A Decision Support Tool for Transient Stability Preventive Control

Pertl, Michael; Weckesser, Johannes Tilman Gabriel; Rezkalla, Michel M.N.; Heussen, Kai; Marinelli, Mattia

Published in:
Electric Power Systems Research

Link to article, DOI:
10.1016/j.epsr.2017.02.020

Publication date:
2017

Document Version
Early version, also known as pre-print

A Decision Support Tool for Transient Stability Preventive Control

Michael Pertl[a], Tilman Weckesser[b],
Michel Rezkalla[a], Kai Heussen[a], Mattia Marinelli[a,*]

[a]Center for Electric Power and Energy, Department of Electrical Engineering,
Technical University of Denmark
Frederiksborgvej 399, Building 776, 4000 Roskilde, Denmark
[b]Department of Electrical Engineering and Computer Science at the University of Liège, Belgium

Abstract

The paper presents a decision support tool for transient stability preventive control contributing to increased situation awareness of control room operators by providing additional information about the state of the power system in terms of transient stability. A time-domain approach is used to assess the transient stability for potentially critical faults. Potential critical fault locations are identified by a critical bus screening through analysis of pre-disturbance steady-state conditions. The identified buses are subject to a fast critical contingency screening determining the actual critical contingencies/buses. These two screenings aim at reducing the computational burden of the assessment, since only contingencies considered as critical are taken into account. The critical clearing times for the critical contingencies are determined. A preventive re-dispatch of generators to ensure a predefined minimum critical clearing time for faults at all buses is proposed, while costs are minimized. The results of the assessment are presented to the control room operator, who decides to accept the suggested dispatch or to repeat the assessment considering additional user-specific constraints. The effectiveness of the proposed method is demonstrated on a standard nine-bus and the New England test system.

Keywords: Control Room Operator, Decision Support, Online Assessment, Preventive Control, Situation Awareness, Transient Stability

*Corresponding author
Email address: matm@elektro.dtu.dk (Mattia Marinelli)

1. Introduction

Observability of power systems has to be increased to improve the situation awareness of control room operators. Situation awareness is a key aspect in maintaining power system security, because it enables anticipation of critical conditions and effectively set preventive actions to mitigate them [1, 2]. Lack of situation awareness was several times identified as one of the major causes for large power system blackouts [3, 4]. Various problems with situation awareness are related to missing information, i.e. the control room operator is not provided with the needed information [5–7]. Therefore, appropriate monitoring, visualization and decision support tools have to be developed to support the decision making process and to prevent or properly respond to electrical incidents in order to maintain power system stability [8, 9]. Dedicated decision support tools are needed to facilitate the incorporation of high shares of renewable energy sources (RES) while keeping the power system operative and stable [10]. However, in this work, RES are not included in the analysis intentionally, as the work is mainly concerned with improving the calculation methods for a required re-dispatch. Since a considerable amount of the RES are converter driven (e.g., photovoltaic and wind turbines), they cannot lose synchronism as they are usually synchronized to the grid by a phase-locked loop. Moreover, due to advanced capabilities, such as voltage support during fault-ride-through situations, RES can contribute positively to maintain transient stability.

Transient stability is an important aspect of power system stability since it describes the ability of a power system to withstand large disturbances and keep synchronism [11]. Maintaining synchronism means that all synchronous generators (SGs) in a system operate at the same rotor speed and none of them falls out-of-step by accelerating or decelerating with respect to the other SGs. Transient instability can lead to widespread outages due to unintended tripping of protection devices which could trigger a cascaded breakdown of the power system [12]. Hence, it is crucial to assess the transient stability of power systems online on a grid-wide basis and set preventive actions if issues are identified [13, 14].

The paper presents a novel online decision support tool for transient stability preventive control, building on experiences of previous tools. The proposed tool takes into account the current grid state and analyzes the grid's capability to withstand three-phase faults for a user-specified duration (desired limit, minimum critical clearing time (CCT), further called CCT_{lim}) at the most severe locations (buses) of the grid. A time-domain (TD) approach is used to assess transient stability on a grid-wide basis. To reduce the computational burden of the TD simulations, a critical bus screening (CBS) and fast critical contingency screening

(FCCS) are carried out prior to the assessment. The CBS identifies potentially critical buses with regard to three-phase faults, by means of pre-disturbance conditions without the need for TD simulations. The FCCS determines the actual critical buses within the set of potentially critical buses by checking whether the system can withstand a three-phase fault for user-specified limit without any SG losing synchronism. This results in a yes/no decision, which eventually determines the critical buses. To achieve the desired minimum CCT for all critical buses, the needed dispatch of SGs is determined. The power is dispatched by means of an optimal power flow (OPF) calculation minimizing the generation costs while respecting technical constraints, such as generators' capacity, maximum line flows and bus voltage limits. Since the method aims at proposing a preventive generation re-dispatch, which ensures that the stability margins in the current operating point are sufficient, the ramp rates of generators are not considered in the OPF. As the preventive control is applied before a contingency occurs, the consideration of costs is an important factor in the assessment. The results of the assessment in terms of needed re-dispatch and associated costs are presented to the control room operator who has to decide whether the proposed re-dispatch is applied or not. The operator may also introduce additional constraints, e.g. the unavailability of generators to take over the dispatched power. The dispatch procedure is re-run, takes into account the additional introduced constraints and delivers a new dispatch proposal. The approach guarantees a minimum CCT for all buses of the power system and, thus, a sufficient transient stability margin.

The main scientific contribution of the paper is twofold. Firstly, a novel fast converging technique to determine the needed dispatch for re-establishing a predefined stability level is presented. Secondly, the paper elaborates on the combination of the transient stability assessment, the dispatch determination and the critical contingency analysis to enable an online application of the approach.

2. Transient Stability Preventive Control - Brief Summary and Relation to the Paper

This section intends to summarize preventive transient stability approaches found in the literature. Moreover, the relation between transient stability assessment and OPF calculation are discussed as both items appear in this work. At this point, only re-dispatch of SGs is discussed as a possible counteraction, whereas many other actions can be applied to enhance transient stability, e.g. load shedding, increase of bus voltage and transmission impedance reduction.

Numerous approaches to determine the needed dispatch can be found in the literature. They can be classified into two categories: a) determining the dispatch within the multi-machine system and b) converting the multi-machine system in a single-machine equivalent (SIME) and analyzing it as an one-machine against infinite bus (OMIB) system.

Regarding the first category, several approaches have been introduced. An approach which uses the virtually linear relationship between rotor angle and CCT of the SGs is proposed in [15, 16]. Since the relationship is not exactly linear, several TD simulations are necessary to obtain accurate results. Moreover, the estimation of the rotor angles introduces additional uncertainties. In [17], the authors propose to use the almost linear relationship between CCT and active power output of the generator. Several TD simulations are needed to determine the relationship. Specifically, seven CCTs associated with the SG power output were calculated in the paper, which implies a high computational burden.

