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POWER SYSTEM TRANSIENTS

The purpose of this article is to summarize briefly the dynamics, stability, and control of large interconnected electric systems by a practical case analysis. The reader is referred to the many journal papers, that appear in various IEEE Transactions. For more detailed mathematical studies and computer simulations, see the bibliography at the end of this article. The article also analyzes a major outage that occurred on the western North American interconnection.

Economical and environmental considerations promote the interconnection of power transmission systems when a load can be served from a generation station thousands of miles away. Modern power systems are highly interconnected. As an example, the Western Systems Coordinating Council (*WSCC*) system stretches from northern Canada to Mexico and from the eastern Rocky Mountains to the Pacific Ocean. The essential component of a power system is a synchronous generator. All generators connected to the power transmission network must be synchronized, that is, operate at the same electric frequency as the network. Synchronized operation of generators in large interconnected systems represents a greater challenge. One of the major concerns is transient stability which is related to the capability of generators to retain synchronism following a power system disturbance (1).

A large interconnected power system is subject to a wide variety of disturbances. Typical disturbances include short circuit (fault) conditions (phase-to-ground, phase-to-phase, three-phase, etc.), load switching, and outages of different system components, such as transmission lines, transformers, and generators. Following a disturbance, the system experiences transient conditions. When considering transient stability problems, we refer to large electromechanical transients involving the rotor dynamics of synchronous generators. From a generator standpoint, a disturbance results in power imbalance between the generator's electric power output and the mechanical power input from a prime mover. If a generator has an excess of mechanical power input, its rotor accelerates. If a generator has an excess of electric load, it slows down. If the system has sufficient synchronizing power, the generators retain synchronism, and the system reaches postdisturbance steady-state conditions.

The first condition necessary for the system to be transiently stable is the existence of the postdisturbance steady-state. Postdisturbance system conditions are generally different from predisturbance conditions because of the loss of transmission lines, generation, and load during the disturbance.

Synchronizing power is affected by transmission system conditions, generating patterns, generator controls, and load characteristics. Transmission line outages caused by system disturbances increase electrical impedance and decrease transfer capability between sending and receiving areas. This reduces the synchronizing power and the stability margin in the system. Generating patterns characterized by large power flows over long distances also reduce synchronizing power. A good indicator of the synchronizing power in the system is the relative phase angle between voltages in sending and receiving areas.

Synchronous generators are equipped with automatic voltage regulators which control the excitation voltage. These controls are feedback type with the objective of keeping the generator terminal ac voltage at a desired set point. Automatic voltage regulators improve synchronizing power during transient conditions (2). The controls may cause instability, however, by introducing negatively damped oscillations in the system. The amount of negative damping depends on the transmission system conditions and loading. A good indicator of generator susceptibility to negative damping is the change in the generator terminal voltage with respect to the change in the generator rotor angle (2). Negative damping is more likely to develop under stressed system conditions, when certain transmission lines are lost (longer electrical distances between generators) and under heavy power transfers. The phase angle between voltages at the sending and receiving ends of the transmission is a good indicator of the system stress and the amount of synchronizing and damping power. As a disturbance weakens system conditions (line outages), the system damping power decreases and negatively damped oscillations develop.

Transient and Dynamic Stability Enhancement

This section describes control actions that can be taken to improve transient stability and to implement these controls in power systems. There are three fundamental components of a power system: generation, transmission, and load. Therefore, there are three options to improve the transient and dynamic stability. Basic concepts for improving system stability can be found in (2,3).

Generator Controls.

Power System Stabilizers. A power system stabilizer (*PSS*) is a supplementary control which injects signals into the generator excitation system to introduce positive damping torque on the rotor. Conventional PSS uses generator frequency as input, filtered by a washout filter to remove low frequency variations. Newer PSS designs are dual input, where electrical frequency and electric power are used to synthesize generator accelerating power (4). Next, the input signals are passed through a stage of lead-lag blocks to create a required phase shift in the output signal. PSS output is added to the voltage regulator input. Concepts of PSS design, tuning, and application are presented in (5). The PSS has a significant effect on the damping performance of power systems. In the WSCC system, PSS's are required for generators whose power output is greater than 50 MW.

