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Enhanced stability of EHV power networks with HVDC connections

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***Abstract*—This paper deals with the topic of power system stability in the case of expanding a conventional three-phase AC grid with HVDC connections. With respect to the requirements of modelling power system elements for stability studies a simulation model is built. A fast method for evaluating the power system stability based on modal analysis is proposed. Different scenarios of expanding or replacing overhead power lines of the original grid with HVDC connections are compared and evaluated. Three-phase faults at all buses and lines are simulated with different fault clearing times. In most cases a positive influence of the HVDC connections on the rotor angle stability is presented.**

***Index Terms*—HVDC transmission system, power system modelling, stability analysis, modal analysis.**

I. Introduction

The increased centralized infeed of wind power into the extra high voltage (EHV) power grid of the UCTE network and, as a result, the transfer of large amounts of electric power over long distances to the consumption centres causes many problems concerning

- the capacity for the power transfer,
- the controllability of the grid,
- the power system stability and
- the quality of electric power supply.

An expansion of the power grid is necessary in order to keep a high availability and reliability of the electric power supply. To overcome these problems the HVDC technology could be used and is analysed in this paper. Towards the conventional three-phase AC technology it has a number of advantages including a high degree of controllability [1]. Furthermore the grid integration of offshore wind power farms will be realized with HVDC soon. A further expansion of these HVDC connections seems to be sensible.

This paper presents a method for power system stability analysis and the results of dynamic simulations of a conventional AC technology test system which is expanded with parallel HVDC connections. In section II the model of the test system is described. Section III provides a short explanation of power system stability. The modelling of the HVDC technology is explained in section IV. Different scenarios of expanding or replacing parts of the test system with HVDC connections are compared and evaluated. The results are explained in section V. At the end of this paper a conclusion is drawn.

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II. Preparation of a test system

Based on dynamic simulations the power system stability [2] of a test system which will be expanded with parallel HVDC connections is investigated. The simulations are done with DIgSILENT PowerFactory [3]. This software enables a highly accurate modelling of power systems and provides all necessary tools for stability analysis.

A. Modelling

The IEEE 10 Generator 39 Bus System (Fig. 1) is used as test system. The full system data of the power grid, except controller models and parameters, are given in [4]. All generators are modelled with the 6th-order synchronous machine model and are equipped with speed governors, automatic voltage regulators (AVRs) and power system stabilizers (PSSs). The structures and parameters of the controller models which are also used in practice are implemented by using block diagrams. Furthermore all transformers are equipped with tap changers and internal voltage controllers.

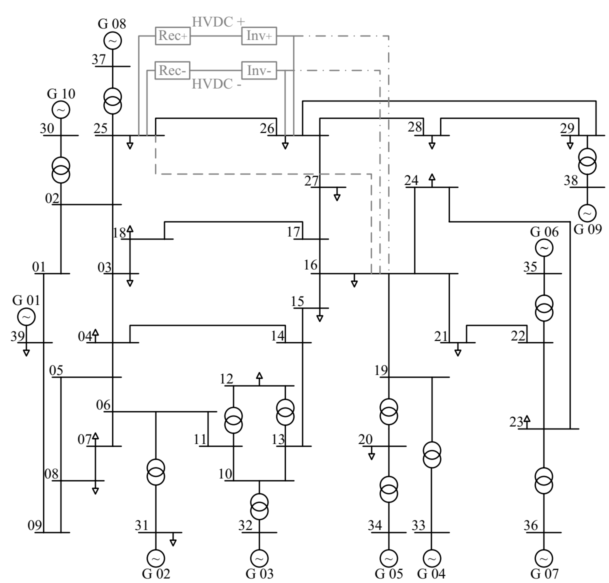

Fig. 1. Modified IEEE 10 Generator 39 Bus System

B. Verification

In order to verify the implemented power system model first a load flow analysis is performed. The comparison of the results with the data provided in [4] shows no difference in voltage magnitudes at all buses. The voltage angles only differ at four buses from the original data, whereas the maximum error is only $1.22\,\%$. Hence the system is working correctly and can be used for the following simulations. The results of dynamic simulations cannot be compared with [4] due to different fundamental frequencies and different synchronous machine models.