Transient stability analysis using SIME, where the system is transformed into an OMIB equivalent, is very well covered in the literature [18–24]. The SIME approach transforms a multi-machine system to an OMIB equivalent, based on the fact that a loss of synchronism originates from the separation of one machine against another machine (or groups of machines). Considering that, the machines are separated into two groups: the non-critical and the critical machines which are responsible for the loss of synchronism. After the transformation into an OMIB system, transient stability is assessed by using the equal area criterion (EAC). The SIME parameters have to be updated continuously in every time step in order to achieve accurate results while the source for the parameters is provided by a simultaneously running TD simulation.

Regardless of which approach is used to determine the dispatch, power has to be redistributed between the SGs. In order to do that in a transparent and appropriate way, OPF calculations are used to find a good trade-off between security and economics.

In general, transient stability-constrained OPF can be grouped into two different approaches, called *Global Approach* and *Sequential Approach*. The authors of [18] propose the mentioned grouping and give a comprehensive and up-to-date summary about transient stability in OPF calculations and about real-time stability in power systems in general. In the global approach [22, 25–28], transient stability models are converted into algebraic equations at each time step of the simulation. This non-linear set of equations is then included in the OPF as a stability constraint, which results generally in a large single non-linear programming problem. In the sequential approach, transient stability constraints are derived from TD simulations and directly converted into conventional constraints of standard OPF calculations, e.g. maximum active power setpoints of the generators. The advantages of the sequential approach are that the OPF can be solved with a standard OPF solver and the flexibility of choice of the receiving generators for the dispatch. Opposed to these advantages, however, the sequential approach does not guarantee optimality which, therefore, makes the global approach more appealing from a conceptual perspective [18].

Since this paper aims at providing a tool for transient stability preventive control from the operator's perspective, the problem is seen from a different angle. The tool should inform the operator about insufficient transient stability margins and support the operator's decision making by suggesting an appropriate dispatch to achieve the defined stability margin. An interesting transient stability assessment approach for preventive control, that incorporates the critical contingency filtering and ranking method from [29], was proposed in [19, 24]. A sequential approach, based on SIME, has been developed in the mentioned work. Opposed to that, the approach proposed in this manuscript takes into account the full multi-machine system without the need to transform it into an OMIB system. Moreover, in the proposed approach only 2-3 CCTs need to be calculated to determine the dispatch of a generator.

3. Description of the Transient Stability Preventive Control Approach

In emergency control, the incident already occurred and the main aim is to safe the system. Opposed to that, the objective of preventive control is to prepare the power system for future uncertain events which may occur. The system has to be operated and maintained in a state, where it is able to withstand and handle disturbances satisfactorily. Therefore, in preventive control economic aspects have to be taken into account. The system operator would usually refuse to take expensive countermeasures against contingencies that may occur [30] and, thus, a trade-off solution between costs and security has to be found.

The proposed approach for transient stability preventive control utilizes TD simulations, which consider the full dynamics of the power system to calculate the minimal power to be dispatched from the critical machines to non-critical machines in order to re-establish a predefined stability margin in terms of CCT. Since TD simulations require high computational power and the method aims at supporting control room operators in taking their decisions, a CBS is carried out prior to the assessment. As the economic aspect for preventive dispatch is of crucial importance, consecutive OPFs are carried out to minimize generation costs while respecting the technical constraints. That approach enables to derive the best trade-off solution to support the control room operator in its decision making. Moreover, the specified stability limit (minimum CCT) is satisfied and secure operation in terms of transient stability is guaranteed. In this work, the minimum desired CCT (CCT_{lim}) is assumed to be $200\,ms$. That is a reasonable limit, since it can be assumed that the protection equipment will detect and clear the fault by opening the breakers within this time span [31]. The flow chart of the proposed transient stability preventive control approach is shown in Fig. 1. It comprises the elements which are needed to establish a transient stability control and visualizes how they interact. In the following section, all elements are comprehensively described.

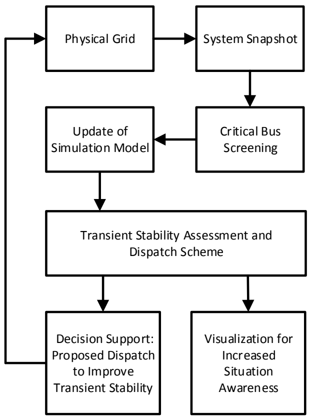


Figure 1: Flow chart of the transient stability preventive control approach

3.1. Physical Grid

This block represents the real physical grid, for which the transient stability control is applied. The feedback from the decision support block represents the interaction of the control room operator with the physical grid. The control room operator has to decide and approve whether the proposed dispatch is applied to the system or additional constraints are to be considered in the assessment leading to a new dispatch recommendation.

3.2. System Snapshot

A system snapshot is needed to update the TD simulation model with the current system state. Two variants are proposed to obtain a system snapshot. In the first variant, the needed data is extracted from the SCADA system. The needed data includes: breaker status, generation output, activation of capacitor banks, RES generation, line flows and further relevant data. Phasor measurement units (PMUs) are another option to obtain a system snapshot, but that assumes full observability of the power system by PMUs. In case, the needed data is not fully available from either of these sources, a hybrid approach could be used by combining SCADA and PMU data to obtain a full system snapshot [32].

3.3. Critical Bus Screening (CBS)

Based on the current system snapshot, a CBS, which aims at determining the most critical fault locations, is carried out prior to the update of the simulation model. Here, the focus is on assessing bus bar faults. Therefore, in the following the term critical buses is used, instead of the more generic term critical fault location. The CBS analyzes the pre-disturbance conditions and filters out the potentially critical buses with regard to three-phase faults. No TD simulations are needed for the CBS, hence, the needed computational time for further assessment is reduced, as only the set of potentially critical buses is considered. The CBS method is based on the work in [33–35]. A heuristic approach is used to identify the buses which are regarded as most critical. Buses are scanned for three criteria indicating their criticality. Only buses which satisfy all three criteria are regarded as critical and qualify for the analysis in the TD simulation.

Criterion 1 - Bus Properties: Criterion one consists of two sub-criteria. The voltage level of the bus V_{bus} has to be above the specified threshold V_{min}. Only (extra) high voltage buses are considered because faults at higher voltage levels are more severe than at lower voltage levels. Moreover, the number of buses to be considered in the assessment is drastically reduced by excluding low and medium voltage buses.

The bus must be connected to at least one other bus by at least two in-service transmission lines ($ln \geq 2$). If buses would be only connected by one transmission line, the fault clearing by opening the breakers of the line would isolate the generator and it would lose synchronism due to the separation from the main grid. Therefore, these buses are excluded as switching of the breakers following a fault would always cause a loss of synchronism.