Transient Stability Excitation Control. A transient stability excitation control and a transient excitation booster (6,7,8) inject a signal into the generator excitation system to introduce synchronizing torque on the rotor. These are emergency and therefore discontinuous controls which operate when a critical disturbance is detected in the system. The closed-loop control used by Ontario Hydro at several generators is presented in (6). Following local detection of a disturbance, a signal proportional to the rotor angle is applied to the voltage regulator. Open-loop control is used by the Bonneville Power Administration at the Grand Coulee power plant (7,8). Using telemetry of a critical outage, a predetermined decaying pulse is injected into the generator's excitation system. The control action temporarily raises the ac voltage thereby increasing transfer capability and increasing the power consumption of voltage-sensitive loads in the sending area. These types of controls are effective for generators with powerful excitation systems.

Generation-Dropping Controls. Dropping generation in the area with power excess is a proven method for improving transient stability. Most of the generator-dropping schemes in service today are event-driven control actions. These controls are initiated by detection of the transmission line outages and drop predetermined amounts of generation. These controls are armed by a system operator on the basis of the system power flows.

Montana Power Company uses advanced, response-based, generator-dropping controls (acceleration trend relay) to ensure transient stability of the interconnection between Montana and the Pacific Northwest during high power transfer levels (9). The relay trip decisions are based on local measurements at the Colstrip power plant. The inputs are mechanical speed and electric power for each generator. These signals are processed further to compute the Colstrip plant center-of-inertia speed, angle deviation from the predisturbance equilibrium, and acceleration, which are used by the ATR logic to issue generation trip orders.

Transmission Network Devices.

Series Compensation. Switched series compensation is a proven method of improving system stability (10,11). Series capacitors reduce equivalent line impedance, thereby increasing line transfer capability.

Mechanically switched series capacitors are used at the Pacific AC Intertie to improve voltage and transient stability. The BPA has developed and implemented a control scheme which provides fast insertion of series capacitors in all three intertie lines at the Fort Rock substation for low ac voltage conditions.

Thyristor-controlled series compensators (*TCSC*) provide transient stability benefits similar to mechanically switched capacitors (12,13). In addition, the TCSC allows better utilization of the capacitor time-overload capabilities, therefore providing capability to boost the TCSC effective reactance above its continuous rating for a short time. This can be used to improve transient stability (14,15).

TCSC capability to regulate the device effective impedance continuously makes the device useful for power system damping applications. By varying line impedance, a TCSC can introduce damping torques (12,14).

A static synchronous series compensator (*SSSC*) has been developed and can be used in similar applications (16). It represents a synchronous voltage source connected in series with a transmission line and is based entirely on power electronics converter technology.

Shunt Compensation. Conventional shunt compensators include mechanically switched shunt capacitors and reactors, thyristor-switched capacitors, and thyristor-controlled reactors. Mechanically switched shunt capacitors are widely used to improve voltage and synchronous stability. The Bonneville Power Administration uses fast insertion of shunt capacitors to improve the transient stability of the Pacific AC Intertie.

A combination of several thyristor-controlled shunt devices forms a static var compensator (*SVC*). A thyristor-controlled reactor can vary its admittance continuously in its control range. Thyristor-switched capacitors provide fast and repeatable switching. SVCs are often utilized for damping power oscillation and voltage control (17), when fast responses and continuous responses are required.

A static compensator (*Statcom*) has been developed and demonstrated (18). Statcom offers superior control capabilities compared with SVCs in lower voltage ranges and employs power electronics technology.

Dynamic Braking Resistors. The braking resistor represents a large resistive load which is switched to arrest system acceleration (19). The dynamic brake is an emergency control, whose action is limited in time mainly by the device's thermal capabilities. When generators in the sending area start accelerating with respect to generators in the receiving area, switching a large resistive load in the sending area reduces the power flow on the interconnection and helps the synchronizing power. The Bonneville Power Administration installed a 1400 MW braking resistor at the Chief Joseph substation.

Load Tripping. Direct load tripping can be used to enhance system transient stability. A tripping load in the receiving area reduces the intertie transfer, therefore improving transient stability. Load tripping disconnects large industrial loads which can tolerate power interruptions. Load tripping schemes in service today are based on detecting a critical line outage and are armed for high intertie flows.