A verification of the speed governors and AVRs is done by transient simulations of a simple test network which consists of one generator ($S_{\mathrm{r}} = 1000\,\mathrm{MVA}$) supplying one load ($P = 300\,\mathrm{MW}$, $Q = 250\,\mathrm{MVar}$). The regulators are tested by a sudden increase of the active resp. reactive power about $50\,\%$ of the original value. This causes intervention of the speed governor resp. the AVR. The trends of the generator speed (Fig. 2) and generator terminal voltage (Fig. 3) indicate correct behaviour of the controllers.

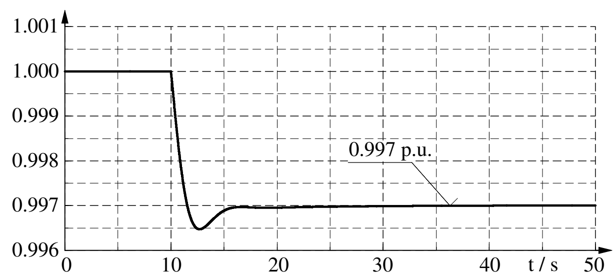

Fig. 2. Generator test: speed in p.u.

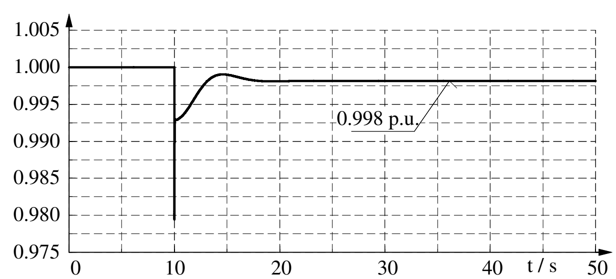

Fig. 3. Generator test: terminal voltage in p.u.

The PSSs are not explicit tested. Based on modal analyses (see also section III) the PSSs are empirical tuned in order to get a good damping of all oscillatory modes.

Simulations of three phase faults at all buses with different fault clearing times indicate that the implemented test system with the original load data from [4] is highly stable. Effects of power system instability are only observable under severe conditions. For this reason a modification of the test system is necessary. To weaken the system stability the loads at all buses are increased by $20\,\%$. To allow conclusions which can be compared with the UCTE power grid, all data are converted to a frequency of $f = 50\,\mathrm{Hz}$.

III. Analysis of power system stability

Power system stability is a highly complex topic. An accepted definition and the common classification into rotor angle stability, frequency stability and voltage stability is given in Fig. 4. These three categories differ primarily in the time frame of interest and therefore have different requirements concerning the modelling of power system elements for stability simulations. This paper focus on rotor angle stability.

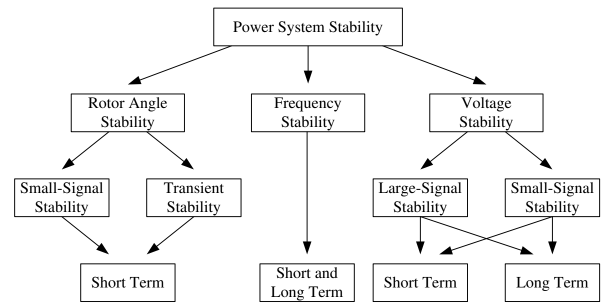

Fig. 4. Classification of power system stability [5]

A. *Rotor angle stability*

This stability aspect is further classified into small-signal stability and transient stability. There are different methods of analysing these two kinds of stability. The first one is the modal analysis (also known as Lyapunov‘s first method) [6]. It allows the evaluation of rotor angle stability for small disturbances (e.g. load changes) by linearising the system equations at one simulation time. If the system experiences a severe fault (e.g. a three phase fault at a bus) a linearisation of the system equations is not permissible. The stability can only be analysed by solving the nonlinear equations with numerical integration. There are also direct methods, which can assess the system stability without explicit solving the differential equations e.g. Lyapunovs second method [7]. But they need many simplifications. Therefore they lose their acceptation for this work.

