12

Power System Stability Controls

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Power system synchronous or angle instability phenomenon limits power transfer, especially where transmission distances are long. This is well recognized and many methods have been developed to improve stability and increase allowable power transfers.

The synchronous stability problem has been fairly well solved by fast fault clearing, thyristor exciters, power system stabilizers (PSSs), and a variety of other stability controls such as generator tripping. Fault clearing of severe short circuits can be less than three cycles (50 ms for 60 Hz frequency) and the effect of the faulted line outage on generator acceleration and stability may be greater than that of the fault itself. The severe multiphase short circuits are infrequent on extra high voltage (EHV) transmission networks.

Nevertheless, more intensive use of available generation and transmission, more onerous load characteristics, greater variation in power schedules, and other negative aspects of industry restructuring pose new concerns. Recent large-scale cascading power failures have heightened the concerns.

In this chapter we describe the state-of-the-art of power system angle stability controls. Controls for voltage stability are described in another chapter and in other literature [1–5].

We emphasize controls employing relatively new technologies that have actually been implemented by electric power companies, or that are seriously being considered for implementation. The technologies include applied control theory, power electronics, microprocessors, signal processing, transducers, and communications.

Power system stability controls must be effective and robust. Effective in an engineering sense means "cost-effective." Control robustness is the capability to operate appropriately for a wide range of power system operating and disturbance conditions.

12.1 Review of Power System Synchronous Stability Basics

Many publications, for example Refs. [6–9,83], describe the basics—which we briefly review here. Power generation is largely by synchronous generators, which are interconnected over thousands of kilometers in very large power systems. Thousands of generators must operate in synchronism during normal and disturbance conditions. Loss of synchronism of a generator or group of generators with respect to another group of generators is *instability* and could result in expensive widespread power blackouts.

The essence of synchronous stability is the balance of individual generator electrical and mechanical torques as described by Newton's second law applied to rotation:

$$J\frac{\mathrm{d}\omega}{\mathrm{d}t} = T_{\mathrm{m}} - T_{\mathrm{e}}$$

where J is moment of inertia of the generator and prime mover, ω is speed, T_{m} is mechanical prime mover torque, and T_{e} is electrical torque related to generator electric power output. The generator speed determines the generator rotor angle changes relative to other generators. Figure 12.1 shows the basic "swing equation" block diagram relationship for a generator connected to a power system.

The conventional equation form and notation are used. The block diagram is explained as follows:

- The inertia constant, H, is proportional to the moment of inertia and is the kinetic energy at rated speed divided by the generator MVA rating. Units are MW-seconds/MVA, or seconds.
- T_{m} is mechanical torque in per unit. As a first approximation it is assumed to be constant. It is, however, influenced by speed controls (governors) and prime mover and energy supply system dynamics.

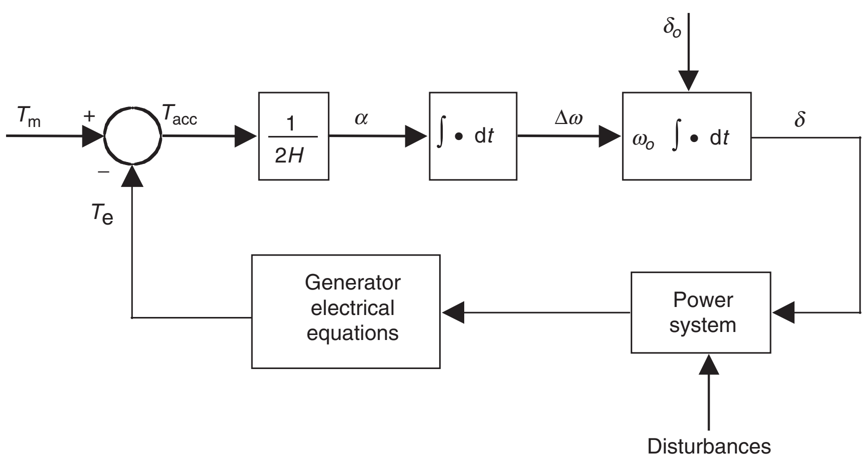

FIGURE 12.1 Block diagram of generator electromechanical dynamics.

- ω_0 is rated frequency in radians/second.
- δ_0 is predisturbance rotor angle in radians relative to a reference generator.
- The power system block comprises the transmission network, loads, power electronic devices, and other generators, prime movers, and energy supply systems with their controls. The transmission network is generally represented by algebraic equations. Loads and generators are represented by algebraic and differential equations.

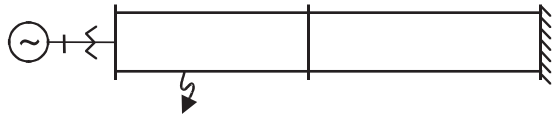

FIGURE 12.2 Remote power plant to large system. Short circuit location is shown.

- Disturbances include short circuits, and line and generator outages. A severe disturbance is a three-phase short circuit near the generator. This causes electric power and torque to be zero, with accelerating torque equal to T_m. (Although generator current is very high for the short circuit, the power factor, and active current and active power are close to zero.) Other switching (discrete) events for stabilization such as line reclosing may be included as disturbances to the differential–algebraic equation model (hybrid DAE math model).
- The generator electrical equations block represents the internal generator dynamics.

Figure 12.2 shows a simple conceptual model: a remote generator connected to a large power system by two parallel transmission lines with an intermediate switching station. With some approximations adequate for a second of time or so following a disturbance, Fig. 12.3 block diagram is realized. The basic relationship between power and torque is $P = T\omega$. Since speed changes are quite small, power is considered equal to torque in per unit. The generator representation is a constant voltage, E', behind a reactance. The transformer and transmission lines are represented by inductive reactances. Using the relation $S = E'I^*$, the generator electrical power is the well-known relation:

$$P_e = \frac{E'V}{X} \sin\delta$$

where V is the large system (infinite bus) voltage and X is the total reactance from the generator internal voltage to the large system. The above equation approximates characteristics of a detailed, large-scale model, and illustrates that the power system is fundamentally a highly nonlinear system for large disturbances.