Criterion 2 - Bus Injected Active Power vs. Generator Active Power: The active power P_{in}, which is injected in the bus, is compared to the active power P_{SG}, produced by synchronous generators in the vicinity of this bus. The vicinity of the bus is defined as one or two buses away from the generator bus. This means that only buses which are at maximum two buses away from generator buses are considered in the assessment. More distant buses are discarded. The criterion comprises two sub-criteria which define a lower and upper threshold for the injected active power:

a) The injected active power of the bus must be greater than the specified threshold n_{min} of the active power produced by the generators in the vicinity of the bus. The threshold is variable, but it is suggested to set the threshold of the active power, injected in the bus, between $50 - 75\,\%$ of the active power produced by the SGs. This lower threshold ensures that only locally produced active power flows to the bus.

b) The injected active power of the bus must be lower than the specified threshold n_{max} of the active power produced by the generators in the vicinity of the bus. It is suggested to set the upper threshold between $120 - 150\,\%$ of the active power produced by the SGs. This upper threshold ensures that long distance flows are excluded and only local power flows between the upper and lower threshold are considered.

Criterion 3 - Bus Leaving Active Power: The amount of active power P_{out} which is leaving the bus on transmission lines sets the third criterion. Power flows on transformers are not taken into account. This criterion puts into perspective the active power that leaves the bus with the total generated active power of the considered power system. The active power, leaving the bus, must be greater than the specified threshold $P_{out,min}$. The threshold is variable, but it is suggested to set it to approximately $1\,\%$ of the total active power output $P_{SG_{tot}}$ of SGs of the considered system.

The criteria of the CBS, including the thresholds, suggested by the authors of [33–35], are summarized in Table 1.

Table 1: Summary of the Critical Bus Screening Criteria

Criterion	**Formulation**	**Suggested Threshold**
1	$V_{bus} \geq V_{min}$ $ln \geq ln_{min}$	highest voltage level $ln_{min} = 2$
2	$n_{min} \leq \frac{P_{in}}{P_{SG}} \leq n_{max}$	$n_{min} = \{0.5 - 0.75\}$ $n_{max} = \{1.2 - 1.5\}$
3	$P_{out} \geq P_{out,\,min}$	$P_{out,\,min} \approx 0.01 \cdot P_{SG_{tot}}$

3.4. Update of Simulation Model

The simulation model, which represents the real power system, has to be updated with data from the current system snapshot. The data includes generator schedule, breaker status, dispatch of capacitor banks and RES generation. The updated simulation model is then ready to be used in the TD simulation. Additionally, the results of the CBS are saved in a list which contains the identified critical buses. Only these buses are considered in the assessment.

3.5. Transient Stability Assessment and Dispatch Scheme

The potentially critical buses are analyzed in the transient stability assessment and dispatch scheme, which is based on a hybrid approach using an estimation of dispatch, combined with TD simulations. The flow chart of the dispatch procedure is shown in Fig. 2. The goal of the proposed procedure is to determine the dispatch volume which is needed to achieve the desired CCT and, therefore, return the system in safe state, while respecting technical constraints and minimizing costs.

FCCS: In the first step, a FCCS for the previously identified potentially critical buses is carried out using TD simulations. The goal is to identify the buses which are in fact critical and sort out the non-critical ones. The FCCS delivers a yes/no decision whether the system can withstand a three-phase fault with CCT_{lim} at the potentially critical buses without generators losing synchronism. This indicates whether the CCT of a three-phase fault at a

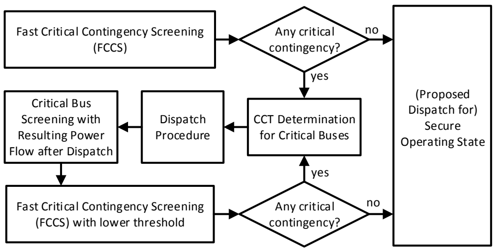


Figure 2: Flow Chart of the Transient Stability Assessment and Dispatch Scheme

bus is above or below the specified limit. However, no margins or CCTs are calculated in this step.

Decision: If the FCCS does not find a critical contingency, i.e. none of the applied three-phase faults caused a loss of synchronism of one or more machines, the assessment ends and a secure operating state, in terms of transient stability, is given. If the screening identifies contingencies where SGs are losing synchronism, the procedure continues with the determined set of critical buses.

CCT Determination: For the set of critical buses, CCTs are determined up to three decimals and the associated SGs which lose synchronism are noted. These SGs are regarded as critical and their active power has to be dispatched. The CCT was numerically determined within DIgSILENT PowerFactory environment using a DPL-script [36]. Consecutive bolted three-phase faults are applied on any line close to the busbar and removed after varying durations by opening the breakers of the line.

Dispatch procedure: The dispatch procedure starts with the SG which is associated with the bus with the lowest CCT and continues consecutively with CCTs in ascending order. On the one hand, this prevents a too large re-dispatch, due to the fact that the CCTs at adjacent buses can be close to each other whereas, generally, the one closer to the SG is lower. On the other hand, it reduces the number of required iterations to reach the optimal dispatch. The dispatch procedure is comprehensively described in Section 4. If the newly calculated set point for the generator is not compatible with the current set point and the time window given for ramping the generator, a new OPF, considering this new constraint, is calculated.

Critical bus screening with resulting power flow after dispatch: After the dispatch of all critical SGs, another CBS is carried out to determine the critical buses of the new load flow condition. That is conducted as preparation for the final FCCS.

FCCS with lower threshold: Another FCCS is carried out in order to verify the success of the dispatch, i.e. if the dispatch has re-established the desired transient stability margins. Since the dispatch procedure introduces an accuracy range of $\pm 5\,ms$ (see *Section 4, Step IV*) of the desired CCT, the final FCCS is executed with the lower limit of the accuracy range, i.e. $CCT_{lim} - 5\,ms$. If the FCCS identifies violations of CCTs, the procedure starts again from the CCT determination.

Secure operating state: If no further violations are identified, the procedure is completed and the results are presented to the control room operator.

3.6. Visualization and Decision Support for the Control Room Operator

The results of the transient stability assessment and the proposed dispatch are presented in comprehensive but condensed form to the control room operator as shown in Fig. 7 and 9. The situation awareness of the control room operator is increased as the stability margin is displayed graphically and the buses, at which the CCT is below the limit, are shown in a table format. Additionally, the generators and their respective dispatch to achieve the desired stability margin are shown numerically. Furthermore, the associated costs of the proposed dispatch are stated. If the proposed dispatch does not meet the requirements of the operator for some reason, e.g. one of the selected SGs is not available for the re-dispatch, the operator has the possibility to interact with the decision support system by blocking the power setpoint of the specific SG and restart the dispatch procedure in order to get a new dispatch proposal considering the special requirement.

The amount of information presented to the control room operator is kept low in order not to overload it and to facilitate fast understanding of the condition. Moreover, warning signals could be generated when the CCT is below a specified limit, e.g. 200 ms. Different levels of severity can then be added depending on the size of the critical unit. If there is a need for in-depth information, the control room operator should be given the possibility to access the underlying data, e.g. reactive power set points.