August 10, 1996 WSCC System Outage

On August 10th 1996, a major disturbance occurred in the Western Systems Coordinating Council system resulting in breaking up the system into four islands and the loss of 30,137 MW of load affecting 7.49 million customers in the western North America (20). The disturbance originating in the Pacific Northwest was caused by transmission line outages and generator tripping and propagated through the entire western North American interconnection. Most of the load was lost in Southern California and Arizona areas. The system instability was manifested in growing oscillations on the California–Oregon ac intertie (*COI*) and Pacific HVDC Intertie (*PDCI*).

Predisturbance Conditions. The system conditions in the Pacific Northwest (*PNW*) before the event were characterized by high north-to-south flows on the California–Oregon Intertie (COI) and the Pacific HVDC

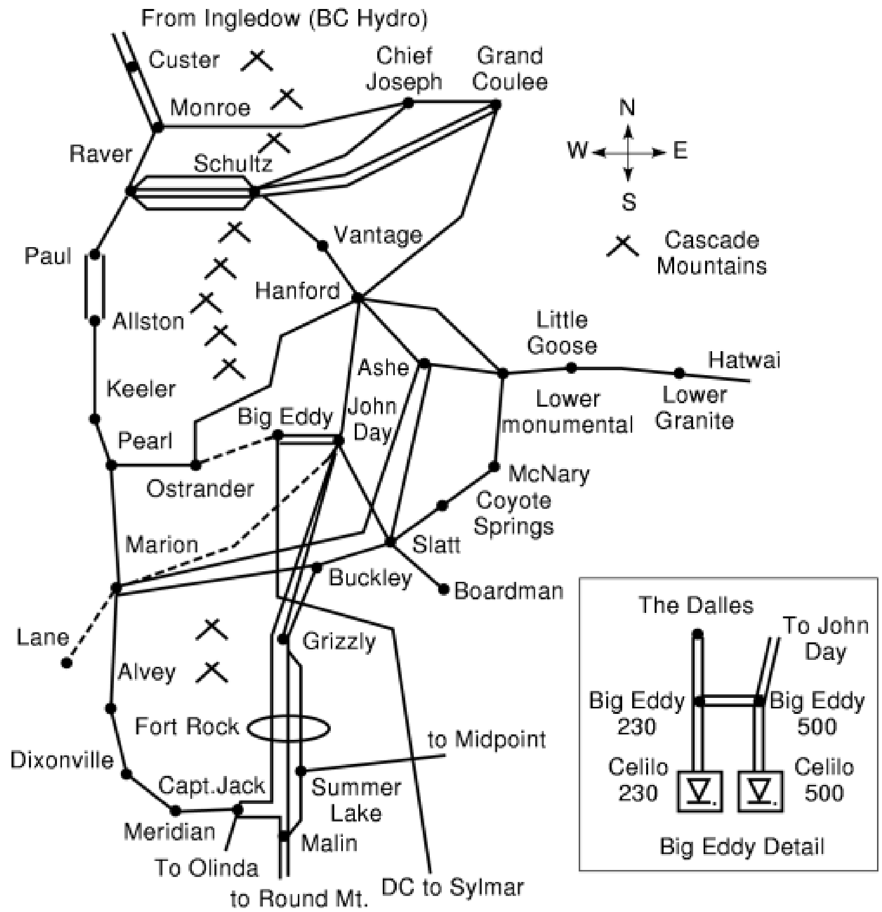

Fig. 1. One-line diagram of major 500 kV lines in the Pacific Northwest.

Intertie (PDCI). Figure 1 shows a one-line diagram of major 500 kV lines in the PNW and details of the Big Eddy area. Table 1 shows the path of major power flows and the percentage loading of each path rating.

The PNW generation pattern was characterized by high exports from Canada, high generation in the Upper Columbia (Grand Coulee, Chief Joseph) and low generation in the Lower Columbia area (John Day, The Dalles). Before the disturbance, there were two forced outages of 500 kV lines in the system: John Day–Marion–Lane and Big Eddy–Ostrander. A scheduled maintenance outage of the Keeler 500/230 kV transformer reduced reactive power support and voltage control at the 500 kV bus from the static var compensator at the Keeler 230 kV bus.