Figure 12.4a shows the relation graphically. The predisturbance operating point is at the intersection of the load or mechanical power characteristic and the electrical power characteristic. Normal stable operation is at δ_0. For example, a small increase in mechanical power input causes an accelerating power that increases δ to increase P_e until accelerating power returns to zero. The opposite is true for the unstable operating point at $\pi - \delta_0$. δ_0 is normally less than 45°.

During normal operation, mechanical and electrical torques are equal and a generator runs at close to 50 or 60 Hz rated frequency. If, however, a short circuit occurs (usually with removal of a transmission line), the electric power output will be momentarily partially blocked from reaching loads and the generator (or group of generators) will accelerate, with increase in generator speed and angle. If the acceleration relative to other generators is too great, synchronism will be lost. Loss of synchronism is an unstable, runaway situation with large variations of voltages and currents that will normally cause protective separation of a generator or a group

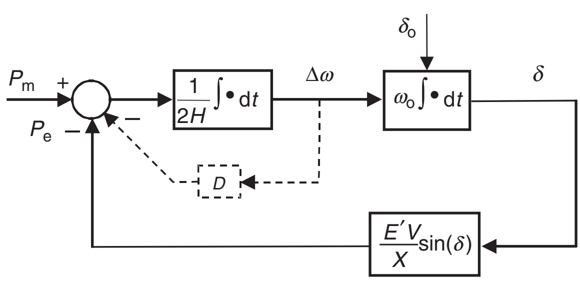

FIGURE 12.3 Simplified block diagram of generator electromechanical dynamics.

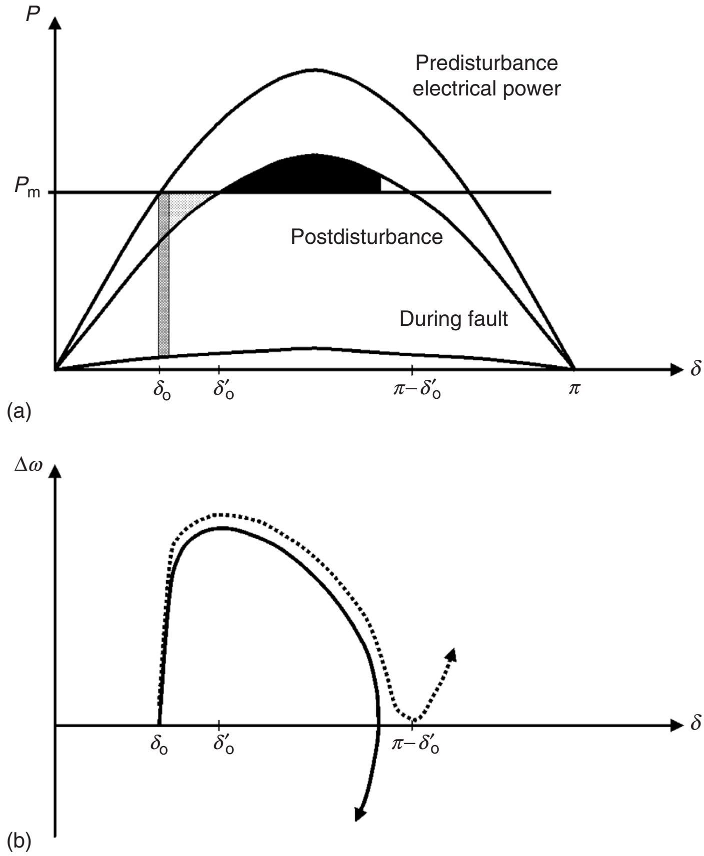

FIGURE 12.4 (a) Power–angle curve and equal area criterion. Dark shading for acceleration energy during fault. Light shading for additional acceleration energy because of line outage. Black shading for deceleration energy. (b) Angle–speed phase plane. Dotted trajectory is for unstable case.

of generators. Following short circuit removal, the electrical torque and power developed as angle increases will decelerate the generator. If deceleration reverses angle swing prior to $\pi - \delta_0'$, stability is maintained at the new operating point δ_0' (Fig. 12.4). If the swing is beyond $\pi - \delta_0'$, accelerating power or torque again becomes positive, resulting in runaway increase in angle and speed, and instability.

Figure 12.4a illustrates the equal area stability criterion for "first swing" stability. If the decelerating area (energy) above the mechanical power load line is greater than the accelerating area below the load line, stability is maintained.

Stability controls increase stability by decreasing the accelerating area or increasing the decelerating area. This may be done by either increasing the electrical power–angle relation, or by decreasing the mechanical power input.

For small disturbances the block diagram, Fig. 12.3, can be linearized. The block diagram would then be that of a second-order differential equation oscillator. For a remote generator connected to a large system the oscillation frequency is 0.8–1.1 Hz.

Figure 12.3 also shows a damping path (dashed, damping power or torque in-phase with speed deviation) that represents mechanical or electrical damping mechanisms in the generator, turbine, loads, and other devices. Mechanical damping arises from the turbine torque–speed characteristic, friction and windage, and components of prime mover control in-phase with speed. At an oscillation frequency, the electrical power can be resolved into a component in-phase with angle (synchronizing power) and a component in quadrature (90° leading) in-phase with speed (damping power). Controls, notably generator automatic voltage regulators with high gain, can introduce negative damping at some oscillation frequencies. (In any feedback control system, high gain combined with time delays can cause positive feedback and instability.) For stability, the net damping must be positive for both normal conditions and for large disturbances with outages. Stability controls may also be added to improve damping. In some cases, stability controls are designed to improve both synchronizing and damping torques of generators.

The above analysis can be generalized to large systems. For first swing stability, synchronous stability between two critical groups of generators is of concern. For damping, many oscillation modes are present, all of which require positive damping. The low frequency modes (0.1–0.8 Hz) are most difficult to damp. These modes represent interarea oscillations between large portions of a power system.

12.2 Concepts of Power System Stability Controls

Figure 12.5 shows the general structure for analysis of power system stability and for development of power system stability controls. The feedback controls are mostly local, continuous controls at power plants. The feedforward controls are discontinuous, and may be local at power plants and substations or wide area.