4. Dispatch Procedure in Detail

Step I

The dispatch procedure starts with the SG that is associated with the contingency with the lowest CCT. The initial power setpoint of the SG and the respective CCT is noted. The two variables of the initial condition are called P_{init} and CCT_{init}, respectively.

Step II

The maximum power setpoint of the SG which satisfies the minimum desired CCT limit has to be determined. Since it cannot be calculated analytically for multi-machine systems, a TD approach using an estimation of the dispatch is proposed. To get the first estimation, it is proposed to use the linear approximation, which is shown in Fig. 3, where η represents the ratio between initial and desired minimum CCT shown in (1), and m the dispatch estimation factor, which is used to calculate the estimated power setpoint P_{est} from the initial setpoint P_{init}, shown in (3). The idea behind the linear approximation of the active power dispatch from the CCT ratio originates from the fact that the relationship is almost linear, but not exactly known unless several Power-CCT pairs are determined. Since the calculation of several Power-CCT pairs poses a computational burden, an alternative approach is presented in this paper. Certainly, the relationship between the active power output of generators and the CCT is not perfectly linear, as various parameters are influencing the CCT. However, the proposed estimation method is only an intermediate step in the dispatch procedure, which showed to be very handy to get a first guess of the required dispatch. The exact dispatch is calculated in the subsequent steps of the procedure. The proposed relationship of m and η shown in Fig. 3 and (2) was determined heuristically, by simulation of numerous scenarios with different grid configurations, and was found suitable for the two presented case studies while it may need to be adjusted for different grids.

$$\eta = \frac{CCT_{init}}{CCT_{lim}} \tag{1}$$

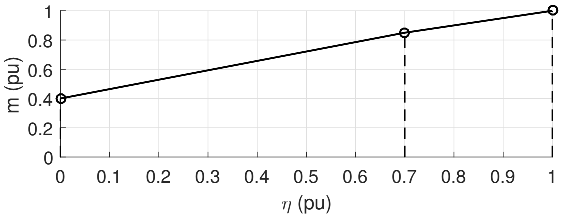


Figure 3: Estimation of the generator's power setpoint

$$m = \begin{cases} 0.5 \cdot \eta + 0.5 \; for \; \eta \geq 0.7 \\ 0.6429 \cdot \eta + 0.4 \; for \; \eta < 0.7 \end{cases} \tag{2}$$

$$P_{est} = m \cdot P_{init} \tag{3}$$

Step III

The estimated power setpoint P_{est} is used as the new power setpoint of the SG. The dispatch, i.e. the difference between the initial and the new setpoint, is distributed to other SGs by employing an OPF calculation minimizing the costs of generation. Technical constraints, such as maximum line flows, voltage levels and maximum/minimum active power of the generators, are considered in the OPF calculation. The active power setpoints of SGs, which were identified as critical within the FCCS, are locked in the OPF calculation as they are not allowed to increase their active power, since they are already critical. Only SGs which are not considered critical are allowed to take over the dispatch. The setpoints obtained by the OPF calculation are the new setpoints for the next step. The OPF calculation was carried out in DIgSILENT PowerFactory environment, which applies an interior-point algorithm based on the Newton-Lagrange method to solve the problem. In general, any other OPF calculation method can be used to solve the OPF problem.

Step IV

After obtaining the new active power setpoints through the OPF calculation, the CCT for the new load flow condition is calculated and the respective CCT is straightforwardly called CCT_{est}. As the power setpoint is only an estimation, the respective CCT will (most likely) not match CCT_{lim}. Therefore, a linearization between the initial and actual setpoint is

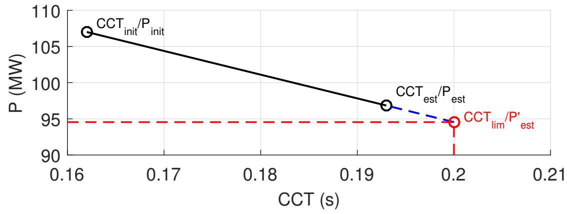


Figure 4: Extrapolation of initial and estimated condition to obtain the next power setpoint P'_{est}, for which CCT'_{est} is determined. (Values of the plot are irrelevant, but they are shown for clarity.)

conducted and the next active power setpoint P'_{est} is obtained from the inter- or extrapolation as shown in Fig. 4. CCT'_{est} for the new setpoint P'_{est} is determined and the procedure is terminated if CCT'_{est} lies between $\pm 5\,ms$ of CCT_{lim}. This $\pm 5\,ms$ accuracy band is suggested in order to avoid too many iterations.

5. Case Study

The capabilities of the approach are demonstrated by using two well-established benchmark grids. Firstly, the approach is applied to the nine-bus system shown in Fig. 6 to highlight the steps of the procedure while keeping the complexity low. Secondly, by using the New England system, shown in Fig. 8, it is shown that the approach is robust when taking into account a larger grid with numerous components and complex dynamic behavior.

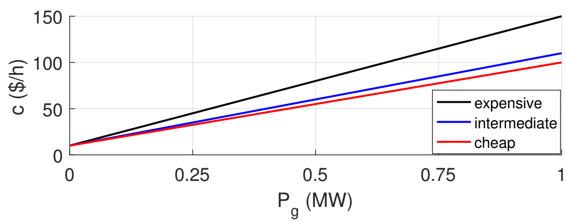


Figure 5: Cost functions of the SGs

In both studies, the initial operating point is determined by an OPF, minimizing the costs of generation using three standard cost functions shown in Fig. 5. Starting from that point, the transient stability preventive control approach is carried out for both benchmark grids. The CBS is only carried out for the New England system since its aim is to reduce the number of considered buses. Loads are modelled as voltage and frequency dependent

(P = const. current, Q = const. impedance, f_p = 1.5, f_q = -1) [37]. The voltage dependence is defined according to the ZIP definition, the frequency dependence is linear and the parameters are set according to the common practice for stability studies [38].

5.1. Case Study 1: Nine-Bus System

The nine-bus system, including the parameters of the elements, was firstly introduced in [39]. Only minor changes were made, such as the frequency which was set to $50\,Hz$ and G_2 and G_3 which are operated in PV mode while G_1 serves as slack generator. The voltage setpoint of all SGs is set to $1\,pu$.

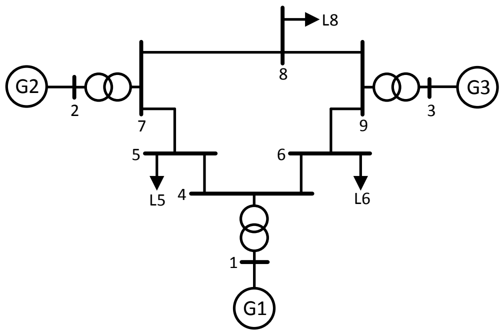


Figure 6: Nine-Bus System

G_1, G_2 and G_3 are associated with the expensive, intermediate and cheap cost functions according to Fig. 5, respectively. Table 2 shows the most important variables, such as active power, loading and costs during the different steps of the dispatch procedure. Initially, G_2 and G_3 are operated at their maximum active power limit, whereas G_1 is less loaded, which is expected due to their cost functions. The starting point of the procedure is the FCCS, as the CBS is not appropriate for this small grid. In the following paragraphs, the procedure is explained stepwise. The labels of the steps correspond to the ones in Section 3 and 4.