The Initial Stage of the Disturbance. At 15:42:37, the Allston–Keeler 500 kV line sagged close to a tree and flashed over. The line was tripped following unsuccessful single-pole reclosure. Because of the Keeler breaker configuration, the Keeler–Pearl 500 kV line also opened. Before the outage, the Allston–Keeler line was carrying 1300 MW. This power shifted to 500 kV lines east of the Cascade Mountains (through the Hanford bus) and to the underlying 115 kV and 230 kV network. The lower voltage lines parallel to the Allston–Keeler 500 kV line became loaded up to 115% of their thermal ratings. Voltages in the lower Columbia area were depressed to 508 kV at Hanford, 504 kV at Big Eddy, 510 kV at John Day, and 505 kV at McNary. About five minutes later, the Merwin–St. Johns 115 kV line tripped because of a relay failure, and the overloaded

Table 1. Power Flows on Major PNW Paths Before the Disturbance

Path	Flows MW	Direction	Rating MW	Loading %
California–Oregon Intertie	4,350	N-S	4,800	91
Pacific HVDC Intertie	2,850	N-S	3,100	92
B. C. Hydro-Northwest	2,300	N-S	2,300	100
Midpoint-Summer Lake	600	E-W	1,500	40

Ross–Lexington 230 kV sagged into a tree. These lines are parallel to the Allston–Keeler 500 kV line. About the same time, at 15:47:37, sequential tripping of thirteen McNary units began because of exciter protection malfunctions at high field voltage. This started system power and voltage oscillations (Fig. 2). Figure 2 shows the following:

(1) power output from the McNary power house;
(2) Malin 500 kV bus voltage;
(3) COI power (sum of flows in the Captain Jack–Olinda and both Malin–Round Mountain 500 kV lines); and
(4) British Columbia–PNW tie power (both Ingledow–Cluster 500 kV lines).

For up to 40 s on the plot scale, the power oscillations were sustained at near zero damping.

The Final Stage, Instability and Separation. Following the initial tripping of the McNary generators, the system frequency dropped, the COI export decreased, and significant BPA area control error developed. Figure 3 shows the following:

(1) McNary generation;
(2) BPA area control error; and
(3) Grand Coulee unit 20 frequency.

Subsequent automatic generation control (*AGC*) and governor actions tried to restore the system frequency and the COI interchange flow. The AGC power pick up occurred primarily at the Grand Coulee, John Day, and Chief Joseph power plants. Figure 4 shows the power output increase at

(1) Grand Coulee;
(2) Chief Joseph; and
(3) John Day.

An increase in Canadian exports caused by governor action was also recorded.

The power pick up occurred primarily in the Upper Columbia area, further stressing the east-of-Cascades 500 kV transmission lines and depressing voltages in the Northwest area. Because of increased line loading and limited reactive power support from Lower Columbia generators, the system voltages continued to decay on average. Figure 5 shows the Big Eddy and John Day 500 kV voltages from BPA SCADA (two-second data sampling).