Stability problems typically involve disturbances such as short circuits, with subsequent removal of faulted elements. Generation or load may be lost, resulting in generation–load imbalance and frequency excursions. These disturbances stimulate power system electromechanical dynamics. Improperly designed or tuned controls may contribute to stability problems; as mentioned, one example is negative damping torques caused by generator automatic voltage regulators.

Because of power system synchronizing and damping forces (including the feedback controls shown in Fig. 12.5), stability is maintained for most disturbances and operating conditions.

12.2.1 Feedback Controls

The most important feedback (closed-loop) controls are the generator excitation controls (automatic voltage regulator often including PSS). Other feedback controls include prime

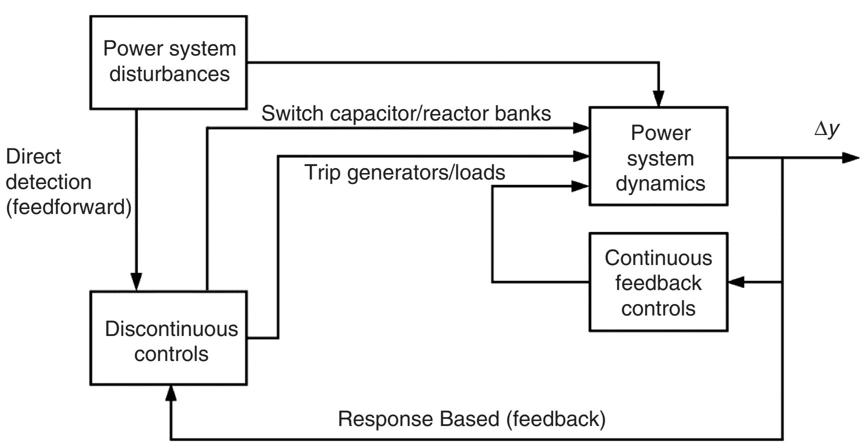

FIGURE 12.5 General power system structure showing local and wide-area, continuous and discontinuous stability controls. (From Taylor, C.W., Erickson, D.C., Martin, K.E., Wilson, R.E., and Venkatasubramanian, V., *Proceedings of the IEEE Special Issue on Energy Infrastructure Defense Systems*, 93, 892, 2005. With permission.)

mover controls, controls for reactive power compensation such as static var systems, and special controls for HVDC links. These controls are generally linear, continuously active, and based on local measurements.

There are, however, interesting possibilities for very effective discontinuous feedback controls, with microprocessors facilitating implementation. Discontinuous controls have certain advantages over continuous controls. Continuous feedback controls are potentially unstable. In complex power systems, continuously controlled equipment may cause adverse modal interactions [10]. Modern digital controls, however, can be discontinuous, and take no action until variables are out-of-range. This is analogous to biological systems (which have evolved over millions of years) that operate on the basis of excitatory stimuli [11].

Bang–bang discontinuous control can operate several times to control large amplitude oscillations, providing time for linear continuous controls to become effective. If stability is a problem, generator excitation control including PSSs should be high performance.

12.2.2 Feedforward Controls

Also shown in Fig. 12.5 are specialized feedforward (open-loop) controls that are powerful stabilizing forces for severe disturbances and for highly stressed operating conditions. Short circuit or outage events can be directly detected to initiate preplanned actions such as generator or load tripping, or reactive power compensation switching. These controls are rule-based, with rules developed from simulations (i.e., pattern recognition). These "event-based" controls are very effective since rapid control action prevents electromechanical dynamics from becoming stability threatening.

"Response-based" or feedback discontinuous controls are also possible. These controls initiate stabilizing actions for arbitrary disturbances that cause significant "swing" of measured variables.

Controls such as generator or load tripping can ensure a postdisturbance equilibrium with sufficient region of attraction. With fast control action the region of attraction can be small compared to requirements with only feedback controls.

Discontinuous controls have been termed discrete supplementary controls [8], special stability controls [12], special protection systems, remedial action schemes, and emergency controls [13]. Discontinuous controls are very powerful. Although the reliability of emergency controls is often an issue [14], adequate reliability can be obtained by design. Generally, controls are required to be as reliable as primary protective relaying. Duplicated or multiple sensors, redundant communications, and duplicated or voting logic are common [15].

Response-based discontinuous controls are often less expensive than event-based controls because fewer sensors and communications paths are needed. These controls are often "one-shot" controls, initiating a single set of switching actions. For slow dynamics, however, the controls can initiate a discontinuous action, observe response, and then initiate additional discontinuous action if necessary.

Undesired operation by some feedforward controls is relatively benign, and controls can be "trigger happy." For example, infrequent misoperation or unnecessary operation of HVDC fast power change, reactive power compensation switching, and transient excitation boosting (TEB) may not be very disruptive. Misoperation of generator tripping (especially of steam-turbine generators), fast valving, load tripping, or controlled separation, however, are disruptive and costly.

12.2.3 Synchronizing and Damping Torques

Power system electromechanical stability means that synchronous generators and motors must remain in synchronism following disturbances—with positive damping of rotor angle oscillations (swings). For very severe disturbances and operating conditions, loss of synchronism (instability) occurs on the first forward swing within about 1 s. For less severe disturbances and operating conditions, instability may occur on the second or subsequent swings because of a combination of insufficient synchronizing and damping torques at synchronous machines.

12.2.4 Effectiveness and Robustness

Power systems have many electromechanical oscillation modes, and each mode can potentially become unstable. Lower frequency interarea modes are the most difficult to stabilize. Controls must be designed to be effective for one or more modes, and must not cause adverse interactions for other modes.

There are recent advances in robust control theory, especially for linear systems. For real nonlinear systems, emphasis should be on knowing uncertainty bounds and on sensitivity analysis using detailed nonlinear, large-scale simulation. For example, the sensitivity of controls to different operating conditions and load characteristics must be studied. On-line simulation using actual operating conditions reduces uncertainty, and can be used for control adaptation.