FCCS: The FCCS identified the buses six, seven and nine as critical, because SGs are losing synchronism.

CCT Determination: Following the FCCS, the CCTs for the identified buses are determined. The CCTs of all buses are shown in Fig. 7. The CCTs of the buses six, seven and nine are $0.171\,s$, $0.159\,s$ and $0.149\,s$, respectively. All three are below CCT_{lim} and, hence, considered to be critically low.

Dispatch of G_3

Step I: The dispatch starts with the lowest CCT and its associated SG, which is in this case at bus nine ($CCT^{(Bus\ 9)} = 0.149\,s$) and is caused by G_3.

Step II: The power setpoint is estimated according to (1)-(3). The estimation results in $P_{est}^{(G_3)} = 94.93\,MW$.

Step III: The estimated power setpoint for G_3 is fixed in the OPF calculation. Since G_2 is also critical due to low CCT, the maximum active power is constrained to its initial value. It has to be emphasized that it is important to constrain critical SGs to their initial power setpoints since a dispatch to the critical SGs would decrease the CCT even further.

Step IV: Given the newly obtained load flows, the CCT for bus nine is determined and $CCT_{est}^{(Bus\ 9)}$ is equal to $0.191\,s$. The linear extrapolation between the initial and new condition, according to Fig. 4, results in $P_{est}'^{(G_3)} = 91.96\,MW$ and $CCT_{est}'^{(Bus\ 9)} = 0.202\,s$. As $CCT_{est}'^{(Bus\ 9)}$ lies inside the accuracy band of $\pm 5\,ms$, the dispatch of G_3 is finished.

After the dispatch of G_3, the next SG has to be dispatched. $CCT^{(Bus\ 7)}$ is equal to $0.159\,s$ and the associated SG is G_2. Since one SG has already been dispatched, the CCT of bus seven has to be calculated again before starting the procedure.

Dispatch of G_2

Step I: The CCT of bus seven after the dispatch of G_3 is already higher than initially and is equal to $CCT'^{\,(Bus\ 7)} = 0.175\,s$ while the active power setpoint is still $163.20\,MW$.

Step II: By applying (1)-(3), the estimated power setpoint $P_{est}'^{(G_2)}$ results in $153\,MW$.

Step III: The OPF calculation is carried out with the active power setpoint of G_2 fixed to $153\,MW$ and G_3 to $91.96\,MW$, which was determined by the dispatch procedure of G_3.

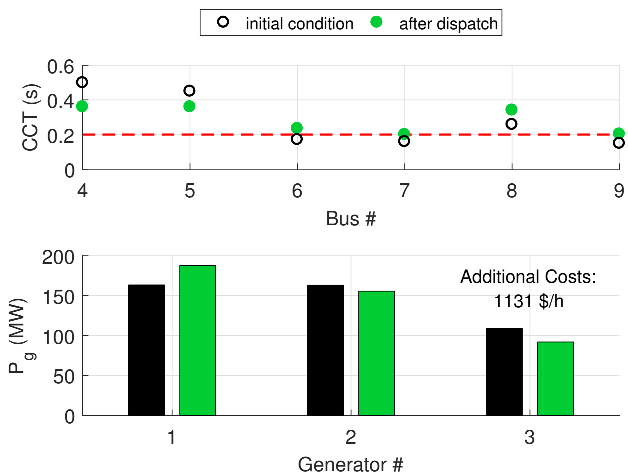
Step IV: The CCT for bus seven for the new load flow is $CCT_{est}^{(Bus\ 7)} = 0.209\,s$. The linear interpolation between the initial and the new condition results in $P_{est}'^{(G_2)} = 155.70\,MW$ and $CCT_{est}'^{(Bus\ 7)} = 0.2\,s$. The dispatch procedure for G_2 is finished as $CCT_{est}'^{(Bus\ 7)}$ equals exactly CCT_{lim}.

Discussion of Case Study 1: The results after the dispatch procedure compared to the initial condition are shown in Fig. 7 in graphical and digital form. The critical CCTs are elevated, so that all CCTs in the system meet the specified limit. The CCTs of bus seven

Table 2: Active power setpoints, loading and costs during the dispatch

State		G_1	G_2	G_3
Initial condition	P_g (MW)	163.44	163.20	108.80
	Loading (%)	67	85	85
	costs ($/h)	22891	16330	9802
	total costs ($/h)	49023		
After dispatch of G3	P_g (MW)	180.21	163.20	91.96
	Loading (%)	73	85	72
	costs ($/h)	25240	16330	8286
	total costs ($/h)	49856 (+833)		
After dispatch of G2	P_g (MW)	187.70	155.70	91.96
	Loading (%)	76	81	72
	costs ($/h)	26288	15580	8286
	total costs ($/h)	50154 (+1131)		

and nine are exactly at the limit, i.e. that only the minimal necessary amount of power has been dispatched in order to meet the predefined level of transient stability. An important observation can also be made by comparing the CCTs of the other buses. The CCTs of bus four and five are lower for the new system state, which can be expected due to the fact that G_1 has taken over the dispatched power from G_2 and G_3. Moreover, the CCT of the buses six and eight are also elevated, compared to the initial condition, as they are adjacent to the buses, which were considered in the dispatch. The lower plot visualizes the active power change of the individual generators and the additional costs, which would be caused by the dispatch.



Additional costs of re-dispatch: 1131 $/h			
	critical CCTs (s)		
Bus	6	7	9
initial	0.171	0.159	0.149
after	0.235	0.2	0.203
	P_g (MW)		
Gen.	1	2	3
initial	163.4	163.2	108.8
after	187.7	155.7	91.96
delta	+24.3	-7.5	-16.84

Figure 7: CCTs and active power setpoints for the initial condition and after the successful re-dispatch

5.2. Case Study 2: New England System

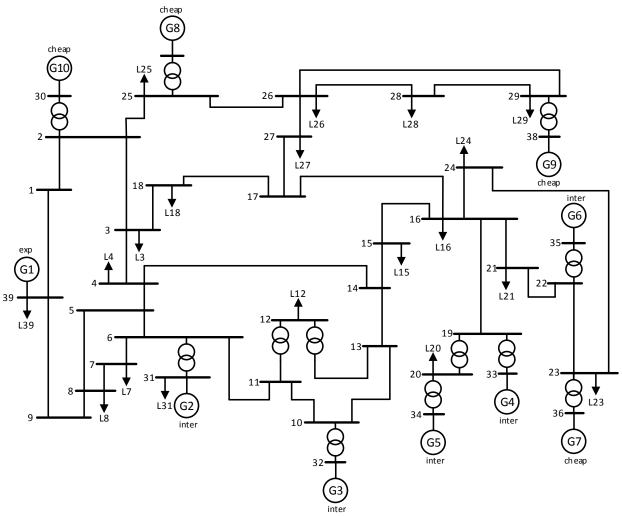


Figure 8: New England System with indication of associated cost functions

The New England system with 39 buses and 10 SGs is a well-established model and has been extensively used for scientific research. Therefore, it is used to show that the newly introduced dispatch approach is robust and can be applied to larger grids. Similar to the nine-bus system, a few minor changes were introduced to the system described in [40]. In this case, nominal frequency was also set to $50\,Hz$ and all generators are operated in PV mode with voltage setpoints of $1.02\,pu$. G_1 serves as slack generator. In this case study, all elements of the transient stability approach, including the CBS, are shown.

