Report 3.1

Part I – State-of-the-Art in Special Protection Schemes and other Measures to Prevent Widespread Blackouts: BPA and WSCC Experience

Part II – Assessment of Brazilian Power System Reliability and Suggested Areas for Improvements

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3.1.1 Introduction

Power companies in the western North American interconnection belong to the Western Systems Coordinating Council (WSCC). The WSCC is one of the regional reliability councils of the North American Electric Reliability Council (NERC). The amount of generation and load is 100,000–150,000 MW. The general structure of the Western North-American Interconnection is shown in Figure 1.

Bonneville Power Administration (BPA) is one of the largest transmission owners in the western interconnection, operating over 7000 km of 500-kV transmission lines in the states of Washington, Oregon, and Montana. BPA also operates the northern portion of the 3100 MW, ±500-kV, 1350 km Pacific HVDC Intertie. BPA has a northern intertie with BC Hydro (two 500-kV lines and two 230-kV lines, up to 2800 MW capacity), a Pacific or California-Oregon AC Intertie (three 500-kV lines, 4800MW capacity), and eastern interconnections in Montana and Idaho.

Because of long distances, remote hydro and coal-fired generation, and large unpopulated areas, parts of the western interconnection are not highly meshed. This system structure reduces reliability, and many cascading power failures have occurred. A particular feature of the western interconnection is the Pacific Intertie comprising parallel 500-kV ac and ± 500-kV dc interties. With good hydroelectric conditions, large amounts of Pacific Northwest hydro power are transferred to California (current capability is 7900 MW). The Pacific Northwest includes the states of Washington and Oregon, and the Canadian province of British Columbia.

Outages on either the Pacific ac or dc intertie during high loading conditions have a major affect on the remainder of the interconnection, especially on lower capacity parallel paths from the Pacific Northwest to California in the eastern part of the interconnection (states of Utah, Colorado, New Mexico, Arizona, and Nevada). Many stability controls are used to avoid cascading power failures. Most importantly, up to 2800 MW of hydro generation is tripped for Pacific Intertie outages. Controlled islanding is a second important control for Pacific Intertie operation. Without these stability controls very expensive system reinforcements would be required.

These stability controls are termed “remedial action schemes” within the WSCC. Other terms are “special protection schemes/systems” and “emergency controls.” We will use the term special protection schemes or (SPS).

Many of the earlier cascading power failures involved failure of special protection schemes. A large and expensive effort was made in the 1980s to improve SPS reliability. The cost range for the SPS reliability improvements was $10-20 million. The schemes are described in detail below. Expansion of the high reliability schemes described below is very expensive: some hundred thousands of dollars for adding line loss logic and communications for outage detection of another line.

Between 1994 and August 1996, a series of four cascading power failures occurred in the western interconnection. Table 1 summarizes these failures. Appendix 1 and the references describe the failures in detail. Two other interesting power failures are also described in Appendix 1. Lessons learned from these outages are discussed below.