One aspect of rotor angle stability is that instability also occurs as oscillatory instability. That means, oscillations of rotor angles increase continually, which leads to unstable situations. Therefore long simulation times $t > 20\,\mathrm{s}$ are necessary to detect them. This makes a considerable analysis of a large power system time-consuming.

B. *Proposed method for stability analysis*

In this paper a combination of modal analysis and numerical integration is proposed to keep the simulation time low. The advantages of this method are the simply implementation and the quick computation. In this method the transient simulation is recurrently interrupted within a defined interval (e.g. $\Delta t = 1\,\mathrm{s}$). At these times the eigenvalues are calculated according to the actual system state. The real parts of the eigenvalues represent the damping of the oscillatory modes of the system. A positive real part means negative damping which would lead to a power system instability. From the trend of the real parts of eigenvalues it is possible to draw a conclusion concerning the stability of the actual fault case. The idea of this method is that the analysis of an unstable case continually delivers undamped eigenvalues whereas a stable case shows only damped eigenvalues after a certain simulation time.

A three-phase fault for $t_\mathrm{f} = 0.5\,\mathrm{s}$ at bus 13 and line 02_25 in the original system is simulated as an examples. From the rotor angle oscillations (Fig. 5 and Fig. 7) as well as from the trend of the real parts of the eigenvalues (Fig. 6 and Fig. 8) it can be seen that such a fault at bus 13 is a stable case and at line 02_25 is an unstable case.

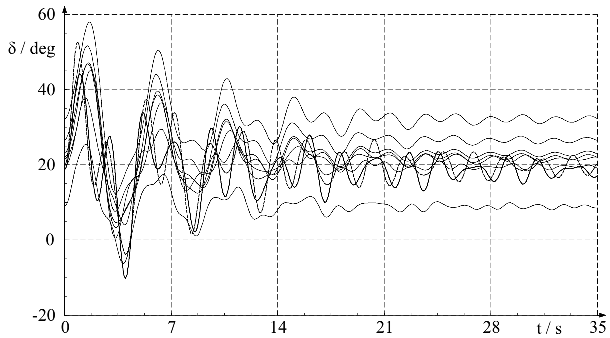

Fig. 5. Rotor angle oscillations, fault at bus 13

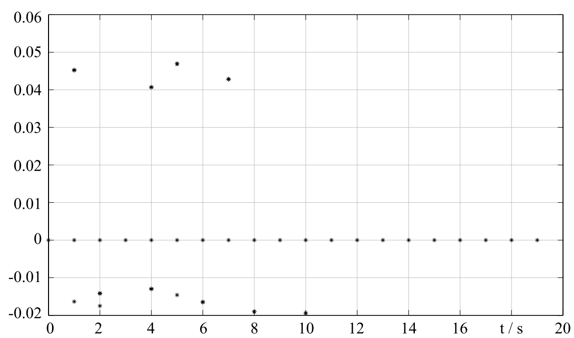

Fig. 6. Trend of eigenvalues, fault at bus 13 – stable case

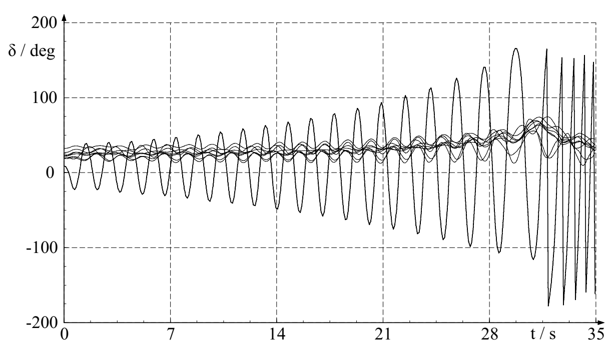

Fig. 7. Rotor angle oscillations, fault at line 02_25

By only analysing the generator rotor angle waveforms it takes longer to decide if the simulated fault case leads to stable or unstable conditions. In Fig. 5 the stable conditions can be found at say $t > 20\,\mathrm{s}$. This decision can be drawn faster by analysing the trend of the real parts of the eigenvalues. In Fig. 6 the system stability can be deduced at say $t > 12\,\mathrm{s}$. The simulation can be stopped much earlier.