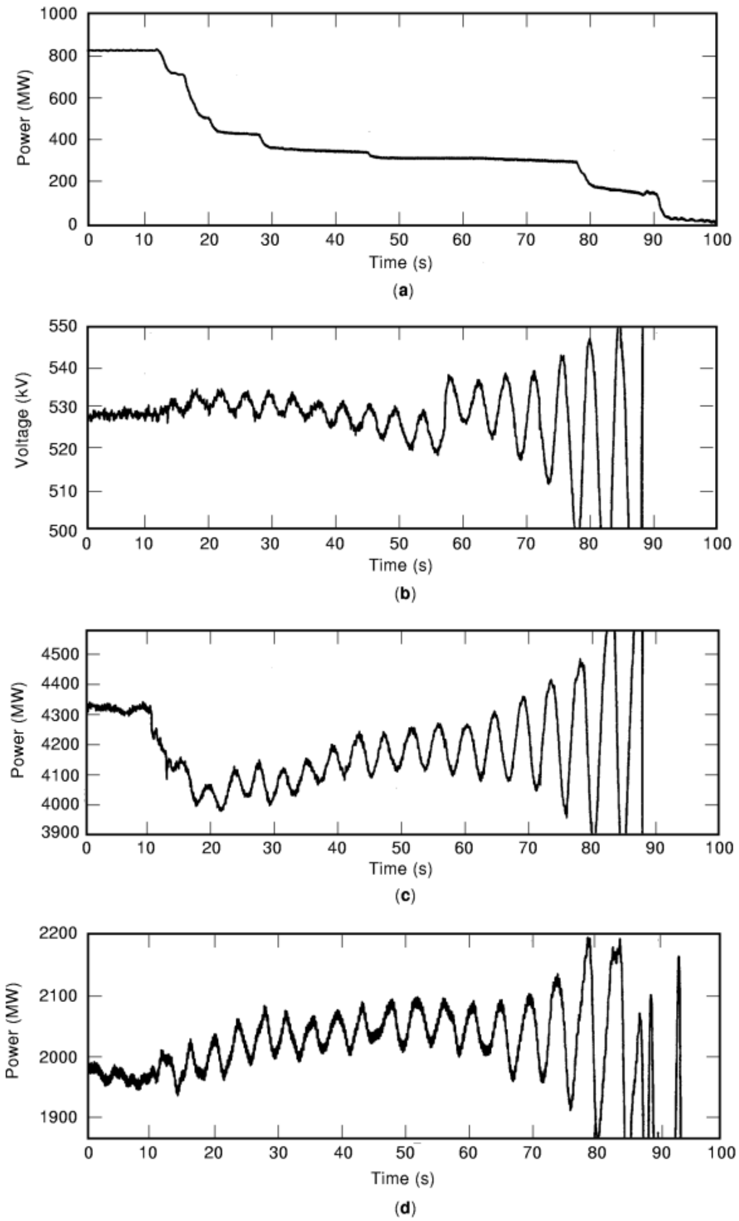

Fig. 2. Recordings of the August 10, 1996 WSCC system outage (starting at 15:47:30).

The Pacific HVDC Intertie has a four-terminal bipolar configuration. Each end consists of *existing* converters and parallel *expansion* converters (26). PDCI operates in the constant power mode at the pole level and was maintaining initially constant power control (Fig. 6). As Celilo ac voltages continued to decay on average, the existing converters started limiting out and losing current control during the lower portion of the ac voltage swings. During the upper portion of the ac voltage swings, the converters regained current control.