CBS: The used thresholds of the CBS and the identified buses, which are considered as potentially critical, are shown in Table 3. Thirteen out of 39 buses are identified to be potentially critical, i.e. only one third of the buses has to be considered in the further assessment, which significantly reduces the computational burden.

FCCS: The FCCS identified the buses 21, 22, 23 and 29 as critical as shown in Table 3.

CCT Determination: The CCTs of the four identified buses are determined. The CCTs are equal to $0.181\,s$, $0.137\,s$, $0.153\,s$ and $0.158\,s$ for bus 21 (G_6), 22 (G_6), 23 (G_7) and 29 (G_9), respectively. All CCTs are below the specified limit (as expected) and considered critically low.

Dispatch of G_6

Table 3: Thresholds and results of CBS and FCCS

Criterion	**Threshold**
1	$V_{min} = 345\,kV$, $ln_{min} = 2$
2	$0.6 \leq \frac{P_{in}}{P_{Gen}} \leq 1.4$
3	$P_{out,\,min} = 62\,MW$
Potentially Critical Buses According to CBS	
2, 5, 10, 11, 13, 16, 21, 22, 23, 25, 26, 29, 39	
Buses, Identified as Critical by FCCS	
21, 22, 23, 29	

Step I: The dispatch starts again with the lowest CCT, which is $0.137\,s$ at bus 22, caused by G_6. Therefore, the initial active power setpoint and the associated CCT are noted.

Step II: The estimated dispatch is calculated by using (1)-(3) and results in $P_{est}^{(G_6)} = 423.47\,MW$.

Step III: The estimated power setpoint for G_6 is fixed in the OPF calculation. Since G_7 and G_9 are also critical, they are not available for re-dispatch and, thus, their active power setpoint is limited to the initial one.

Step IV: Given the newly obtained load flow, the CCT is determined and it is equal to $CCT_{est}^{(Bus\ 22)} = 0.173\,s$. The linear extrapolation between the initial and new conditions, according to Fig. 4, results in $P'\ (Bus\ 22)_{est} = 363.14\,MW$ and $CCT'^{(Bus\ 22)}_{est} = 0.199\,s$. The dispatch of G_6 is done as $CCT'^{(Bus\ 22)}_{est}$ lies between $CCT_{lim} \pm 5\,ms$.

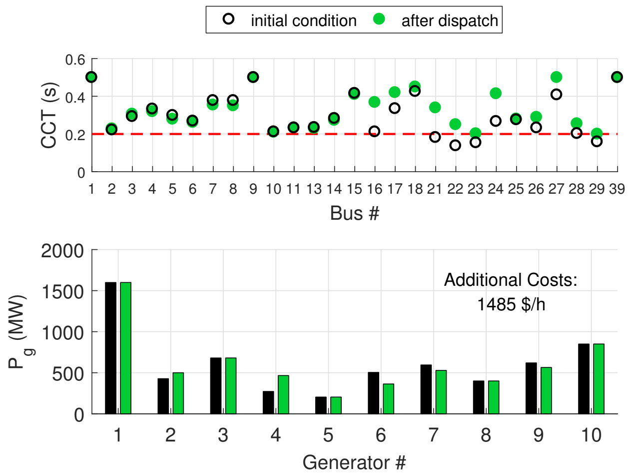
Dispatch of G_7 and G_9

After the dispatch of G_6, the same procedure is carried out for G_7 and G_9, which is shown in Table 4.

Table 4: Variables during the dispatch procedure of each generator

	G_6		G_7		G_9	
	P_g (MW)	CCT (s)	P_g (MW)	CCT (s)	P_g (MW)	CCT (s)
initial	503.90	0.137	594.98	0.155	620	0.158
est	423.47	0.173	528.04	0.2	554.90	0.207
est'	363.14	0.199	-	-	564.19	0.199

Discussion of Case Study 2: Table 4 shows the active power setpoints and its resulting CCT throughout the re-dispatch procedure. The procedure for all three SGs converged within one iteration. The estimated setpoint for G_7 was already correctly approximated and the linearization between initial and new condition was not necessary. The CCTs and active power dispatch of the initial condition and after the dispatch procedure are summarized in Fig. 9. It can be seen that all CCTs meet the specified limit after the successful dispatch. The CCTs at bus 23 and 29 are exactly at the limit, whereas bus 22 is even more elevated than it was actually determined. Due to the close proximity of G_7 to G_6, the dispatch of G_7 also affected the CCT at bus 22. Due to the influence of the generators in close proximity, only a near optimal solution is found which illustrates one of the drawbacks of the sequential approach.



Additional costs of dispatch: 1485 $/h					
	critical CCTs (s)				
Bus	21	22	23	29	
initial	0.181	0.137	0.153	0.158	
after	0.338	0.249	0.201	0.199	
	Pg (MW)				
Gen.	2	4	6	7	9
initial	427.8	272	503.9	595	620
after	500	465.9	363.1	528	564.2
delta	+72.2	+193.9	-140.8	-67	-55.8

Figure 9: CCTs and active power setpoints for initial condition and after successful dispatch

5.3. Evaluation of Execution Time of the Assessment

It is of crucial importance that the decision support tool delivers results within a reasonable time, irrespectively of the size and complexity of the power system. Therefore, the execution time for the nine-bus, New England and for the IEEE 118-bus test system, found in [41], is analyzed. The execution times of the blocks in the flow chart of Fig. 2 including the CBS of the New England system are reported in Table 5.

In order to make the results comparable, the shown execution times are expressed as execution time per critical bus fault location. The total execution time of the different process steps is divided by the number of assessed buses for which it is carried out. The CBS is only shown for the New England system and is equal to $0.103\,s$. It was not implemented for the two other test systems, but it can be expected to be in the same order of magnitude for larger networks as the calculation complexity of this step is fairly low. The determining factors of the overall execution time are the CCT and FCCS calculations which have the highest execution time per bus. The overall execution time is not shown as it highly depends on the state of the system, i.e. the number of buses, for which the FCCS is carried out and the CCT has to be determined exactly. The execution time of the OPF is also relatively small compared to the other process steps because the optimization only considers the costs. It should be noted, that the execution time of the OPF will increase with increased complexity of the problem, e.g. inclusion of additional objectives. It can be observed that the execution times increase with increased grid size.