The flow chart of the proposed stability analysis method is shown in Fig. 9.

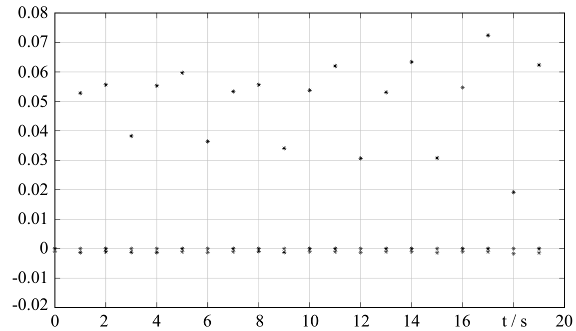

Fig. 8. Trend of eigenvalues, fault at line 02_25 – unstable case

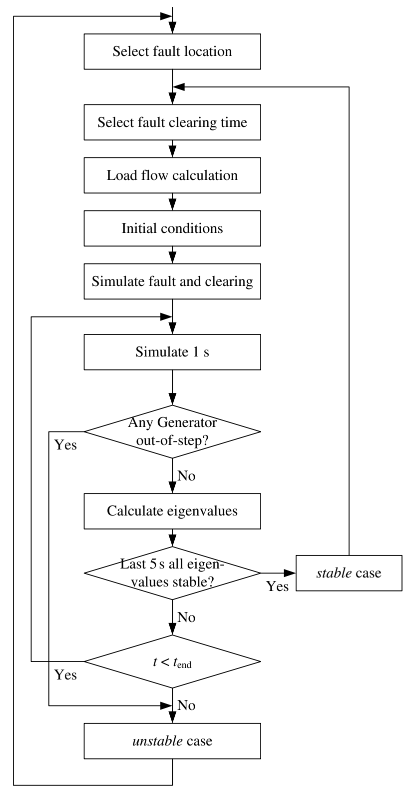

Fig. 9. Flow chart of proposed stability analysis method

After solving the load flow and computation of initial conditions the transient simulation of three-phase faults at specified buses resp. lines with a defined fault clearing time t_f is started. The simulation is interrupted every second and the eigenvalues of the system are calculated. This is done for a defined time period (e.g. $t_\mathrm{end} = 20\,\mathrm{s}$). The real parts of the eigenvalues are evaluated. If all eigenvalues are damped (no positive real part) within a time window of e.g. $5\,\mathrm{s}$ the simulation can be aborted and this case can be assessed as *stable*. Otherwise this case is *unstable*.

IV. Modelling of HVDC connections

In this work 12-pulse bipolar point to point HVDC connections with *current source converters* (CSCs) are considered ($U_\mathrm{d} = \pm 600\,\mathrm{kV}$, $P = 980\,\mathrm{MW}$). Two 6-pulse bridges with integrated transformers are used to model one pole of one converter station [8]. The DC-lines as well as the smoothing reactors and compensation of reactive power at the converters are modelled.

For transient simulations the modelling of controllers for the HVDC converters is necessary. The control concept is direct current control by the rectifier and direct voltage control by the inverter. Due to dynamic requirements a change of this concept has to be possible that is both converters have to be able to control the current and the voltage. Voltage control can be enabled by:

- Extinction angle control or
- Direct voltage control.

If the converter performs extinction angle control, the extinction angle stays at its minimal value. The voltage is rather controlled by the tap changer of the converter transformer. With this control mode the converter has a minimal demand of reactive power. If the converter performs direct voltage control, the extinction angle is slightly higher. This enables the converter to react faster on dynamic voltage changes, but the demand for reactive power is higher. The tap changer of the converter transformer is used to keep the extinction angle at the desired value.

Summarising the converter controller of one pole consist of three independent control loops [8] (Fig. 10):

- Constant current control loop,
- Constant extinction angle control loop and
- Constant voltage control loop.