12.2.5 Actuators

Actuators may be mechanical or power electronic. There are tradeoffs between cost and performance. Mechanical actuators (circuit breakers, turbine valves) are lower cost, and are usually sufficiently fast for electromechanical stability (e.g., two-cycle opening time, five-cycle closing time circuit breakers). They have restricted operating frequency and are generally used for feedforward controls.

Circuit breaker technology and reliability have improved in recent years [16,17]. Bang–bang control (up to perhaps five operations) for interarea oscillations with periods of 2 s or longer is feasible [18]. Traditional controls for mechanical switching have been simple relays, but advanced controls can approach the sophistication of controls of, for example, thyristor-switched capacitor banks.

Power electronic phase control or switching using thyristors has been widely used in generator exciters, HVDC, and static var compensators. Newer devices, such as insulated gate bipolar transistor (IGBT) and gate commutated thyristor (GCT/IGCT), now have voltage and current ratings sufficient for high power transmission applications. Advantages of power electronic actuators are very fast control, unrestricted switching frequency, and minimal transients.

For economy, existing actuators should be used to the extent possible. These include generator excitation and prime mover equipment, HVDC equipment, and circuit breakers. For example, infrequent generator tripping may be cost-effective compared to new power electronic actuated equipment.

12.2.6 Reliability Criteria

Experience shows that instability incidents are usually not caused by three-phase faults near large generating plants that are typically specified in deterministic reliability criteria. Rather they are the result of a combination of unusual failures and circumstances. The three-phase fault reliability criterion is often considered an *umbrella* criterion for less predictable disturbances involving multiple failures such as single-phase short circuits with "sympathetic" tripping of unfaulted lines. Of main concern are multiple *related* failures involving lines on the same right-of-way or with common terminations.

12.3 Types of Power System Stability Controls and Possibilities for Advanced Control

Stability controls are of many types including

- Generator excitation controls
- Prime mover controls including fast valving
- Generator tripping
- Fast fault clearing
- High-speed reclosing and single-pole switching
- Dynamic braking
- Load tripping and modulation
- Reactive power compensation switching or modulation (series and shunt)

- Current injection by voltage source inverter devices (STATCOM, UPFC, SMES, battery storage)
- Fast phase angle control
- HVDC link supplementary controls
- Adjustable speed (doubly fed) synchronous machines
- Controlled separation and underfrequency load shedding

We will summarize these controls. Chapter 17 of Ref. [7] provides considerable additional information. Reference [19] describes use of many of these controls in Japan.

12.3.1 Excitation Control

Generator excitation controls are a basic stability control. Thyristor exciters with high ceiling voltage provide powerful and economical means to ensure stability for large disturbances. Modern automatic voltage regulators and PSSs are digital, facilitating additional capabilities such as adaptive control and special logic [20–23].

Excitation control is almost always based on local measurements. Therefore full effectiveness may not be obtained for interarea stability problems where the normal local measurements are not sufficient. Line drop compensation [24,25] is one method to increase the effectiveness (sensitivity) of excitation control, and improve coordination with static var compensators that normally control transmission voltage with small droop.

Several forms of discontinuous control have been applied to keep field voltage near ceiling levels during the first forward interarea swing [7,26,27]. The control described in Refs. [7,26] computes change in rotor angle locally from the PSS speed change signal. The control described in Ref. [27] is a feedforward control that injects a decaying pulse into the voltage regulators at a large power plant following remote direct detection of a large disturbance. Figure 12.6 shows simulation results using this TEB.

12.3.2 Prime Mover Control Including Fast Valving

Fast power reduction (fast valving) at accelerating sending-end generators is an effective means of stability improvement. Use has been limited, however, because of the coordination required between characteristics of the electrical power system, the prime mover and prime mover controls, and the energy supply system (boiler).

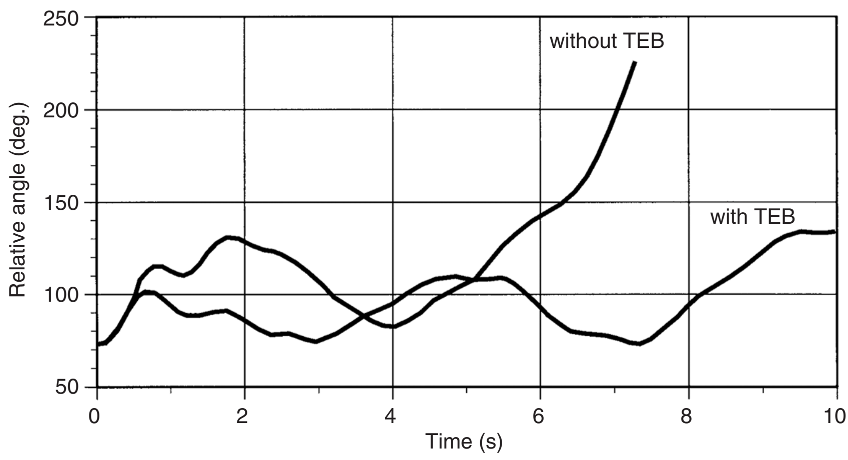

FIGURE 12.6 Rotor angle swing of Grand Coulee Unit 19 in Pacific Northwest relative to the San Onofre nuclear plant in Southern California. The effect of transient excitation boosting (TEB) at the Grand Coulee Third Power Plant following bipolar outage of the Pacific HVDC Intertie (3100 MW) is shown. (From Taylor, C.W., Mechenbier, J.R., and Matthews, C.E., *IEEE Transactions on Power Systems*, 8, 1291, 1993.)

Digital prime mover controls facilitate addition of special features for stability enhancement. Digital boiler controls, often retrofitted on existing equipment, may improve the feasibility of fast valving.

Fast valving is potentially lower cost than tripping of turbo-generators. References [7,28] describe concepts, investigations, and recent implementations of fast valving. Two methods of steam-turbine fast valving are used: momentary and sustained. In momentary fast valving, the reheat turbine intercept valves are rapidly closed and then reopened after a short time delay. In sustained fast valving, the intercept values are also rapidly opened and reclosed, but with the control valves partially closed for sustained power reduction. Sustained fast valving may be necessary for a stable post-disturbance equilibrium.