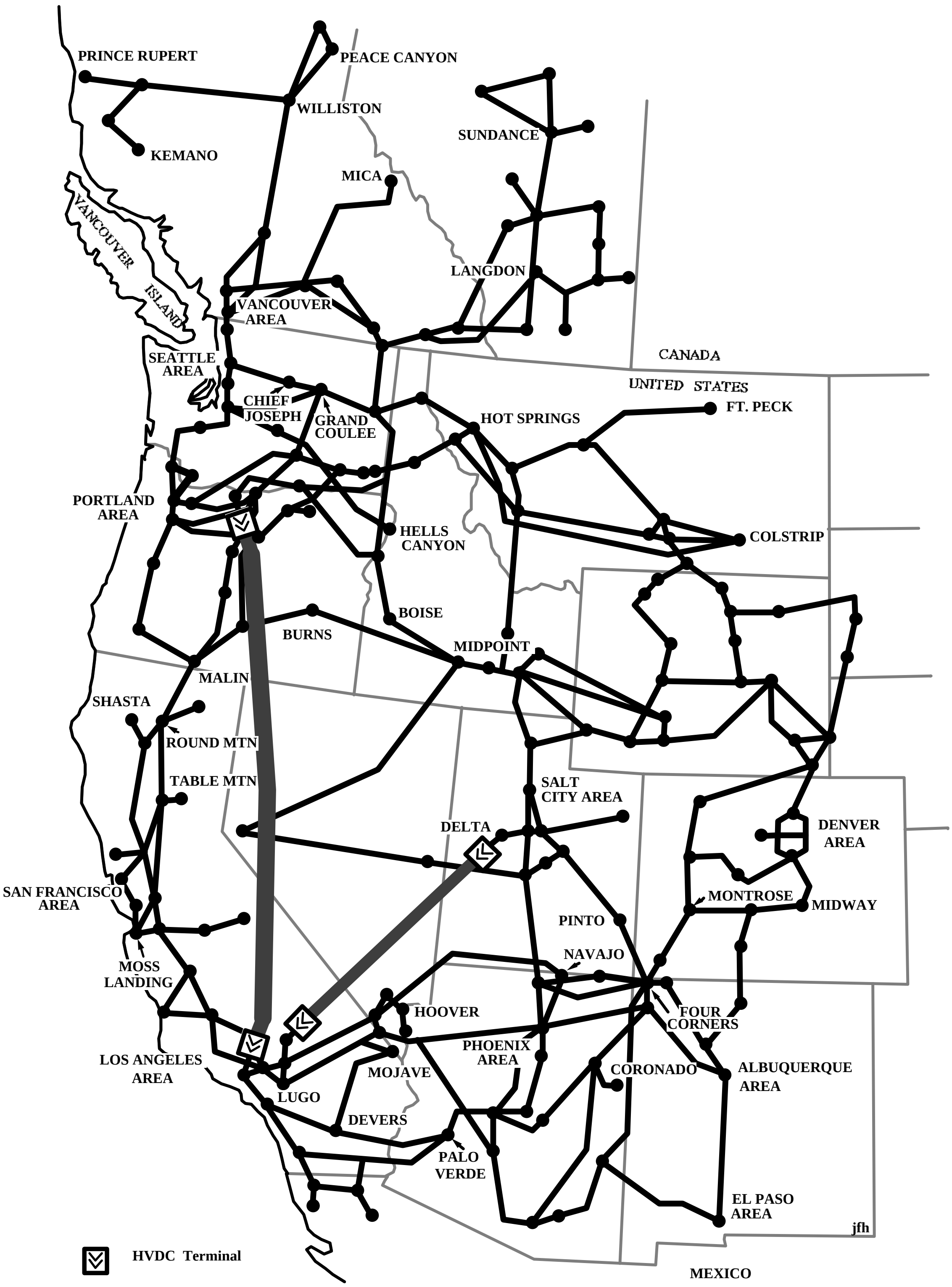

Fig. 1. General structure of the Western North-American Interconnection

Date and time	Pacific Intertie Flow	Number of Islands	Load Loss [a]	Generation loss
January 17, 1994 0431 hours	S to N	5	7,500 MW	6,400 MW
December 14, 1994 0125 hours	S to N	5	9,336 MW	11,300 MW
July 2, 1996 1424 hours	N to S	5	11,743 MW	9,909 MW [b]
August 10, 1996 1548 hours	N to S	4	30,489 MW	25,578 MW [c]

a. Much of load loss by controlled underfrequency load shedding.
b. Includes intentional tripping of NW hydro generation for Pacific intertie outage.
c. 175 units excluding intentional tripping of NW hydro generation for Pacific intertie outage (some units lost due to loss of transmission lines)

Table 1. Recent cascading outages in the western North American interconnection.

3.1.2 BPA Wide-Area Special Protection Schemes

The most important and elaborate special protection schemes are associated with the Pacific ac and dc interties. We will discuss the ac intertie schemes, which mainly uses direct detection of line outages. SPS is applied to meet the WSCC Reliability [1] and the WSCC Minimum Operating Reliability Criteria as determined by planning and operating studies and post-disturbance analysis.

Microwave transfer trip signals from line outages are sent to BPA control centers where scheme arming and decision logic is performed. Microwave transfer trip signals are then sent for generator tripping, 500-kV shunt or series capacitor bank insertion, controlled islanding, and other actions. Simpler special protection schemes for a local area may not be routed through control centers.

3.1.2.1 SPS performance

The WSCC mandates very high reliability for special protection schemes. Each SPS design must be approved by WSCC committees. Each SPS is designed to meet the following performance requirements:

Dependability: Each SPS is designed so that failure of any single detection, communication, logic selection or output element will not result in failure to achieve the intended power system performance.

Security: Each SPS is designed so that an inadvertent output from any single detection element will not result in islanding or loss of firm load.

Independence: Each SPS operates independently of other schemes. Within each SPS, elements are separated into a minimum of two independent sets configured so that an outage, failure or inadvertent operation within one set has no effect on the performance of the other set(s).

Monitoring: Each SPS is fully monitored. The monitoring provides, at minimum, alarms which alert the control center operator to any control system failure or operation of any control element; remote indications that fully inform the operator of the current control system configuration and arming status, and sequence-of-event records which enable full post-disturbance analysis.

3.1.2.2 Control computer, arming, and logic reliability

The Pacific AC Intertie SPS has two identical, yet independent control schemes. One control computer is located at BPA's Dittmer Control Center in Vancouver, Washington and the second control computer is located at BPA's Munro Control Center located in Spokane, Washington.

The control computers are fault tolerant employing two out of three voting for discrete inputs, and middle value selection for analog inputs.

Controller logic (through-put) time is about 50 ms. Complete time from line outage to tripping generation at a distant location is 100-120 milliseconds.

Arming is performed by control center operators based on displays of current conditions, display of nomograms, and alarms. "Standing Orders" or operator instructions describe arming conditions. Standing Orders may be viewed at www.transmission.bpa.gov. Automatic arming has been proposed, but not yet accepted by operators.

In addition to hardware/software reliability, algorithm (control strategy) reliability must be considered. With growing numbers of SPS, and with increased operating complexity, and with changing conditions, there is potential for undesirable SPS operation. There is also potential for insufficient SPS for some operating conditions or disturbances. Industry restructuring causes an order of magnitude increase in trading patterns. The SPS algorithms are only as good as the simulations used to define the SPS logic.

3.1.2.3 Communication

Transfer trip signals are sent over BPA-owned microwave radio. Dual tone transfer trip is used. The microwave radio employs frequency diversity. Geographically-diverse microwave paths are used whenever possible for the independent schemes. Fiber optic communication may be used in future schemes.

3.1.2.4 Line loss logic

Transmission line outages are sensed by independent means. Inputs originate from Line Loss Logic (LLL) subsystems located at each end of each line segment. Each LLL communicates line status over independent microwave radio transfer trip paths to the two control centers.

The LLL uses protective relay trips, transfer trip from remote end, breaker "b" switches, breaker disconnect "b" switches, manual trip, catastrophic loss of gas for gas-insulated breakers, and breaker failure scheme trip to determine line status. A line is determined to be out when a permanent three pole trip occurs.

3.1.2.5 Controlled islanding for Pacific AC Intertie outage

Following opening of a series segment of the Pacific AC Intertie, the above detection and communication schemes are used for western interconnection controlled islanding. Three transfer trip signals are sent from the Pacific Northwest and northern California over independent paths to Four Corners substation in New Mexico. Four Corners is located near where the states of Utah, Colorado, New Mexico, and Arizona join (approximately 1500 km from Pacific Northwest). If two out of three voting indicates Pacific AC Intertie separation, approximately seven lines are opened in New Mexico, Arizona, and Nevada to create northern and southern islands.