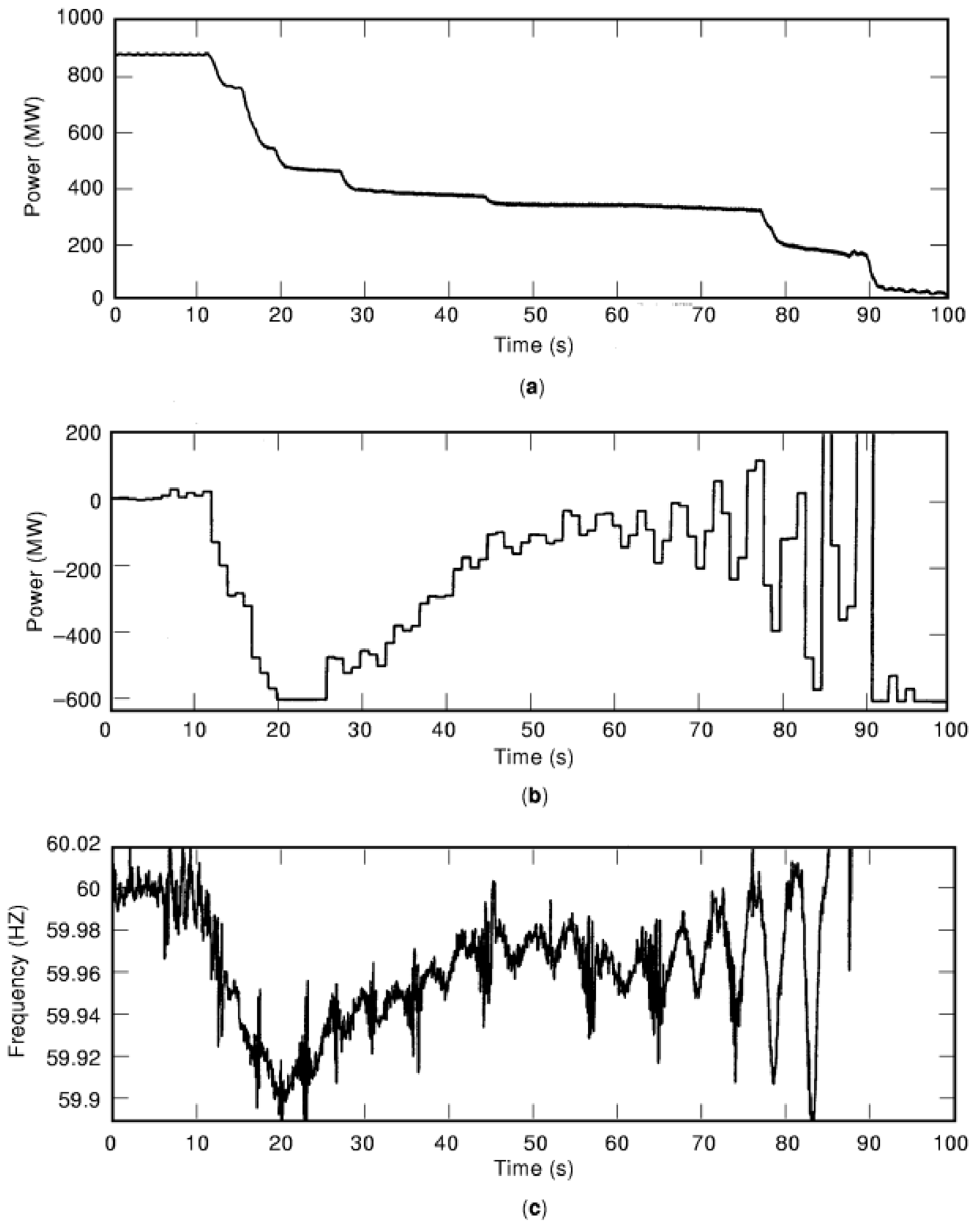

Fig. 3. Disturbance recordings of the McNary tripping, BPA area control error and the Coulee generator frequency (starting at 15:47:30).

Ac voltage oscillations and converter control limits caused the PDCI power oscillations. There is a function within PDCI controls which attempts to maintain dc power constant by transferring the current control from a rectifier (Celilo) to an inverter (Sylmar) when the rectifier becomes limited. This function contributed to dc power oscillations, resulting in dc power swings below and above the power order set point.