12.3.3 Generator Tripping

Generator tripping is an effective (cost-effective) control especially if hydro units are used. Tripping of fossil units, especially gas- or oil-fired units, may be attractive if tripping to house load is possible and reliable. Gas turbine and combined-cycle plants constitute a large percentage of the new generation. Occasional tripping of these units is feasible and can become an attractive stability control in the future.

Most generator tripping controls are event-based (based on outage of generating plant out going lines or outage of tie lines). Several advanced response-based generator tripping controls, however, have been implemented.

The automatic trend relay (ATR) is implemented at the Colstrip generating plant in eastern Montana [29]. The plant consists of two 330-MW units and two 700-MW units. The microprocessor-based controller measures rotor speed and generator power and computes acceleration and angle. Tripping of 16–100% of plant generation is based on 11 trip algorithms involving acceleration, speed, and angle changes. Because of the long distance to Pacific Northwest load centers, the ATR has operated many times, both desirably and undesirably. There are proposals to use voltage angle measurement information (Colstrip 500-kV voltage angle relative to Grand Coulee and other Northwest locations) to adaptively adjust ATR settings, or as additional information for trip algorithms. Another possibility is to provide speed or frequency measurements from Grand Coulee and other locations to base algorithms on speed difference rather than only Colstrip speed [30].

A Tokyo Electric Power Company stabilizing control predicts generator angle changes and decides the minimum number of generators to trip [31]. Local generator electric power, voltage, and current measurements are used to estimate angles. The control has worked correctly for several actual disturbances.

The Tokyo Electric Power Company is also developing an emergency control system, which uses a predictive prevention method for step-out of pumped storage generators [32,33]. In the new method, the generators in TEPCO's network that swing against their local pumped storage generators after serious faults are treated as an external power system. The parameters in the external system, such as angle and moment of inertia, are estimated using local on-line information, and the behavior of local pumped storage generators is predicted based on equations of motion. Control actions (the number of generators to be tripped) are determined based on the prediction.

Reference [34] describes response-based generator tripping using a phase-plane controller. The controller is based on the apparent resistance–rate of change of apparent resistance (*R*–*R*dot) phase plane, which is closely related to an angle difference–speed difference phase plane between two areas. The primary use of the controller is for controlled separation of the Pacific AC Intertie. Figure 12.7 shows simulation results where 600 MW of generator tripping reduces the likelihood of controlled separation.

12.3.4 Fast Fault Clearing, High-Speed Reclosing, and Single-Pole Switching

Clearing time of close-in faults can be less than three cycles using conventional protective relays and circuit breakers. Typical EHV circuit breakers have two-cycle opening time. One-cycle breakers have

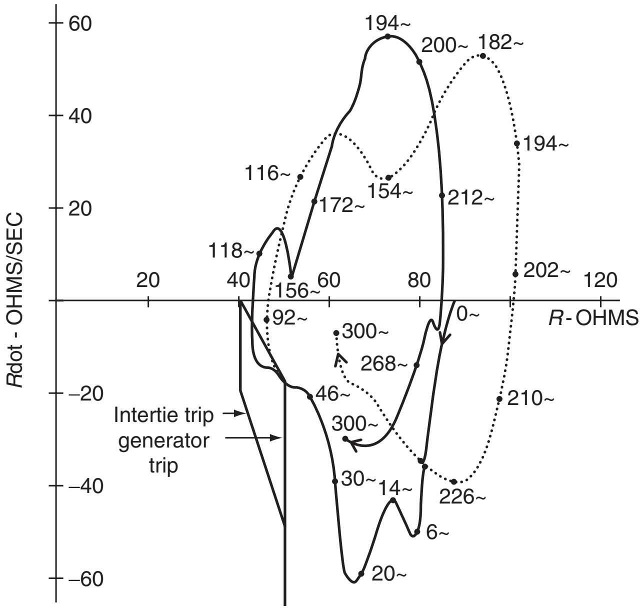

FIGURE 12.7 *R–R*dot phase plane for loss of Pacific HVDC Intertie (2000 MW). Solid trajectory is without additional generator tripping. Dashed trajectory is with additional 600 MW of generator tripping initiated by the *R–R*dot controller generator trip switching line. (From Haner, J.M., Laughlin, T.D., and Taylor, C.W., *IEEE Transactions on Power Delivery*, PWRD-1, 35, 1986.)

been developed [35], but special breakers are seldom justified. High magnitude short circuits may be detected as fast as one-fourth cycle by nondirectional overcurrent relays. Ultrahigh speed traveling wave relays are also available [36]. With such short clearing times, and considering that most EHV faults are single-phase, the removed transmission lines or other elements may be the major contributor to generator acceleration. This is especially true if non-faulted equipment is also removed by sympathetic relaying.

High-speed reclosing is an effective method of improving stability and reliability. Reclosing is before the maximum of the first forward angular swing, but after 30–40 cycle time for arc extinction. During a lightning storm, high-speed reclosing keeps the maximum number of lines in service. High-speed reclosing is effective when unfaulted lines trip because of relay misoperations.

Unsuccessful high-speed reclosing into a permanent fault can cause instability, and can also compound the torsional duty imposed on turbine-generator shafts. Solutions include reclosing only for single-phase faults, and reclosing from the weaker remote end with hot-line checking prior to reclosing at the generator end. Communication signals from the weaker end indicating successful reclosing can also be used to enable reclosing at the generator end [37].

Single-pole switching is a practical means to improve stability and reliability in extra high voltage networks where most circuit breakers have independent pole operation [38,39]. Several methods are used to ensure secondary arc extinction. For short lines, no special methods are needed. For long lines, the four-reactor scheme [40,41] is most commonly used. High-speed grounding switches may be used [42]. A hybrid reclosing method used successfully by Bonneville Power Administration (BPA) on many lines over many years employs single-pole tripping, but with three-pole tripping on the backswing followed by rapid three-pole reclosure; the three-pole tripping ensures secondary arc extinction [38]. Single-pole switching may necessitate positive sequence filtering in stability control input signals.