The two islands remain connected by the Pacific HVDC Intertie and the Intermountain Power Project HVDC link. HVDC operation for the voltage and frequency excursions in the two islands has been reliable.

For north to south Pacific Intertie flow, moderate underfrequency load shedding may occur in the southern island, but island transient stability is maintained. Intentional hydro generator tripping occurs in the northern island.

3.1.3 Underfrequency Load Shedding

All WSCC utilities use underfrequency load shedding. The load shedding steps have been standardized and start at 59.1 Hz [2].

Coordination is required with thermal power plants that may trip with very short time delays around 57–58 Hz [nerc ps, page 58]. There have been problems with new gas turbine generation that may trip at a frequency of 59.5 Hz. Power plant equipment suppliers tend to recommend unnecessarily sensitive over/under frequency protection without consideration of power system performance.

3.1.4 Undervoltage Load Shedding

Many WSCC utilities have installed undervoltage load shedding [3,4]. Installed undervoltage load shedding in the Phoenix, Arizona area may have prevented a blackout from occurring on a very hot (45°) Saturday afternoon several years ago.

Where loads are dominated by air conditioning and other motor load, the load shedding time delay should be short—around one second. Undervoltage load shedding should only occur for three phase voltage depression.

Experience has shown that undervoltage load shedding compliments underfrequency load shedding. If generation–load imbalance is too high following islanding, voltage may collapse. The loss of load by disconnection or voltage sensitivity slows frequency decay. Also, underfrequency relays may not operate for severely depressed voltage.

3.1.5 Reliability Criteria and System Performance Study Procedures

NERC and WSCC reliability criteria are described in the references [1,3,5]. A key feature is performance tables specifying system performance for various categories of disturbances. The WSCC performance table has performance levels A–E; see Appendix 4. Performance is specified by allowable transient voltage and frequency dips, post-disturbance voltage deviation, thermal loading and oscillation damping. Level A is n-1 criteria, while levels B–E are criteria for multiple outages. Levels A–D are deterministic criteria while level E allows evaluation for risks and consequences.

Since the summer 1996 outages that were partly associated with voltage collapse and insufficient voltage support along power transfer paths, the WSCC has developed rigorous criteria and study procedures for voltage support [3]. As described in the reference, post-disturbance voltage performance is tested by *P–V* curves and *V–Q* curves. *P–V* curve requirements provides a somewhat global criteria for power transfer to a load center or across an interface. *V–Q* curve requirements is a local test of reactive power suport capability. For the most severe n-1 contingency, a 5% power margin is required. From *V–Q* curves, each EHV bus must have positive reactive power margin for 105% load level or interface flow.

Power flow programs are used for the majority of the simulations. Transient stability simulation is also required, and transient stability may be the limiting factor. Transient stability simulations may be run for 30 seconds or longer to include the effect of overexcitation limiters and other longer-term phenomena.

Seasonal studies determine simultaneous transfer path ratings and operating nomograms. Current studies, operating procedures, and nomograms may be found at the BPA transmission business line web site (www.transmission.bpa.gov). Studies affecting transmission capacity are posted on OASIS web sites (Open Access Same Time Information System). An example of a BPA nomogram is given in Appendix 6.

The studies are done in an open environment with peer review by power organizations having both reliability and commercial interests.

If unstudied conditions occur during actual operation, power transfers must be reduced until simulations have determined safe operation. Mandatory compliance procedures are being developed. There will be monetary penalties for operation outside published transfer limits, or for not reducing transfers if unstudied conditions occur.

3.1.6 Future on-line studies

The seasonal studies described above are very manpower intensive. Furthermore, the actual conditions several months in the future must be estimated.

Automated, near real-time on-line security assessment is desirable. After many years of development, BPA's state estimation/on-line power flow software is working well for the Pacific Northwest portion of the WSCC network. Full data exchange is made with BC Hydro and Pacific Gas & Electric, but models for the remainder of the interconnection are crude. WSCC-wide state estimation, required for interarea dynamic security assessment, may be realized in the next years.

Power flow based on-line security assessment is feasible at BPA and is being developed. BPA is currently testing the Powertech Laboratories Voltage Security Assessment Tool (VSAT, see www.powertech.bc.ca). On-line voltage security assessment is feasible for both load area voltage stability and intertie voltage support requirements.

There is a WSCC mandate for on-line security assessment by January 1, 2001. Dynamic security assessment capability for interarea problems will likely be limited, requiring WSCC-wide state estimation for accurate simulation.

3.1.7 Wide-Area Measurement and Response-Based Control

BPA has had control center based dynamic system monitors since the 1970s. The measurements are mainly from power interchange measurements used for automatic generation control. Analog transducers and analog microwave radio are used, and the bandwidth of 1-2 Hz is adequate for analysis of low frequency electromechanical oscillations. About 100 channels are monitored. The original monitor is on a control center VAX computer. A new personal computer based Portable Power System

Monitor (PPSM) using LabVIEW software has also been developed. The PPSM can also be installed in substations, and the PPSM can be remotely controlled.

The monitors have proved invaluable for rapid analysis of disturbances from BPA's main control center, or even from an engineer's home. The monitors also allow conducting field tests from the control center. Sophisticated signal processing is possible using either LabVIEW or Matlab software. Data can be saved using triggers, but large hard disks can store several weeks of data.

A new generation of monitoring equipment is now implemented at BPA. This equipment is digital positive sequence synchronized phasor measurements. Synchronization of phasors from various switchyards is via GPS. The data is telemetered to BPA's main control center using modems over BPA's microwave network. For new installations, fiber optic communication is preferred. Tests have shown latency (time delay) of around 70 ms for modems and microwave radio and around 20 ms using fiber optics.

Phasor Measurement Units (PMUs) are installed at eight Pacific Northwest locations, and at the Sylmar converter station near Los Angeles. Over 100 voltage magnitude, voltage angle, active power, reactive power, and bus frequencies are available, or are computed from the measurements. Additional BPA installations are likely as well as telemetered phasors from other utilities (e.g., Southern California Edison and Pacific Gas & Electric). The digital positive sequence measurements are more accurate and less noisy than the analog measurements. The control center has a display (with alarm thresholds) of voltage angles for operator information.