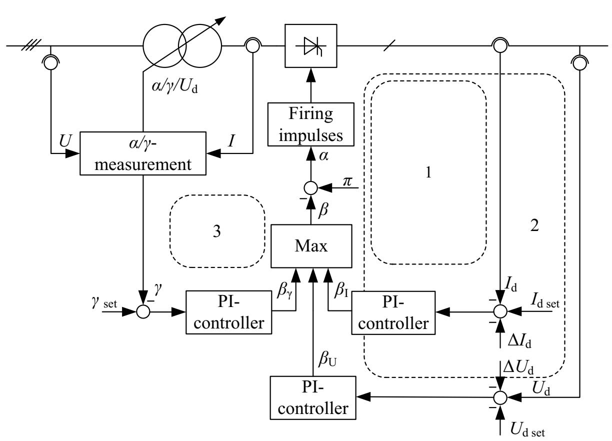

Fig. 10. HVDC control loops

The dynamic change between this three control concepts is enabled by means of a current margin ΔI_d and a voltage margin ΔU_d. A tuning of the control loops is done by limitations of the PI-controllers. Another important feature for an improved dynamic behaviour of the converters is the *voltage dependent current order limit* (VDCOL) [8]. If the voltage at one converter drops, the demand of reactive power at the other converter and hence the risk of commutation failures is increased. This leads to an adverse effect on the stability of the power system. A reduction of the current order in the case of voltage drop counteracts this effect. A regulation of the bridge-transformer tap changers is not modelled due to their slow operation.

In order to verify the implemented control structures simulations with a simple test grid (Fig. 11) are done. Analysed is the behaviour of the HVDC connection when three phase faults with $t_\mathrm{f} = 100\,\mathrm{ms}$ either at the rectifier or the inverter AC-side occur.

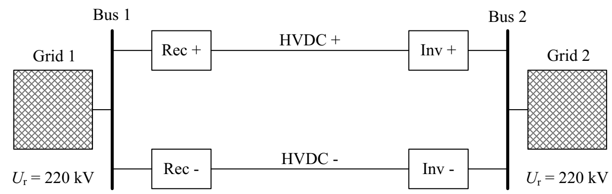

Fig. 11. Test of HVDC connection

A fault at the rectifier AC-side causes a collapse of the AC-voltage as well as the DC-voltage and DC-current. The rectifier tries to increase the DC-current by reducing the firing angle to the lowest value. Nevertheless the inverter changes to current control. Hence the inverter firing angle is reduced. After the fault clearing the voltage and also the current on the DC-line returns immediately. As a result the rectifier changes to current control and limits the DC-current be increasing its firing angle. The inverter takes over voltage control and increases its firing angle again. At the end the rectifier is capable to decrease its firing angle and the HVDC connection returns to normal operation.

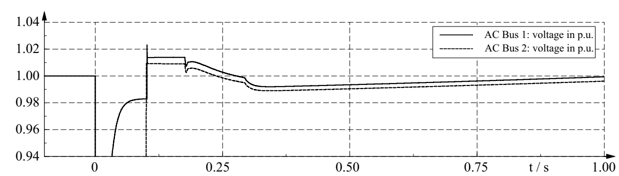

Fig. 12. AC-voltages during fault at inverter AC-side

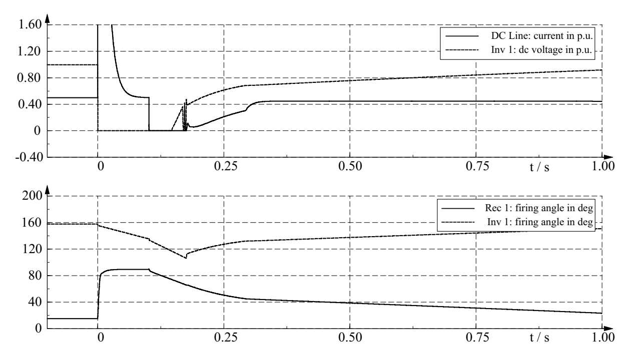

Fig. 13. DC-parameters and firing angles during fault at inverter AC-side

If the fault occurs at the inverter side (Fig. 12 and Fig. 13) the direct current increases immediately. This causes also a short reduction of the AC-voltage at the rectifier. The rectifier increases its firing angle in order to limit the direct current. At a certain firing angle the rectifier changes to voltage control. Due to limitations of the voltage controller the inverter changes to current control. Hence the inverter firing angle is decreased. If the fault is cleared the direct current reduces to zero due to the returning DC-voltage at the inverter. In order to raise the DC-current the inverter firing angle is decreased further. The zero DC-current causes the rectifier to take over current control again. So the rectifier firing angle is reduced. This causes also the inverter to change to voltage control and the HVDC connection returns to normal operation.