For advanced stability control, signal processing and pattern recognition techniques may be developed to detect secondary arc extinction [43,44]. Reclosing into a fault is avoided and single-pole reclosing success is improved.

High-speed reclosing or single-pole switching may not allow increased power transfers because deterministic reliability criteria generally specify permanent faults. Nevertheless, fast reclosing provides "defense-in-depth" for frequently occurring single-phase temporary faults and false operation of protective relays. The probability of power failures because of multiple line outages is greatly reduced.

12.3.5 Dynamic Braking

Shunt dynamic brakes using mechanical switching have been used infrequently [7]. Normally the insertion time of a few hundred milliseconds is fixed. One attractive method not requiring switching is neutral-to-ground resistors in generator step-up transformers; braking automatically results for ground faults—which are most common. Often, generator tripping, which helps ensure a postdisturbance equilibrium, is a better solution.

Thyristor switching of dynamic brakes has been proposed. Thyristor switching or phase control minimizes generator torsional duty [45], and can also be a subsynchronous resonance countermeasure [46].

12.3.6 Load Tripping and Modulation

Load tripping is similar in concept to generator tripping but is at the receiving end to reduce deceleration of receiving-end generation. Interruptible industrial load is commonly used. For example, Ref. [47] describes tripping of up to 3000 MW of industrial load following outages during power import conditions.

Rather than tripping large blocks of industrial load, it may be possible to trip low priority commercial and residential load such as space and water heaters, or air conditioners. This is less disruptive and the consumer may not even notice brief interruptions. The feasibility of this control depends on implementation of direct load control as part of demand side management and on the installation of high-speed communication links to consumers with high-speed actuators at load devices. Although unlikely because of economics, appliances such as heaters could be designed to provide frequency sensitivity by local measurements.

Load tripping is also used for voltage stability. Here the communication and actuator speeds are generally not as critical. It is also possible to modulate loads such as heaters to damp oscillations [48–50]. Clearly load tripping or modulation of small loads will depend on the economics, and the development of fast communications and actuators.

12.3.7 Reactive Power Compensation Switching or Modulation

Controlled series or shunt compensation improves stability, with series compensation generally being the most powerful. For switched compensation, either mechanical or power electronic switches may be used. For continuous modulation, thyristor phase control of a reactor (TCR) is used. Mechanical switching has the advantage of lower cost. The operating times of circuit breakers are usually adequate, especially for interarea oscillations. Mechanical switching is generally single insertion of compensation for synchronizing support. In addition to previously mentioned advantages, power electronic control has advantages in subsynchronous resonance performance.

For synchronizing support, high-speed series capacitor switching has been used effectively on the North American Pacific AC Intertie for over 25 years [51]. The main application is for full or partial outages of the parallel Pacific HVDC Intertie (event-driven control using transfer trip over microwave radio). Series capacitors are inserted by circuit breaker opening; operators bypass the series capacitors some minutes after the event. Response-based control using an impedance relay was also used for some years, and new response-based controls are being investigated.

Thyristor-based series compensation switching or modulation has been developed with several installations in service or planned [52,53,32]. Thyristor-controlled series compensation (TCSC) allows significant time–current dependent increase in series reactance over nominal reactance. With appropriate controls, this increase in reactance can be a powerful stabilizing force.

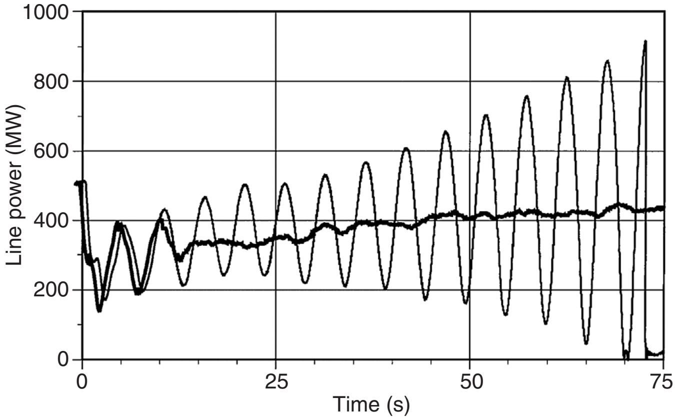

FIGURE 12.8 Effect of TCSCs for trip of a 300-MW generator in the North–Northeast Brazilian network. Results are from commissioning field tests in March 1999. The thin line without TCSC power oscillation damping shows interconnection separation after 70 s. The thick line with TCSC power oscillation damping shows rapid oscillation damping.

Thyristor-controlled series compensation was chosen for the 1020-km, 500-kV intertie between the Brazilian North–Northeast networks and the Southeast network [54]. The TCSCs at each end of the intertie are modulated using line power measurements to damp low frequency (0.12 Hz) oscillations. Figure 12.8, from commissioning field tests [55], shows the powerful stabilizing benefits of TCSCs.

Reference [56] describes a TCSC application in China for integration of a remote power plant using two parallel 500-kV transmission lines (1300 km). Transient stability simulations indicate that 25% thyristor-controlled compensation is more effective than 45% fixed compensation. Several advanced TCSC control techniques are promising. The state-of-the-art is to provide both transient stability and damping control modes. Reference [57] surveys TCSC stability controls, providing 85 references.

For synchronizing support, high-speed switching of shunt capacitor banks is also effective. Again on the Pacific AC Intertie, four 200-MVAr shunt banks are switched for HVDC and 500-kV ac line outages [18]. These banks plus other 500-kV shunt capacitor/reactor banks and series capacitors are also switched for severe voltage swings.

High-speed mechanical switching of shunt banks as part of a static var system is common. For example, the Forbes SVS near Duluth, Minnesota, USA, includes two 300-MVAr 500-kV shunt capacitor banks [58]. Generally it is effective to augment power electronic controlled compensation with fixed or mechanically switched compensation.