The phasor measurements will probably also be used as high quality measurements for state estimation.

Wide-area voltage control and stability control is being developed using the synchronized phasor measurements as inputs. A control center based fault-tolerant computer will be the platform for centralized control. Control actions will include generator tripping and capacitor bank switching. Most of the outgoing transfer trip signals are existing as part of BPA's special protection schemes.

The response-based control will detect severe disturbances not covered by line loss logic special protection schemes. Response-based refers to control based on measured variable changes (swings) rather than the direct detection of outages. The first application is fuzzy logic voltage control based on voltage magnitudes and power plant reactive power outputs. This should be considered R&D.

3.1.8 Summary of Lessons Learned from Recent Cascading Failures

Following the power failures, WSCC committees prepared reports with 144 recommended actions. Most of these actions are completed, but some remain technically challenging. On-line, near real-time security assessment of large portions of the interconnection is one challenge.

We will summarize the most important and interesting lessons learned, and actions taken. Some actions such as improved tree trimming on right-of-ways are omitted.

3.1.8.1 Generation control and protection design tolerant to abnormal voltages, currents, and frequency

Undesirable generator tripping was the main factor in the severity of the disturbances. Islanding (separation of portions of an interconnection) almost always results in tripping of units because of the voltage and frequency excursions. Control and protection may be miscoordinated. Various generator protection may operate undesirably including stator overload protection, transmission fault backup protection, volts/hertz protection, and loss of excitation protection. During the August 10th event, protection of thyristor-rectifier excitation equipment misoperated because of high harmonic voltages associated with high field voltage; this caused tripping of all thirteen units at the McNary hydroelectric plant. Many overexcitation and underexcitation limiters are poorly designed, and settings may not be well coordinated with other control and protection. Boiler protection often trip generators minutes after a disturbance.

In some cases, control and protection with known defects were not expeditiously replaced because of budget and staff constraints. Some units that tripped on August 10 also tripped during previous disturbances.

Best practice engineering and state-of-art digital control and protection are solutions. Best practice engineering needs to be better documented, perhaps as a comprehensive IEEE guide. As discussed below, one WSCC-mandated action requires power plant testing that, in many cases, resulted in retuning or equipment replacements.

Transmission network control and protection also may operate undesirably during abnormal conditions. Undesirable operation of protective relays has contributed to many blackouts—relays installed to detect short circuits sometime operate during overload and/or depressed voltages.

3.1.8.2 Improved special protection schemes for infrequent abnormal conditions

Since it’s exceedingly expensive to design a power system to withstand infrequent multiple outage events, it’s common to provide controls to mitigate the effect of disturbances. Following the 1965 Northeastern North America blackout, for example, underfrequency load shedding became standard utility practice

Load shedding or fast capacitor bank switching in southern Idaho would have contained the July 2 initial outages. Undervoltage load shedding operating during the initial 1–1.5 seconds of fast voltage decay is one possibility. More sensitive load shedding is based on a combination of high reactive power output at generators and depressed voltages. Capacitor bank energization and load shedding controls have been installed.

Controlled separation that cleanly separates the system into islands is an effective mitigation measure. For instability and opening of the Pacific AC Intertie, signals are sent to open lines between Colorado/Utah/Nevada and New Mexico/Arizona/California. This controlled separation of the WSCC network into north and south islands had been in service for many years, but was not normally in service after a third 500-kV transmission path was added between the Oregon border and the San Francisco area. The controlled separation is now back in service with three separation signals sent from the Pacific Northwest to Four Corners, New Mexico. Two out of three voting is used for high reliability.

Other special protection schemes have been added. Following outages of 500-kV lines, shunt capacitor banks may be energized, or sending-end hydro generators may be tripped.

3.1.8.3 Voltage support for stability

Voltage support along transmission paths improves synchronous stability. On August 10, reduced voltage support in the lower Columbia River area following the Keeler–Allston outage contributed to the instability that occurred minutes later. The reduced voltage support was due to inappropriate generator excitation controls, power plant operator actions, Pacific HVDC Intertie control response, and the McNary power plant tripping [6–9].

Two new combined-cycle power plants (Coyote Springs and Hermiston) had supplementary power factor control loops that overrode automatic voltage control. The reactive power output of the Boardman generator was reduced by operator action. These actions put more voltage support burden on the McNary plant.

The 3100-MW Pacific HVDC Intertie north-end converter station was operating as a rectifier in constant power control. The depressed ac voltage in the lower Columbia River area caused increase in direct current and increased reactive power demand from the ac network. The increased reactive power demand reduced available ac network voltage support. Bonneville Power Administration (BPA) has implemented a new control that reduces direct current for depressed ac voltage [9].

The number of generating units on-line at The Dalles and John Day were reduced because of requirements to spill water to aid downstream migration of juvenile salmon. This also reduced lower Columbia River area voltage support. Since the water spill requirement is on-going, units at each plant have been modified to operate as unloaded synchronous motors providing voltage support by excitation control. Compressed air is used to “unwater” the units so that the turbines are spinning in air.

Two 550-kV, 460-MVAr shunt capacitor banks were installed in the lower/mid Columbia River area as additional reactive power support. These banks, likely the world’s largest, increases the continuously-controlled reactive power reserve of nearby generators.

While control centers typically monitor transmission voltage magnitudes, reactive power reserves at power plants are a more sensitive indicator of voltage security. Voltages can be normal, but if generators are near their reactive power limit voltage support for disturbances is limited. In 1997 Bonneville Power Administrated implemented a reactive power monitor to provide operators with greater visibility of reactive power output of generators [10]. If reactive power reserve at selected power plants decline below limits, alarms alert operators to take corrective actions including reducing power schedules.