In summary it can be said that the HVDC control is working correctly compared to [9] and can be used for the simulations of system stability.

V. Simulation scenarios and results

The following scenarios of the modified IEEE 10 Generator 39 Bus System (Fig. 1) are evaluated:

1) Original grid (only black lines in Fig. 1)
2) Additional HVDC connection from bus 25 to bus 26 (grey solid connection in Fig. 1)
    a) Inverter with constant extinction angle control
    b) Inverter with constant voltage control
3) Replacement of one AC system from bus 25 to bus 26 with a HVDC connection
    a) Inverter with constant extinction angle control
    b) Inverter with constant voltage control
4) Additional AC line from bus 25 to bus 16 (grey dash-dotted connection in Fig. 1)
5) Additional HVDC connection from bus 25 to bus 16 (grey dotted connection in Fig. 1)
    a) Inverter with constant extinction angle control
    b) Inverter with constant voltage control

Simulations with the original power grid show that only faults in the north west of the test system lead to unstable system conditions (see also table I). In all cases problems appear with oscillatory instability that is the rotor angle oscillations are not sufficiently damped. The generators G 08 and G 10 always become unstable first (not shown in table I). That's why all network modifications (scenarios) concentrate on this part of the power grid. One possibility is to bridge the critical line 25_26 with a HVDC connection (scenario 2). In the next step one of the considered two AC systems on the tower could be replaced with a HVDC connection (scenario 3 – doubled impedance of line 25_26). Another possibility is to transport the major part of the active power produced by the generators G 08 and G 10 directly into a load centre, e.g. bus 16. This could be done by an AC-line (scenario 4) or a HVDC connection (scenario 5). There are many other possibilities but the variants had to be limited at this point. In order to analyse the effects of different inverter control strategies (cases a) and b)), the inverter controller is tuned that either only the constant extinction angle control loop or only the constant voltage control loop is in operation.

Simulations of three-phase faults at all buses and all lines (except the DC lines) are carried out and the stability is analysed with the proposed method. The fault clearing time t_f is raised in discrete steps of $\Delta t_\mathrm{f} = 50\,\mathrm{ms}$ in the limits of

$$t_\mathrm{f} = (0.05 \ldots 0.5)\mathrm{s}. \tag{1}$$

Faults at the buses are cleared directly while faults on the lines are cleared by opening the circuit breakers at both sides of the line. Consequently a fault on a line leads to a changed grid topology whereas a fault at a bus only leads to an excitation of rotor oscillations. Opening all circuit breakers at a faulty bus in such a small test system would surely lead to an unstable situation.

TABLE I
System stability of the analysed scenarios compared with the original power grid

Fault location	2a)	2b)	3a)	3b)	4	5a)	5b)
Bus 02	+	+	+	+	+	–	–
Bus 03	+	+	+	+	+	+	–
Bus 25	○	+	–	–	+	–	–
Bus 26	–	–	–	+	+	+	+
Bus 27	–	–	–	n. a.	n. a.	n. a.	n. a.
Bus 30	+	+	+	+	+	–	–
Bus 37	+	+	+	+	+	+	+
Line 02_03	+	+	–	–	+	–	–
Line 02_25	○	○	○	○	○	–	–
Line 25_26	–	–	–	+	+	+	+

System stability: + improved; ○ unchanged; – degraded

Table I shows a comparison of the power system stability between the different scenarios and the original power grid. It can be seen that the HVDC connections in the scenarios 2a), 2b) and 3b) positively affect the system stability. The stability towards the original grid is enhanced which increases the permissible fault clearing time. The scenarios 3a) and 5a) don't degrade the stability. Only the scenario 5b) leads to a degraded system stability. The conclusion is that *a universal statement whether HVDC connections enhances the rotor angle stability of a power system is not possible*. A differentiated view of a grid extension is necessary.