Static var compensators are applied along interconnections to improve synchronizing and damping support. Voltage support at intermediate points allows operation at angles above 90°. SVCs are modulated to improve oscillation damping. A seminal study [6,59] showed line current magnitude to be the most effective input signal. Synchronous condensers can provide similar benefits, but nowadays are not competitive with power electronic control. Available SVCs in load areas may be used to indirectly modulate load to provide synchronizing or damping forces.

Digital control facilitates new strategies. Adaptive control—gain supervision and optimization—is common. For series or shunt power electronic devices, control mode selection allows bang–bang control, synchronizing versus damping control, and other nonlinear and adaptive strategies.

12.3.8 Current Injection by Voltage Sourced Inverters

Advanced power electronic controlled equipment employs gate turn-off thyristors, IGCTs, or IGBTs. Reference [6] describes use of these devices for oscillation damping. As with conventional thyristor-based equipment, it is often effective for voltage source inverter control to also direct mechanical switching.

Voltage sourced inverters may also be used for real power series or shunt injection. Superconducting magnetic energy storage (SMES) or battery storage is the most common. For angle stability control, injection of real power is more effective than reactive power. For transient stability improvement, SMES can be of smaller MVA size and lower cost than a STATCOM. SMES is less location dependent than a STATCOM.

12.3.9 Fast Voltage Phase Angle Control

Voltage phase angles and thereby rotor angles can be directly and rapidly controlled by voltage sourced inverter series injection or by power electronic controlled phase shifting transformers. This provides powerful stability control. Although one type of thyristor-controlled phase shifting transformer was developed over 20 years ago [60], high cost has presumably prevented installations. Reference [61] describes an application study.

As modular devices, multiple voltage sourced converters can be combined in several shunt and series arrangements, and as back-to-back HVDC links. Reactive power injection devices include the shunt static compensator (STATCOM), static synchronous series compensator (SSSC), unified power flow controller (UPFC), and interline power flow controller (IPFC). The convertible static compensator (CSC) allows multiple configurations with one installation in service. These devices tend to be quite expensive and special purpose.

The UPFC combines shunt and series voltage sourced converters with common dc capacitor and controls, and provides shunt compensation, series compensation, and phase shifting transformer functions. At least one installation (not a transient stability application) is in service [62], along with a CSC installation [9].

One concept employs power electronic series or phase shifting equipment to control angles across an interconnection within a small range [63]. On a power–angle curve, this can be visualized as keeping high synchronizing coefficient (slope of power–angle curve) during disturbances.

BPA developed a novel method for transient stability by high-speed 120° phase rotation of transmission lines between networks losing synchronism [64]. This technique is very powerful (perhaps too powerful) and raises reliability and robustness issues especially in the usual case where several lines form the interconnection. It has not been implemented.

12.3.10 HVDC Link Supplementary Controls

HVDC links are installed for power transfer reasons. In contrast to the above power electronic devices, the available HVDC converters provide the actuators so that stability control is inexpensive. For long distance HVDC links within a synchronous network, HVDC modulation can provide powerful stabilization, with active and reactive power injections at each converter. Control robustness, however, is a concern [6,10].

References [6,65–67] describe HVDC link stability controls. The Pacific HVDC Intertie modulation control implemented in 1976 is unique in that a remote (wide-area) input signal from the parallel Pacific AC Intertie was used [66,67]. Figure 12.9 shows commissioning test results.

12.3.11 Adjustable Speed (Doubly Fed) Synchronous Machines

Reference [68] summarizes stability benefits of adjustable speed synchronous machines that have been developed for pumped storage applications in Japan. Fast digital control of excitation frequency enables direct control of rotor angle.

12.3.12 Controlled Separation and Underfrequency Load Shedding

For very severe disturbances and failures, maintaining synchronism may not be possible or cost-effective. Controlled separation based on out-of-step detection or parallel path outages mitigates the effects of

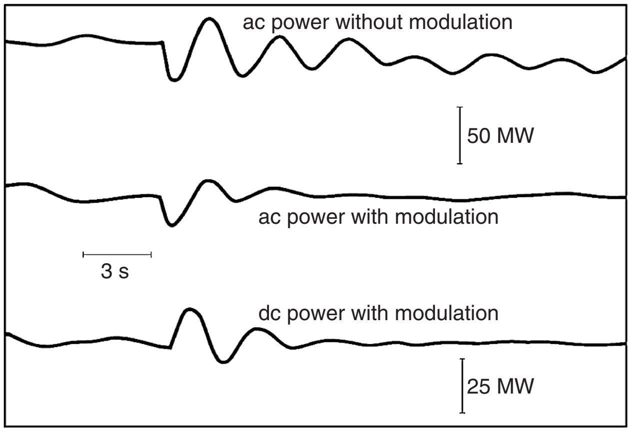

FIGURE 12.9 System response to Pacific AC Intertie series capacitor bypass with and without dc modulation. (From Cresap, R.L., Scott, D.N., Mittelstadt, W.A., and Taylor, C.W., *IEEE Transactions on Power Apparatus and Systems*, PAS-98, 1053, 1978.)

instability. Stable islands are formed, but underfrequency load shedding may be required in islands that were importing power.

References [34,69–71] describe advanced controlled separation schemes. Recent proposals advocate use of voltage phase angle measurements for controlled separation.

12.4 Dynamic Security Assessment

Control design and settings, along with transfer limits, are usually based on off-line simulation (time and frequency domain) and on field tests. Controls must then operate appropriately for a variety of operating conditions and disturbances.

Recently, however, on-line dynamic (or transient) stability and security assessment software have been developed. State estimation and on-line power flow provide the base operating conditions. Simulation of potential disturbances is then based on actual operating conditions, reducing uncertainty of the control environment. Dynamic security assessment is presently used to determine arming levels for generator tripping controls [72,73].

With today's computer capabilities, hundreds or thousands of large-scale simulations may be run each day to provide an organized database of system stability properties. Security assessment is made efficient by techniques such as fast screening and contingency selection, and smart termination of strongly stable or unstable cases. Parallel computation is straightforward using multiple workstations for different simulation cases; common initiation may be used for the different contingencies.