Other measures have been taken at power plants to improve voltage support capability. For example, automatically controlling the high-side transmission network voltage is more effective than controlling generator terminal voltage.

3.1.8.4 Power oscillation damping

The August 10 instability mechanism was growing electromechanical oscillations as the result of high power transfers from British Columbia to California and of the weakened Lower Columbia area. Negative damping is largely caused by generator automatic voltage control phase lags and high gain. The primary means to add damping is a generator voltage regulator supplementary control termed power system stabilizer (PSS). Power system stabilizers at a large nuclear plant in Southern California were out of service. PSS at this location is effective since it is near one end of the north–south intertie oscillation mode. Other stabilizers were out of service, or ineffective because of noisy frequency transducers or other problems. The nuclear plant stabilizers are now in service, and other PSS improvements are underway.

We are evaluating other means to improve damping. Especially promising is bang-bang switching of the Slatt thyristor-controlled series capacitor.

3.1.8.5 Simulation studies, system modeling, and reliability criteria

The July 2 and August 10 conditions were not adequately studied to verify compliance with WSCC reliability criteria. For example, the effect of the fish-related reduced generation at The Dalles and John Day on Pacific Intertie transfer capability had not been carefully evaluated. Investigation found many data problems in simulation programs, including the reactive power capability of key power plants.

As a result the WSCC has made many improvements in simulation methods. A key requirement is validation of steady-state and dynamic simulation data by power plant testing. Dynamic simulation methods are more detailed, with modeling of slower-acting equipment such as generator overexcitation limiters.

Interarea simultaneous transfer capabilities are determined seasonally in an open environment. Simulation procedures are more rigorous, and reliability criteria for planning and operation have been strengthened, especially for voltage support. Operation outside studied conditions is not allowed.

The seasonal simulation studies and subsequent closer to real-time off-line studies are manpower intensive. Actual operating conditions are always different than the studied conditions. If there is a forced outage of, say, a 1000-MVA 500/230-kV transformer, power transfers may have to be reduced until an engineer can modify a previous data set, and simulate and analyze the new situation.

A goal is real-time, on-line transfer capability and security assessment. The technology is essentially available, but implementation is not a trivial task. On-line security assessment is based on a static state estimation involving thousands of measurements for even one region of an interconnected power system. State estimation is working on a regional basis, but further data exchange and development is required for WSCC-wide state estimation. State estimation and the resulting on-line power flow model is the starting point for evaluating transfer capability constrained by reliability criteria for potential outages.

3.1.9 Assessment of Brazilian Power System Reliability and Suggested Areas for Improvements

This very preliminary assessment and the suggested improvements are based on discussions with the following engineers:

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Measures should be taken to increase the reliability of the Brazilian bulk power because of the following factors:

- Existing problem areas,
- high load growth,
- generation and HVDC infeed additions,
- difficulties in building planned transmission lines,
- uncertainties associated with industry restructuring.

Regarding load growth, recall that reactive power consumption of transmission lines and transformers increase with the current squared. Five percent increase in current because of load growth, increases reactive power consumption by about 10%.

Problem areas are discussed below.

1. The Baurú and Cabreúva 440-kV busses lack bus differential protection and local breaker failure protection. These are main and transfer busses, and a bus fault requires time delay clearing from remote locations. With slow clearing, an initial single-phase bus fault may easily evolve into a multi-phase fault (this did not happen for the March 11 Bauru fault).

Mr. Shiraishi indicated that bus differential relaying is being added at Bauru. Each bus section should have bus differential protection.

Most EHV busses in Brazil employ breaker-and-one-half bus configurations. Bauru, Cabreúva, Jacarepagua, and Pimenta are exceptions. With breaker-and-one-half bus layout, a bus fault does not disconnect transmission elements.

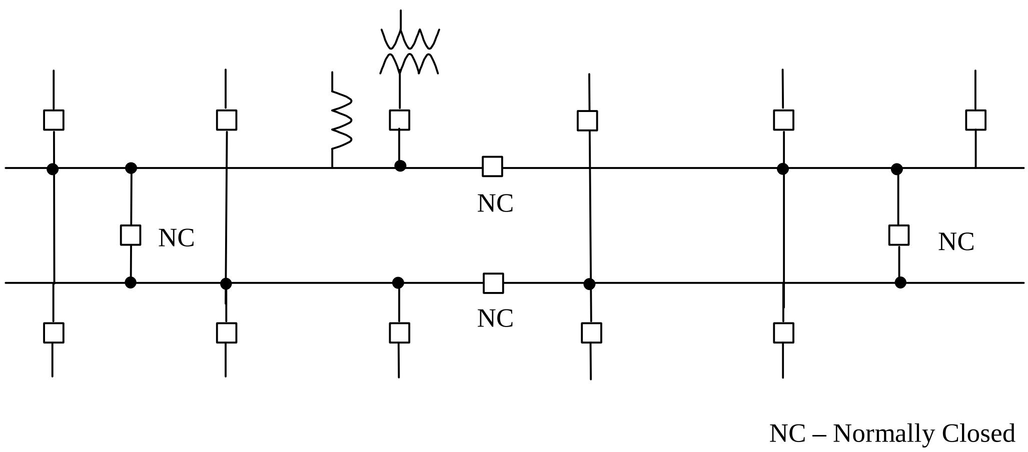

Fig. 2. Arrangement of Baurú with four bus sections. Bus differential protection for all four busses. A fault on a bus section causes the outage of at most three lines

Charles Fromén suggested converting the Baurú two section bus to a four section bus as shown on Figure 2. The advantage is simpler relaying and fewer transmission line outages for a bus fault. The disadvantage is that a line must be removed for circuit breaker maintenance. This possibility should be investigated.

2. The opening of the Três Irmãos –Ilha Solterira transmission line was highly undesirable. Apparently it opened because of a zone 3 relay with very long reach that operated on overload or electromechanical swing. The long reach is used because of long lines in series with the short Três Irmãos –Ilha Solteira line.