Table 5: Results of the execution time evaluation

System	# of SGs	CBS (s)	FCCS/Bus (s)	CCT/Bus (s)	OPF (s)
9-Bus	3	-	0.3	1.13	0.2
39-Bus	10	0.103	0.85	2.59	0.4
118-Bus	54	-	1.08	6.95	0.75

The presented execution times have not been optimized and have been achieved on a standard laptop (quad-core i7 4600, 8 GB RAM) with PowerFactory V 15.2 and Matlab 2016b software. Therefore, one should keep in mind that the execution time will be reasonably lower with more powerful units such as the ones used in control rooms. Moreover, the implementation of the assessment has significant impact on the execution time, e.g. the authors of [42] claim that they can assess the CCT of 39.000 buses within minutes, hence, the authors expect that an efficient implementation of the presented approach, paired with more powerful hardware, will result in acceptable execution times suitable for online application. According to [19], an execution time within $15\,min$ is seen as a reasonable time horizon for online application.

6. Conclusion

The paper presented a decision support tool for control room operators for transient stability preventive control. A novel dispatch procedure for multi-machine systems was introduced. OPF calculations were used to re-distribute the dispatched power while costs are minimized. The sequential approach delivers a near optimal solution in terms of cost minimization. However, the transient stability assessment is carried out transparently and therefore, the control room operator is presented with a traceable dispatch proposal. In order to reduce the computational burden of the approach, the dispatch procedure is complemented with a preceding CBS and a FCCS to reduce the number of buses to be considered in the assessment. Case Study 2 showed that the number of buses can be significantly reduced by applying the CBS and FCCS. The proposed approach shows to be robust when applied to larger power systems. The execution time of the process steps was evaluated for different network sizes. It showed that the FCCS and CCT determination are the two most contribution factors to the overall execution time. However, the execution times have been achieved on a standard laptop (quad-core i7 4600, 8 GB RAM). Considering more powerful hardware used in control rooms and efficient implementation, the authors anticipate acceptable execution times suitable for online application of the tool. In this work, only the minimization of costs, considering technical constraints, was the objective of the OPF calculation. Of course, the OPF calculation can be extended to include multiple objectives, such as grid losses in addition to generation costs. Multi-objective minimization was not considered in this work since the objectives of the minimization depend on the specific power system operator and the OPF calculation can be adapted within the approach in order to meet user-specific needs. Special attention has to be paid to load modeling due to its great impact on the results in terms of CCT. The load behavior of the considered system has to be known in order to achieve realistic results. In fact, incorrect load modeling will result in significant differences in the determined CCT and, therefore, in the calculated dispatch. It was shown, that the dispatch procedure converges usually within one iteration. In worst case, it requires a second iteration to converge. Future work will investigate the sensitivity of the proposed approach to load modeling. Moreover, an in-depth analysis of the expected execution time for larger and more complex networks will be carried out.

Acknowledgment

Michael Pertl is a PhD student at the Technical University of Denmark (DTU) and is supported by the EU FP7 project ELECTRA (grant: 609687) and the Danish Research Project ELECTRA Top-up (grant: 3594756936313). More information can be found at electrairp.eu.

References

[1] M. Panteli, P. A. Crossley, D. S. Kirschen, D. J. Sobajic, Assessing the Impact of Insufficient Situation Awareness on Power System Operation, IEEE Transactions on Power Systems 28 (3) (2013) 2967–2977. doi:10.1109/TPWRS.2013.2240705.

[2] M. Panteli, D. S. Kirschen, Situation awareness in power systems: Theory, challenges and applications, Electric Power Systems Research 122 (2015) 140–151. doi:10.1016/j.epsr.2015.01.008.

[3] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, Tech. rep., U.S. Department of Energy and Canadian Ministry of Natural Resources (2004).

[4] UCTE Investigation Committee, FINAL REPORT of the Investigation Committee on the 28 September 2003 Blackout in Italy, Tech. rep., Union for the Co-ordination of Transmission of Electricity (UCTE) (2004). arXiv:arXiv:1011.1669v3, doi:10.1017/CBO9781107415324.004.

[5] E. S. Connors, M. Endsley, L. Jones, Situation Awareness in the Power Transmission and Distribution Industry, in: 51st Annual Meeting of the Human Factors and Ergonomics Society, Santa Monica, 2007, pp. 215–219.

[6] M. R. Endsley, E. S. Connors, Situation Awareness: State of the Art, in: Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century, Pittsburgh, 2008, pp. 1–4. doi:10.1109/PES.2008.4596937.

[7] M. Endsley, Situation Awareness in the Bulk Power System, in: Human Performance Conference, Atlanta, 2012, p. 45.

[8] M. Panteli, D. S. Kirschen, P. A. Crossley, D. J. Sobajic, Enhancing Situation Awareness in Power System Control Centers, in: IEEE International Multi-Disciplinary Conference on Cognitive Methods in Situation Awareness and Decision Support (CogSIMA), San Diego, 2013, pp. 254–261.

[9] K. Visscher, M. Marinelli, A. Z. Morch, S. H. Jakobsson, Identification of observables for future grids - the framework developed in the ELECTRA project, in: PowerTech, Eindhoven, 2015, pp. 1–6.

[10] L. E. Jones, Strategies and Decision Support Systems for Integrating Variable Energy Resources in Control Centers for Reliable Grid Operations, Tech. rep., Alstom Grid Inc., Washington, DC (2011).

[11] P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. Van Vutsem, V. Vittal, Definition and Classification of Power System Stability, IEEE Transactions on Power Systems 21 (3) (2004) 1387–1401. doi:10.1109/TPWRS.2004.825981.

[12] A. Atputharajah, T. K. Saha, Power system blackouts - literature review, in: International Conference on Industrial and Information Systems (ICIIS), Sri Lanka, 2009, pp. 460–465. doi:10.1109/ICIINFS.2009.5429818.

[13] T. Weckesser, H. Johannsson, S. Sommer, J. Østergaard, Investigation of the Adaptability of Transient Stability Assessment Methods to Real- Time Operation, in: 3rd IEEE PES International Conference and Exhibition on Innovative Smart Grid Technologies (ISGT Europe), Berlin, 2012, pp. 1–9. doi:10.1109/ISGTEurope.2012.6465835.

[14] M. Pertl, M. Rezkalla, M. Marinelli, A Novel Grid-Wide Transient Stability Assessment and Visualization Method for Increasing Situation Awareness of Control Room Operators, in: IEEE PES Innovative Smart Grid Technologies Conference Asia (ISGT), Melbourne, 2016, pp. 1–6.

[15] Y. Kato, S. Iwamoto, Transient stability preventive control for stable operating condition with desired CCT, IEEE Transactions on Power Systems 17 (4) (2002) 1154–1161. doi:10.1109/TPWRS.2002.805019.

[16] K. Yoda, T. Okuda, T. Ohtaka, S. Iwamoto, K. Nagaura, H. Ito, Y. Onoue, Transient Stability Preventive Control with Optimal Power Flow, in: International Conference on Power System Technology (POWERCON), Chengdu, 2004, pp. 102–107.