In the future, dynamic security assessment may be used for control adaptation to current operating conditions. Another possibility is stability control based on neural network or decision-tree pattern recognition. Dynamic security assessment provides the database for pattern recognition techniques. Pattern recognition may be considered data compression of security assessment results.

Industry restructuring requiring near real-time power transfer capability determination may accelerate the implementation of dynamic security assessment, facilitating advanced stability controls.

12.5 "Intelligent" Controls

Mention has already been made of rule-based controls and pattern recognition based controls. As a possibility, Ref. [74] describes a sophisticated self-organizing neural fuzzy controller (SONFC) based on the speed–acceleration phase plane. Compared to the angle–speed phase plane, control tends to be faster and both final states are zero (using angle, the postdisturbance equilibrium angle is not known in advance). The controllers are located at generator plants. Acceleration and speed can be easily measured or computed using, for example, the techniques developed for PSSs.

The SONFC could be expanded to incorporate remote measurements. Dynamic security assessment simulations could be used for updating or retraining of the neural network fuzzy controller. The SONFC is suitable for generator tripping, series or shunt capacitor switching, HVDC control, etc.

12.6 Wide-Area Stability Controls

The development of synchronized phasor measurements, fiber optic communications, digital controllers, and other IT advances have spurred development of wide-area controls. Wide-area controls offer increased observability and controllability, and as mentioned above, may be either continuous or discontinuous. They may augment local controls, or provide supervisory or adaptive functions rather than primary control. In particular, voltage phase angles, related to generator rotor angles, are often advocated as input signals.

The additional time delays because of communications are a concern, and increase the potential for adverse dynamic interactions. Figure 12.10, however, shows that latency for fiber optic communications (SONET) can be less than 25 ms, which is adequate for interarea stability.

Wide-area continuous controls include PSSs applied to generator automatic voltage regulators, and to static var compensators and other power electronic devices. For some power systems, wide-area controls are technically more effective than local controls [75,76].

Referring to Fig. 12.5, discontinuous controls are often wide-area. Control inputs can be from multiple locations and control output actions can be taken at multiple locations. Most wide-area discontinuous controls directly detect fault or outage events (feedforward control). These controls generally involve preplanned binary logic rules and employ programmable logic controllers. For example, if line A and line B trip, then disconnect sending-end generators at power plants C and D. These schemes can be quite complex—BPA's remedial action scheme for the Pacific AC Intertie comprises around 1000 AND/OR decisions, with fault tolerant logic computers at two control centers.

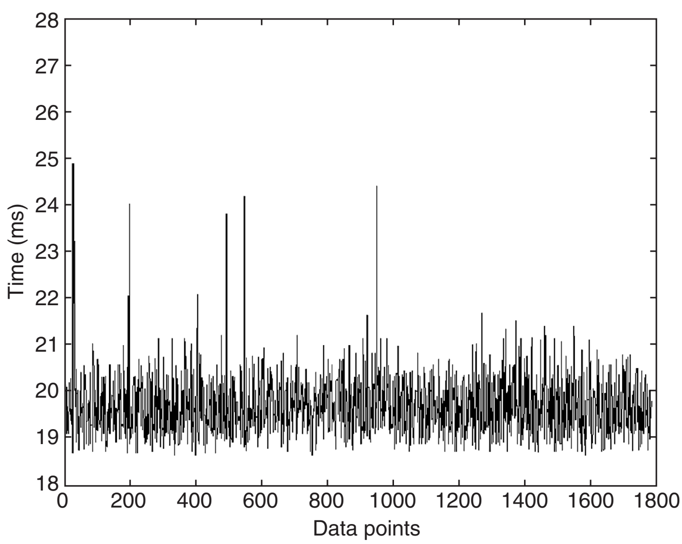

FIGURE 12.10 Fiber optic communications latency over 1 min. Bonneville Power Administration phasor measurement unit at Slatt Substation to BPA control center. (From Taylor, C.W., Erickson, D.C., Martin, K.E., Wilson, R.E., and Venkatasubramanian, V., *Proceedings of the IEEE Special Issue on Energy Infrastructure Defense Systems*, 93, 892, 2005. With permission.)

BPA is developing a feedback wide-area stability and voltage control system (WACS) employing discontinuous control actions [77]. Inputs are from phasor measurements at eight locations, with generator tripping and capacitor or reactor switching actions available at many locations via existing remedial action scheme circuits. The WACS controller has two algorithms that cater to both angle and voltage stability problems.

12.7 Effect of Industry Restructuring on Stability Controls

Industry restructuring has many impacts on power system stability. Frequently changing power transfer patterns cause new stability problems. Most stability and transfer capability problems must be solved by new controls and new substation equipment, rather than by new transmission lines.

Different ownership of generation, transmission, and distribution makes the necessary power system engineering more difficult. New power industry reliability standards along with ancillary services mechanisms are being developed. Generator or load tripping, fast valving, higher than standard exciter ceilings, and PSSs may be ancillary services. In large interconnections, independent grid operators or reliability coordination centers may facilitate dynamic security assessment and centralized stability controls.

12.8 Experience from Recent Power Failures

Recent cascading power outages demonstrated the impact of control and protection failures, the need for "defense-in-depth," and the need for advanced stability controls.

The July 2, 1996 and August 10, 1996 power failures [78–81] in western North America, the August 14, 2003 failure in northeastern North America [82], and other failures demonstrate need for improvements and innovations in stability control areas such as

- Fast insertion of reactive power compensation, and fast generator tripping using response-based controls
- Special HVDC and SVC control
- PSS design and tuning
- Controlled separation
- Power system modeling and data validation for control design
- Adaptation of controls to actual operating conditions
- Local or wide-area automatic load shedding
- Prioritized upgrade of control and protection equipment including generator excitation equipment

12.9 Summary

Power system angle stability can be improved by a wide variety of controls. Some methods have been used effectively for many years, both at generating plants and in transmission networks. New control techniques and actuating equipment are promising.

We provide a broad survey of available stability control techniques with emphasis on implemented controls, and on new and emerging technology.

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