Operation of zone 3 and other backup distance and overcurrent relays on overload and/or voltage depression has contributed to many blackouts. Applications of these relays should be investigated throughout the Brazilian high voltage and extra high voltage networks, and at power plants. As described in Appendix 2, BPA stopped using zone 3 relays on important lines in the early 1970s. Investments in improved protective relaying and communications will be required. Critical zone 3 and other backup relays should be modeled in dynamic simulations.

The North American Electric Reliability Council (NERC) Planning Standards state: "Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible" [5, page 49].

3. On-load switching capability of EHV shunt reactors should be reviewed. Switching devices may improve emergency operation and restoration following a blackout.

4. For heavy load conditions, reactive power output of generators, synchronous condensers, and static var compensators should be reviewed for reactive power reserves. Additional switchable shunt capacitor banks to increase reactive power reserves of generators, condensers, and SVCs should be considered. Automatic or operator control could be based mainly on reactive power output of the generators, condensers, and SVCs. It was mentioned that São Paulo area synchronous condensers (S. Angelo, Embuguau, T. Preto, and Ibiuna) often operate with small reactive power reserves. The effect of shunt capacitor banks in the vicinity of the Ibiuna inverter station should not significantly affect the Ibiuna effective short circuit ratio.

5. The excitation equipment of the São Paulo area Henry Borden power plant should be reviewed for possible modernization. The excitation equipment has discontinuous voltage regulators and dc generator exciters. The technology is over 50 years old. Because of its proximity to São Paulo, this is an important plant, and is used for black start.

6. In view of power system changes including ownership changes, restoration plans should be updated. Power system restoration in an emergency should be planned on a one-system basis, without regard to commercial factors. (Capability for blackstart could, however, be an ancillary service.)

As an example, Charles Fromén mentioned that, following a blackout, power to the Eletropaulo control system was previously provided from the Henry Borden plant. Because of ownership changes, power to the Eletropaulo control center was not quickly restored on March 11.

Drills involving many companies, field tests, and simulator training could be considered to improve restoration practices. The types of load connected initially might be reviewed. The best type of load has significant voltage and frequency sensitivity. Energization of large motor loads disconnected following the outage should be avoided because of the high starting currents. An example might be a large residential area with connected air conditioning.

7. Misoperations of protective relays should be promptly investigated and problems resolved. A central reliability authority (previously carried out by GCOI/GTP) should provide oversight of EHV and power plant relay misoperation and the resolution of the problems.

Charles Fromén mentioned two misoperations of Itaipu 750-kV protection that resulted in underfrequency load shedding by Eletropaulo. The Itaipu transmission protective relays from General Electric might be considered for replacement to improve both primary protection. Misoperation of the 1970 vintage GE relays have caused problems in other power systems. Replacement would also improve out-of-step relaying, including compatibility with the ABB relay sets. **Note**: *Johann is checking on the misoperations. Two simultaneous outages occurred in October 98 because of atmospheric discharge, but relay misoperation was not mentioned.*

8. Mr. Shiraishi mentioned that there are no national guides for out-of-step relaying, and that practices vary from company. Such a guide might be developed. In a meshed network such as the south–southeast network, out-of-step relaying with preplanned controlled separation/islanding locations presents difficulties. One option is to simply rely on separation by distance relays.

If out-of-step blocking is employed, a positive means for out-of-step tripping at selected locations is required. Otherwise, highly undesirable asynchronous operation may occur.

Trip “on-the-way-in” is preferred for EHV lines to avoid a zero voltage condition equivalent to a three-phase fault. Circuit breaker out-of-step tripping capabilities should be verified.

Possible out-of-step-tripping should be modeled or monitored in dynamic simulation.

9. Charles Fromén, representing the transmission customer Eletropaulo, suggested visits to EHV and important HV substations, and also to power plants. A team would audit condition of the facilities affecting system reliability using a checklist plan. Substation and power plant personnel would be interviewed to determine problem areas. Many items could be checked such as control and protection schemes, nameplate ratings, power plant or substation electrical diagrams, communication capability with control centers, blackstart capability, operator training/experience, etc. Relatively simple tests could be requested such as switching a capacitor bank at the substation. At power plants, off-line hydro units could be started and off-line voltage regulator step response tests could be made. Tests to verify reactive power capability of sample units could be easily done. Checks would verify that various types of relays, power system stabilizers, oscillographs, and many other types of equipment are in good working order.

In any power system, such peer-review audits would likely find problem areas. In North America, such audits are performed at control centers by NERC teams. Recently retired engineers with various backgrounds might be used for the teams.

10. It was mentioned that standards should require adequate reactive power capability for new generation, including non-utility generation. For example, a 0.9 power factor capability at the high side of the generator step-up transformer could be required. Another concern discussed is under and over frequency protection of gas turbine and combined-cycle power plants. These must be coordinated with underfrequency load shedding.

11. Operator training simulators were discussed. There has been good experience with the EPRI operator training simulator that is licensed by several EMS vendors. It may be possible, however, to simulate in real time a modest-sized system (few thousand busses) with the inclusion of fast dynamics. A real-time operating training simulator using Eurostag as the simulation engine has been developed and provided to a Chinese company. Including the fast dynamics (as in a transient stability program) increases realism, and may be practical with ever-increasing computer speed.

Available operator training simulators should be used for restoration training.

BPA's operator training simulator is located at the control center adjacent to the dispatching area. Displays are similar to the real displays. Operator training can be conveniently and frequently provided. I suspect the BPA simulator would not be used nearly as much if it was located some distance from the control center.

If possible the same software engines should be used for operation training, future on-line dynamic security assessment, and off-line simulation.

12. Transmission-network breaker-switched shunt capacitor banks should be considered for the parts of the Brazilian network with frequent low voltages or with low reactive power reserves at generators, synchronous condensers, and SVCs. The Rio Grande do Sul state was mentioned as frequently having very low voltages. Shunt capacitors can be applied at EHV levels if transmission lines are loaded above surge impedance loading. Reactive power transfer through transformers should not be excessive.