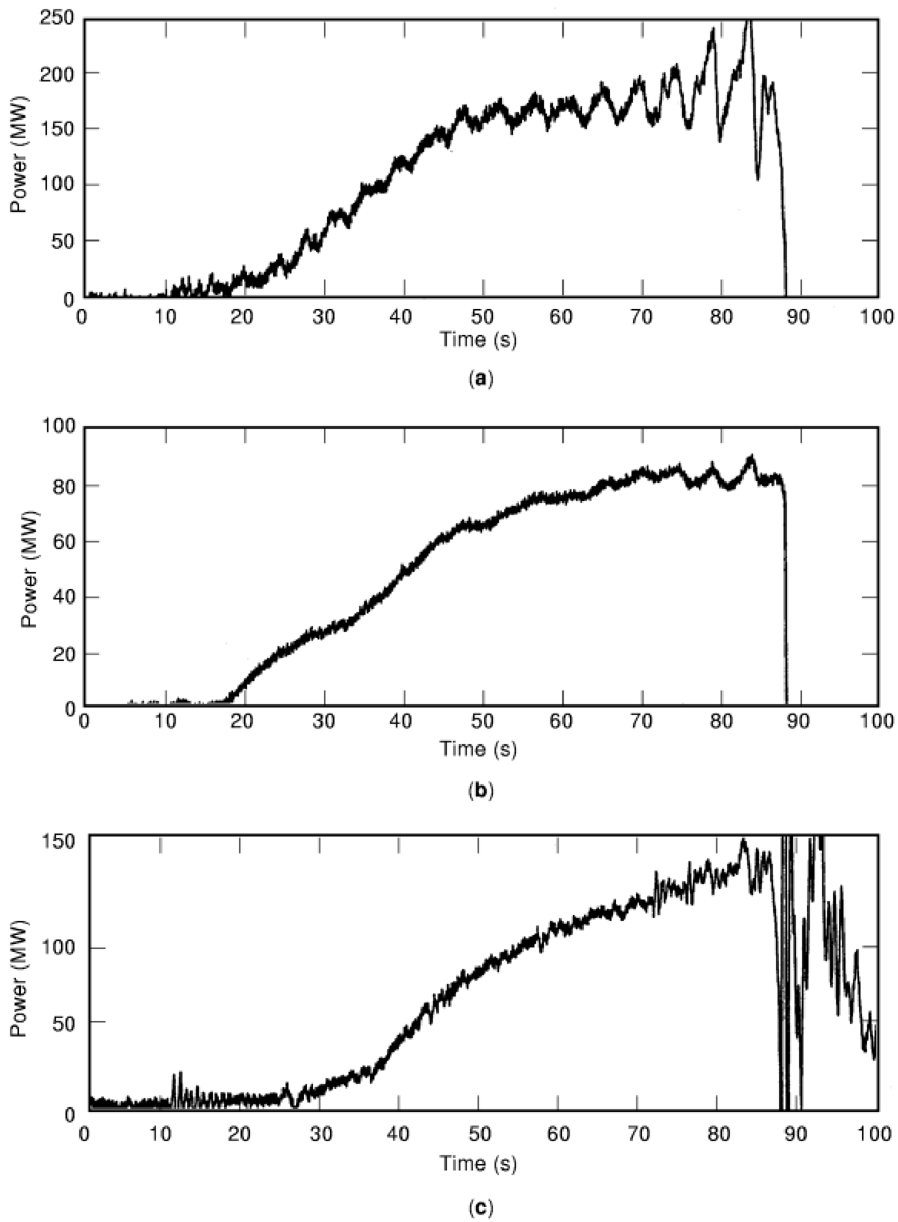

Fig. 4. Disturbance recordings of the responses of major power generation plants in the Pacific Northwest to AGC action and frequency drop following McNary tripping (starting at 15:47:30).

Figure 6 shows the following:

(1) COI power;
(2) total PDCI power at the Celilo converter station;
(3) Celilo existing converter power (connected to the 230 kV ac network); and
(4) Celilo expansion converter power (connected to the 500 kV ac network).

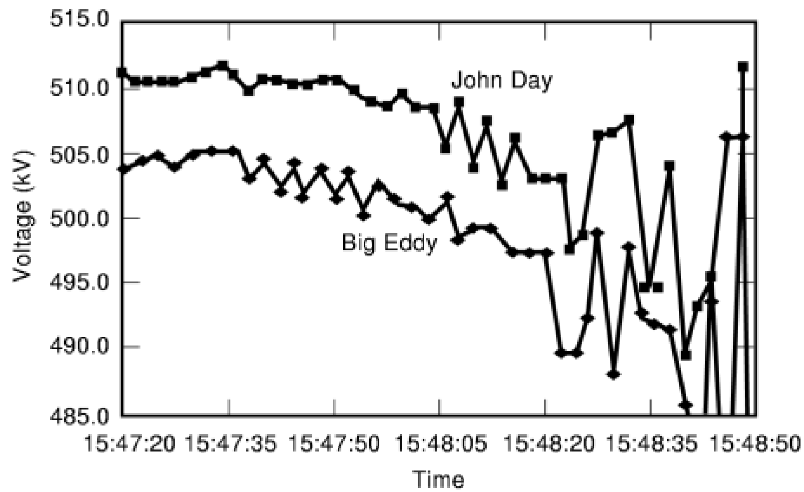

Fig. 5. BPA SCADA voltages in the Lower Columbia area.

As the PDCI started participating in the oscillations, the ac system oscillations started picking up in magnitude, and the COI separation occurred at 15:48:52 (lines were relayed because of low-voltage, high-current conditions).

Discussion of Instability. Although the instability was manifested in growing oscillations on the California–Oregon Intertie and Pacific HVDC Intertie, it was the result of highly stressed system conditions and deficient reactive power support in the system.