As an example the fault at bus 02 is presented more detailed in Fig. 14. In the original power system a fault clearing time of $t_\mathrm{f} = 0.2\,\mathrm{s}$ leads to an unstable situation. Extending the grid with a HVDC connection from bus 25 to bus 26 the stability can be increased. The rotor angle oscillations for this case are higher damped. But extending the power system network with a HVDC connection from bus 25 to bus 16 the system stability for such a fault is degraded. The rotor angle oscillations are stronger as in the original grid.

In general it can be said that regarding the power system stability the positions of the converters in the grid have to be taken into consideration when HVDC connections shall be built. There are two possible reasons for this conclusion:

- Altered reactions of the AVRs of the generators and/or
- Commutation failures.

Both cases are a result of a changed demand of reactive power when a HVDC system is in parallel operation. The CSCs need reactive power for the processes of commutation. Due to the failures in the grid fast reactions of the HVDC controller are excited resulting in a fast change of the firing angles. This causes a quick change of the reactive power flow which also affects the reactions of the AVRs. They have a major influence on the damping of rotor oscillations. In contrast if the demand for reactive power could not be

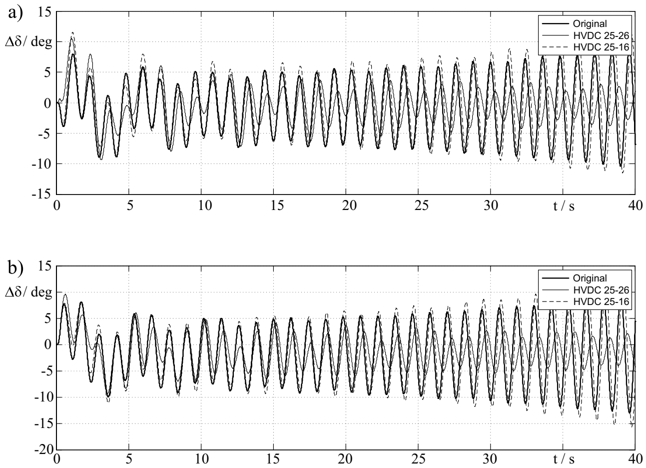

Fig. 14. Comparison of rotor angle oscillations of a) G 08 and b) G 10

satisfied, commutation failures, mostly at the inverter, occur. They have the same effect as a short failure at the converter. Consequently an additional excitation of the rotor oscillations is caused.

The mainly decreased stability for the variant 5b) is caused by the control concept of the inverter. If the inverter is in constant voltage control, its demand of reactive power is increased due to a higher extinction angle. Hence there is a higher risk for commutation failures and therefor a negative influence on the power system stability. More commutation failures can be observed for this variant during the transient simulation. These circumstances could be overcome by several improvements. First the reactive power for the commutation process has to be provided at the converters. All simulations are carried out with compensation of this reactive power. Second there are possibilities to improve the HVDC control. A higher damping of the rotor angle oscillations is possible if the HVDC power transfer depends on the frequency deviations of the AC-grid at both converters. With the use of phasor measurement units (PMUs) and wide area measurements an improved control of the active power flow is imaginable. Third the tuning of PSSs could be improved by taking the whole power grid oscillation modes into consideration. In practice the PSSs are only tuned with respect to the characteristic frequency of the generators. All these improvements will be evaluated in further works.

VI. Conclusion

This paper shows that an expansion of a conventional power grid with HVDC connections could lead to a positive influence on the rotor angle stability. Nevertheless a differentiated view on the expansion measure is necessary. Problems occur, when the grid is not able to satisfy the demand of reactive power. In such cases the appearance of commutation failures and the interactions of HVDC control and AVR of the generators lead to a negative influence on the system stability. But this circumstance could be improved with additional arrangements. Hence, apart from many other advantages, HVDC connections are also able to improve the system stability. Their application for the expansion of power grids should be taken into consideration.

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