BPA applies 300–460 MVAr banks at 550-kV and up to168 MVAr banks at 241-kV. Current limiting reactors are used to limit inrush and outrush current. Shunt capacitor banks are relatively low cost, have essentially no losses, and can be added within a year. BPA prices for a recent order of a 460 MVAr bank including circuit breaker was about US$3 million (similar banks had previously been procured by BPA, and the supplier and BPA designs were "off-the shelf").

In many utilities, shunt capacitor banks are the first choice to improve voltages and increase power transfers. Capacitor bank applications at HV and EHV are becoming more common.

The simplest control is for operators to insert banks to provide "base load" reactive power, allowing large reactive power dynamic range on generators and condensers. Backup automatic voltage-based control should be provided. BPA has a reactive power monitor to aid operators in reactive power compensation switching [10].

Sensitive automatic control could be based on both voltage magnitude and reactive power output of generators or synchronous condensers. Programmable logic controllers (PLCs) could be used for this.

Series capacitors (more expensive than shunt capacitors) may also be considered for long transmission lines. SVCs may be justified at some locations.

14. There are shortcomings in information technology equipment such as dynamic system monitors, highly reliable communication networks, and common timing systems. Regarding rapid evaluation of Digital Fault Recorders data, Charles Fromén recommended expert system based automated analysis of protective relay [11].

15. There are some problems with open exchange of information related to system reliability. Following the March 11 event, there were longer than desirable delays to obtain relay and bus layout information.

16. Paulo Gomes mentioned that improved damping of several oscillation modes could be obtained by PSS replacements at Itaipu 60 Hz.

17. Paulo Gomes described the limited reactive power capability of the Itaipu 60 Hz units. For disturbances, overexcitation limiter (OEL) operations may result in São Paulo area voltage collapse. An SPS to trip São Paulo area load or insert capacitor banks for OEL pickup, or for sustained field current or reactive power above continuous ratings could be considered.

18. Paulo Gomes suggested that a Itabera–Campinas 750-kV or 500-kV line is a very good reinforcement. This completes a 750-kV/500-kV ring around São Paulo, and also provides support for the Rio area.

19. New special protection schemes may have applications for infrequent outages in critical substations. For example, detection of line outages at Baurú substation could send transfer trip signals for hydro generation tripping at Jupia, Três Irmãos, or Ilha Solteira power plants. PLCs could be used for line loss logic, and for logic based on transmitted power levels. Hydro generator tripping can be “trigger-happy” since the consequences of unnecessary tripping is small.

PLC-based special protection schemes could also be used for controlled islanding where separation logic and locations can be defined.

Such special protection schemes help provide the defense in depth required to mitigate effects of infrequent and unpredictable multiple outages.

PLC-based special protection schemes can be easily represented in dynamic simulation programs having user-defined modeling capability.

20. On-line, near real-time analysis capability should be developed. This is difficult, and few, if any, utilities, power pools, security centers, or ISOs have working capability for large interconnected system. A step-by-step approach is needed. The first and most difficult step is working state estimation/on-line power flow. Thousands or tens of thousands of “debugged” SCADA measurements and status indicators are required. New technologies such as substation automation, synchronized digital positive sequence phasor measurements, fiber optic communication, and cellular and low earth orbit satellite communication may facilitate the measurements.

The second step is power flow based (static) on-line contingency analysis, including voltage security assessment. This can be useful for areas where state estimation is working well. Voltage security, especially, is more or less a local problem.

The final step is a working state estimation for large portions of the network. On-line dynamic security assessment of interarea stability is then possible.

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9. R. Bunch and D. Kosterev, "Design and Implementation of AC Voltage Dependent Current Order Limiter at Pacific HVDC Intertie," to appear in *IEEE Transactions on Power Delivery*.
10. C. W. Taylor and R. Ramanathan, "BPA Reactive Power Monitoring and Control following the August 10, 1996 Power Failure," *VI SEPOPE*, paper IP-003, Salvador, Brazil, 24–29 May 1998.
11. M. Kezunovic and I. Rikalo, "Automated Analysis of Protective Relay Operation," Intelligent System Application to Power Systems (ISAP'99), 4–8 April 1999, Rio de Janeiro, Brazil.
12. Western System Coordinating Council, *WSCC Disturbance Report of July 2, 1996 and July3, 1996 Outages*, September 19, 1996. Available at www.wscc.com.
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Appendix 1: Description of North American Recent Blackouts

The July 2, 1996 power failure

On Tuesday July 2, loads were very high in southern Idaho and Utah because of temperatures around 38°C. Also, power export from the Pacific Northwest to California on the Pacific ac and dc interties were high (4300 MW and 2800 MW, respectively). The Pacific AC Intertie rating at the California–Oregon border is 4800 MW, and the Pacific HVDC Intertie rating is 3100 MW.

A chain of events started at 1424 hours with a flashover to a tree on the Jim Bridger–Goshen 345-kV line. Misoperation of a ground unit of an analog electronic relay tripped the parallel Jim Bridger–Kinport 345-kV line. The two lines are long, series-compensated lines integrating the four unit, 2000 MW Jim Bridger power plant in Wyoming through a transmission network to Pacific Northwest load centers some 1300 km distant.

Special protection schemes tripped two Jim Bridger units (1000 MW) for loss of two of the three Jim Bridger 345-kV outlet lines. The two units tripped correctly, and this should have ensured stability and prevented further outages. Instead, there was small voltage depression in southern Idaho. Approximately 20 seconds after the initial fault, generators at a small hydro plant in southern Idaho started a power runback and tripped about 4 seconds later. The tripping was because of high field current associated with supporting transmission voltage.

