEE Trans. Power Syst.*, vol. 31, no. 3, pp. 2034–2043, May 2014.
[13] J. W. Stahlhut, T. J. Browne, G. T. Heydt, and V. Vittal, "Latency viewed as a stochastic process and its impact on wide area power system control signals," *IEEE Trans. Power Syst.*, vol. 23, no. 1, pp. 84–91, Feb. 2008.
[14] G. C. Zweigle and V. Venkatasubramanian, "Wide-area optimal control of electric power systems with application to transient stability for higher order contingencies," *IEEE Trans. Power Syst.*, vol. 28, no. 3, pp. 2313–2320, Aug. 2013.

[15] J. Ford, G. Ledwich, and Z. Y. Dong, "Efficient and robust model predictive control for first swing transient stability of power systems using flexible ac transmission systems devices," *IET Gener., Trans. Distrib.*, vol. 2, no. 5, pp. 731–742, Sep. 2008.

[16] A. Bonfiglio *et al.*, "Improving power grids transient stability via model predictive control," in *Proc. Power Syst. Comput. Conf.*, 2014, pp. 1–7.

[17] A. Fuchs, S. Mariethoz, M. Larsson, and M. Morari, "Grid stabilization through VSC-HVDC using wide area measurements," in *Proc. IEEE Trondheim PowerTech.*, 2011, pp. 1–6.

[18] A. Fuchs, M. Imhof, T. Demiray, and M. Morari, "Stabilization of large power systems using VSC–HVDC and model predictive control," *IEEE Trans. Power Del.*, vol. 29, no. 1, pp. 480–488, Feb. 2014.

[19] Y. Pipelzadeh, R. Moreno, B. Chaudhuri, G. Strbac, and T. C. Green, "An assessment of transient assistive measures using HVDC for special protection schemes: Case on the GB transmission system," in *Proc. 10th IET Int. Conf. AC DC Power Trans.*, 2012, pp. 1–6.

[20] Y. Pipelzadeh, R. Moreno, B. Chaudhuri, G. Strbac, and T. C. Green, "Role of smart grid technology and corrective control in enhancing network capacity utilisation in great britain with HVDC links," in *Proc. CIGRE Symp. HVDC Syst. Markets Integr. Lund, Sweden*, 2015, pp. 1–14.

[21] R. Moreno, D. Pudjianto, and G. Strbac, "Transmission network investment with probabilistic security and corrective control," *IEEE Trans. Power Syst.*, vol. 28, no. 4, pp. 3935–3944, Nov. 2013.

[22] I. Martinez Sanz, B. Chaudhuri, and G. Strbac, "Corrective control through hvdc links: A case study on gb equivalent system," in *Proc. IEEE Power Energy Soc. Gen. Meet.*, 2013, pp. 1–5.

[23] M. Sahraei-Ardakani and K. W. Hedman, "A fast LP approach for enhanced utilization of variable impedance based FACTS devices," *IEEE Trans. Power Syst.*, vol. 31, no. 3, pp. 2204–2213, May 2016.

[24] G. Blanco, F. Olsina, F. Garcés, and C. Rehtanz, "Real option valuation of FACTS investments based on the least square Monte Carlo method," *IEEE Trans. Power Syst.*, vol. 26, no. 3, pp. 1389–1398, Aug. 2011.

[25] Y. Pipelzadeh, B. Chaudhuri, and T. C. Green, "Role of western HVDC link in stability of future great britain (GB) transmission system," in *Proc. IEEE Power Energy Soc. Gen. Meet.*, Jul. 2015, pp. 1–5.

[26] D. Gautam, V. Vittal, and T. Harbour, "Impact of increased penetration of DFIG-based wind turbine generators on transient and small signal stability of power systems," *IEEE Trans. Power Syst.*, vol. 24, no. 3, pp. 1426–1434, Aug. 2009.

[27] V. J. Gutierrez-Martinez, C. A. Cañizares, C. R. Fuerte-Esquivel, A. Pizano-Martinez, and X. Gu, "Neural-network security-boundary constrained optimal power flow," *IEEE Trans. Power Syst.*, vol. 26, no. 1, pp. 63–72, Feb. 2011.

[28] E. M. Voumvoulakis and N. D. Hatziargyriou, "A particle swarm optimization method for power system dynamic security control," *IEEE Trans. Power Syst.*, vol. 25, no. 2, pp. 1032–1041, May 2010.

[29] C. Liu *et al.*, "A systematic approach for dynamic security assessment and the corresponding preventive control scheme based on decision trees," *IEEE Trans. Power Syst.*, vol. 29, no. 2, pp. 717–730, Mar. 2014.

[30] G. Hou and V. Vittal, "Cluster computing-based trajectory sensitivity analysis application to the WECC system," *IEEE Trans. Power Syst.*, vol. 27, no. 1, pp. 502–509, Feb. 2012.

Yousef Pipelzadeh (S'09–M'12) received the Ph.D. degree in power systems from Imperial College London, London, U.K., in 2012. He is currently a Research Associate at Imperial College London, and the Business Development Manager of Manitoba HVDC Research Center in the UK. He is recognized by the British Standard Institute as a UK Principle Expert, and is an Active Member on the European Commission (Cenelec working group TC8X/WG 06) developing the guidelines and standards on HVDC Grids. He is an active member of the IET and CIGRÉ. His research interests include power system dynamics and offshore DC networks.

Rodrigo Moreno (M'05) received the B.Sc. and M.Sc. degrees from Pontificia Universidad Catlica de Chile, Santiago, Chile, and the Ph.D. degree from Imperial College London, UK. He is currently an Assistant Professor at the University of Chile and a Research Associate at Imperial College London. His research interests include power system optimization, reliability and economics, renewable energy, and the smart grid.

Balarko Chaudhuri (M'06–SM'11) received the Ph.D. degree in electrical and electronic engineering from Imperial College London, London, U.K., in 2005. His research interests include power systems stability, grid integration of renewables, HVDC, FACTS, demand response and smart grids. He is an associate editor of the IEEE Systems Journal and Control Engineering Practice. He is a Fellow of the IET and a Member of CIGRÉ.

Goran Strbac (M'95) is currently a Professor of energy systems at Imperial College London, London, U.K. His current research interests include modeling and optimization of economics and security of energy system operation and investment including integration of emerging technologies in supporting cost effective evolution to smart low carbon energy future.

Tim C. Green (M'89–SM'02) received the B.Sc. (Eng) (first class hons.) degree from Imperial College London, London, U.K., in 1986, and the Ph.D. degree from Heriot-Watt University, Edinburgh, U.K., in 1990. He is currently a Professor of electrical power engineering at Imperial College London, and the Director of the Energy Futures Lab. His research interest includes formulating the future form of the electricity network to support low-carbon futures. A particular theme is how the flexibility of power electronics and control can be used to accommodate new generation patterns and new forms of load, such as EV charging, as part of the emerging smart grid. He has particular interests in offshore DC networks and of management of low voltage networks.