Loss of transmission lines (particularly Allston–Keeler and Ross–Lexington) weakened the transmission system, increasing the phase angles between bus voltages along the ac intertie. Before the Allston–Keeler and Ross–Lexington line outages, the angle between Coulee and Malin voltages was about 58° (positively damped power oscillations). Following the outages, the angle increased to 67° (marginal damping). Shifting generation to Upper Columbia by AGC further increased the angle to 72° (at the same time system oscillations became negatively damped). Stressed conditions caused a generator response resulting in negative damping. Low-voltage conditions also caused an undesirable dynamic response by the Pacific HVDC Intertie. The PDCI power oscillations were contributing to negative damping in the system.

System Reinforcements After the Outage. Following the outage, a comprehensive set of actions was taken to improve system stability:

(1) Transmission system reinforcements. Shunt capacitor banks were installed at Hanford and John Day 500 kV substations providing additional reactive power support in the Lower Columbia area. Shunt capacitors at John Day also allow better use of dynamic reactive capabilities of John Day generators during system transients. A 230 kV shunt capacitor bank was installed at Big Eddy substation to provide voltage support to the Celilo terminal of the Pacific HVDC Intertie.

(2) On-line dynamic monitors. Phase-angle, reactive power, and oscillation monitors were developed by the Bonneville Power Administration. The phase angle monitor uses on-line information to alarm dispatchers when the relative phase angles between voltages at key substations (Grand Coulee–John Day–Malin) exceed normal or emergency settings. A reactive reserve monitor alarms dispatchers when the reactive power reserves at Lower Columbia hydro plants (The Dalles, John Day, and McNary) are becoming too low. An oscillation monitor detects critically damped power oscillations on the Intertie to alarm a system operator.

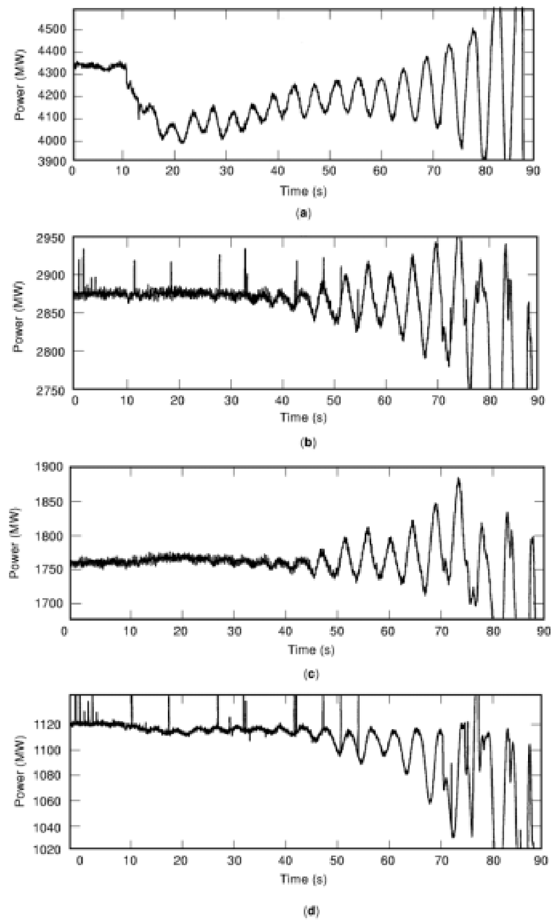

Fig. 6. Disturbance recording of the PDCI response (starting at 15:42:30).

(3) Stability controls. A comprehensive control scheme was designed to correct dynamic performance of the Pacific HVDC Intertie under low ac voltage conditions. In parallel, a very effective control scheme, called fast ac reactive insertion, was installed at the ac intertie. Based on local measurements, the scheme inserts series capacitors in all three lines at the Fort Rock 500 kV substation and shunt capacitors at the Malin 500 kV substation.

(4) Improvement of generator controls and protection. Faulty relays at McNary power plant were replaced with new relays. A program of retuning power system stabilizers at the Lower Columbia generators is currently in progress. Capability to operate the Dalles generators as synchronous condensers was implemented, allowing voltage support for postoutage conditions.

After the disturbance, the combined operating transfer capability of the California–Oregon Intertie and Pacific HVDC Intertie was reduced considerably. The system reinforcements allowed restoring the original rating partially.

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