[17] H. Takada, Y. Kato, S. Iwamoto, Transient Stability Preventive Control Using CCT and Generation Margin, in: Power Engineering Society Summer Meeting, Vancouver, 2001, pp. 881–886.

[18] S. Savulescu, Real-Time Stability in Power Systems, 2nd Edition, Springer, 2014. doi:10.1007/978-1-4614-0134-6.

[19] A. Bihain, D. Cirio, M. Fiorina, R. Lopez, D. Lucarella, S. Massucco, D. Ruiz-Vega, C. Vournas, T. Van Cutsem, L. Wehenkel, Omases : A Dynamic Security Assessment Tool for the New Market Environment, in: IEEE PowerTech, Bologna, 2003, pp. 1–8.

[20] D. Ruiz-Vega, M. Pavella, A Comprehensive Approach to Transient Stability Control: Part INear Optimal Preventive Control, IEEE Transactions on Power Systems 18 (4) (2003) 1446–1453. doi:10.1109/TPWRS.2003.818708.

[21] R. Zárate-Miñano, T. V. Cutsem, F. Milano, A. J. Conejo, Securing Transient Stability Using Time-Domain SimulationsWithin an Optimal Power Flow, IEEE Transactions on Power Systems 25 (1) (2010) 243–253.

[22] A. Pizano-Martinez, C. R. Fuerte-Esquivel, D. Ruiz-Vega, A New Practical Approach to Transient Stability-Constrained Optimal Power Flow, IEEE Transactions on Power Systems 26 (3) (2011) 1686–1696. doi:10.1109/TPWRS.2010.2095045.

[23] C. Machado Ferreira, F. P. Maciel Barbosa, C. I. Faustino Agreira, Transient Stability Preventive Control of an Electric Power System Using a Hybrid Method, in: 11th International Middle-East Power System Conference (MEPCON), Aswan, 2008, pp. 141–145.

[24] D. Cirio, D. Lucarella, G. Vimercati, S. Massucco, A. Morini, F. Silvestro, D. Ernst, M. Pavella, L. Wehenkel, Application of an Advanced Transient Stability Assessment and Control Method To a Realistic Power System, in: Power Systems Computation Conference (PSCC), Liege, 2005, pp. 1–8.

[25] D. Gan, R. Thomas, R. Zimmerman, Stability-Constrained Optimal Power Flow, IEEE Transactions on Power Systems 15 (2) (2000) 535–540. doi:10.1109/59.867137.

[26] M. La Scala, M. Trovato, C. Antonelli, On-line dynamic preventive control:An algorithm for transient security dispatch, IEEE Transactions on Power Systems 13 (2) (1998) 601–610. doi:10.1109/59.667388.

[27] A. Pizano-Martinez, C. R. Fuerte-Esquivel, D. Ruiz-Vega, Global transient stability-constrained optimal power flow using an OMIB reference trajectory, IEEE Transactions on Power Systems 25 (1) (2010) 392–403. doi:10.1109/TPWRS.2009.2036494.

[28] A. Pizano-Martinez, C. R. Fuerte-Esquivel, E. Zamora-Cardenas, D. Ruiz-Vega, Selective transient stability-constrained optimal power flow using a SIME and trajectory sensitivity unified analysis, Electric Power Systems Research 109 (2014) 32–44. doi:10.1016/j.epsr.2013.12.003.

[29] D. Ernst, D. Ruiz-Vega, M. Pavella, P. M. Hirsch, D. Sobajic, A Unified Approach to Transient Stability Contingency Filtering, Ranking and Assessment, IEEE Transactions on Power Systems 16 (3) (2001) 435–443. doi:10.1109/59.932279.

[30] D. Ruiz-Vega, M. Pavella, A Comprehensive Approach to Transient Stability Control: Part IIOpen Loop Emergency Control, IEEE Transactions on Power Systems 18 (4) (2003) 1454–1460. doi:10.1109/TPWRS.2003.818707.

[31] J. L. Pardo, J. C. Elmore, V. G. Duong, 500 kV IPT Breaker Failure Protection: An Application of Dual Timer Scheme for Short Critical Clearing Time, in: 65th Annual Conference for Protective Relay Engineers, College Station, 2012, pp. 120–128. doi:10.1109/CPRE.2012.6201226.

[32] M. Glavic, T. Van Cutsem, Reconstructing and tracking network state from a limited number of synchrophasor measurements, IEEE Transactions on Power Systems 28 (2) (2013) 1921–1929. doi:10.1109/TPWRS.2012.2231439.

[33] V. Kolluri, S. Mandal, M. Y. Vaiman, M. M. Vaiman, S. Lee, P. Hirsch, Fast Fault Screening Approach to Assessing Transient Stability in Entergy's Power System, in: IEEE Power Engineering Society General Meeting, Tampa, 2007, pp. 1–6.

[34] S. Lee, L. Min, M. Vaiman, Fast Fault Screening for Real-Time Transient Stability Assessment, Tech. rep., Electric Power Research Institute (EPRI) and V&R Energy System Research Inc. (2010).

[35] M. Y. Vaiman, M. M. Vaiman, A. Gaikwad, Fast Fault Screening Methodology for Transient Stability Analysis of Bulk Power Systems, in: IEEE Power and Energy Society General Meeting, Vancouver, 2013, pp. 1–5.

[36] DIgSILENT PowerFactory, Use of DPL to determine the critical clearing time of a fault (2016). URL http://goo.gl/J0dtnk

[37] M. Marinelli, M. Pertl, M. Rezkalla, M. Kosmecki, S. Canavese, A. Obushevs, A. Morch, The Pan-European Reference Grid Developed in the ELECTRA Project for Deriving Innovative Observability Concepts in the Web-of-Cells Framework, in: 51th International UniversitiesPower Engineering Conference (UPEC), Coimbra, 2016, pp. 1–6.

[38] K. Sun, Power System Operations & Planning Load Modeling (2015).

[39] P. M. Anderson, A. A. Fouad, Power System Control and Stability, 1st Edition, Iowa State University Press, Ames, 1977.

[40] DIgSILENT PowerFactory, Description of the 39 Bus New England System, Tech. rep., DIgSILENT GmbH, Gomaringen (2015).

[41] P. Demetriou, M. Asprou, J. Quiros-Tortos, E. Kyriakides, IEEE 118-bus modified test system (2016). URL http://www.kios.ucy.ac.cy/testsystems/index.php/dynamic-ieee-test-systems/ieee-118-bus-modified-test-system

[42] S. Kolluri, M. Li, A. Lazo, P. Yu, M. Vaiman, M. Vaiman, Automated Critical Clearing Time Calculation for Analyzing Faults at Entergy, in: IEEE/PES Transmission and Distribution Conference and Exposition (T&D), Dallas, 2016, pp. 1–5. doi:10.1109/TDC.2016.7520001.