In central Oregon (500 km away), voltage slowly decayed along the Pacific ac intertie. The slow voltage decay in Oregon was partly due to low generation at The Dalles power plant on the Columbia River because of migratory fish related spill, and because a combined-cycle power plant operated in power factor control. After-the-fact simulations showed a high destabilizing sensitivity to west to east power flow on the Summer Lake (central Oregon) to Midpoint (southern Idaho) 500-kV line.

About the same time as the hydro plant tripping, a 230-kV intertie line between western Montana and southern Idaho tripped by a zone 3 distance relay operating on overload and at reduced voltage. A parallel 161-kV line subsequently tripped. The interruption of around 300 MW on these two lines caused power swings through eastern Washington and eastern Oregon, further overloading lines between the Hells Canyon generation complex on the Snake River and the Boise, Idaho load area. Loading on the Summer Lake–Midpoint line also increased. This led to rapid voltage collapse and angular instability. Four 230-kV lines from Hells Canyon generation to Boise tripped about 3 seconds later. Separation of the Pacific ac intertie followed about 2 seconds later. Further cascading resulted in formation of five electrical islands. References 12 and 13 describe the disturbance in detail.

The following day the same initial events occurred. Conditions were slightly less stressed, however, and Idaho Power Company operators tripped 600 MW of load when voltage started to collapse. This contained the disturbance, preventing a repeat of the July 2 wide-area failure.

The August 10, 1996 power failure

Saturday afternoon, August 10, was unusually warm in the Pacific Northwest (38°C in Portland, Oregon). Because of record precipitation, hydroelectric conditions were excellent. In the late summer, generation capability is highest in British Columbia, Canada and power transfers from Canada through the states of Washington and Oregon were near rated values. Prior to the main outage, three 500-kV line sections from the lower Columbia River to the Portland/Salem/Eugene load centers in Oregon were out of service because of tree faults. (The record rainfall and hot weather also made the trees grow!) These lines were lightly loaded, but their capacitance provided reactive power support for the high Canada to California power transfers.

The initiating disturbance was an outage (sagging into a tree) of the Keeler–Allston 500-kV line which severed the 500-kV path between Seattle and Portland on the west side of the Cascade Mountains. The line loading was over 1300 MW. Another line was forced out because the ring bus at Keeler was open because of transformer maintenance. The Canada to California power increased on the lines east of the Cascade Mountains, causing a voltage depression in the lower Columbia River area. Improper voltage control at three power plants contributed to the voltage depression. Voltages sagged from around 540 kV to 504–510 kV.

The transmission line outages overloaded parallel lower voltage lines in the Portland area. About 5 minutes later, a 115-kV line tripped due to a relay failure and a 230-kV line sagged into a tree and tripped. About the same time generators at the McNary hydroelectric plant started tripping because of a faulty relay. Over 80 seconds, all thirteen units tripped (about 870 MW).

This further reduced voltage support and further increased system stress. Growing oscillations, followed by synchronous instability resulted. Cascade tripping of transmission lines resulted in formation of four electrical islands, with massive loss of load and generation. References 6,7 describe the failure in more detail.

The cost of the outage has been estimated at over $1 billion. The cost would have been even higher if the outage occurred on a workday. References 9,10 provide further details.

The December 8, 1998 San Francisco blackout

This blackout is interesting because of similarities with the initiating event of the Brazilian March 11, 1999 power failure. The disturbance affected San Francisco and other portions of the San Francisco peninsula. The disturbance occurred a workday morning rush hour and caused loss of 1200 MW of load. At 0815, a construction crew failed to remove temporary grounds on a 115-kV bus section at Pacific Gas & Electric Company's San Mateo substation.

Furthermore, the substation operator failed to restore bus differential protective relaying following the maintenance.

Energization of the bus section caused a three-phase fault cleared by remote time delay tripping. The three-phase fault and the delayed tripping of many lines caused instability of generators within San Francisco and the blackout. Restoration took several hours. The disturbance affected major portions of San Francisco including San Francisco International Airport. The blackout was featured on national news.

A report provided to CEPEL, Eletrobrás, and ONS discusses the oversight roles of the California ISO and California Public Utilities Commission over PG&E operations and maintenance.

The June 25, 1998 MAPP and Northwestern Ontario cascading disturbance

This disturbance was in the eastern rather than western North American interconnection. It's described here because of lessons that can be learned. Five islands were formed during the disturbance. The event started in the Minneapolis, Minnesota area of the Mid-continent Area Power Pool (MAPP) network.

The disturbance fortunately occurred during the early morning hours. Power transfers were high into the Minneapolis area from the west and north, and from the Minneapolis area to the south and east. The Minneapolis/St. Paul Twin Cities export to the east and south was1004 MW. The major lines are a 345-kV line going south and a 345-kV line going east.

During a lightning storm the south line tripped at 0134 hours, and could not be reclosed because of high phase angle across the open breaker. Protection prevented closing for phase angles greater than 40 degrees. The actual angle was slightly higher.

At 0218 hours the east line tripped because of a lightning-caused single-phase fault. Underlying 115-kV and 161-kV lines subsequently tripped, leading to cascading and formation of four islands separate from the eastern interconnection. The Northwestern Ontario network eventually went black. The MAPP region lost over 4,000 MW of generation and over 300 MW of load. Northwestern Ontario lost 650 MW of load.

Following the outage of the south line, the system operated outside operating limits, and return to safe operation did not occur in the time allowed by MAPP standards (10 minutes). Especially considering the thunderstorm conditions, operator were at fault. Operators attempted to reduce transfers by line loading relief measures associated with open-access commercial power trading procedures. These procedures were not adequate for the emergency conditions. We could argue that automatic measures should be required for such conditions.

One terminal of the south line is at a nuclear plant and instantaneous reclosing is not used. Some form of automatic reclosing or single-pole switching could be considered to improve reliability during lightning storms.

Restrictions on phase angle limits should be carefully considered.

The North American Electric Reliability Council (NERC) requires each region or subregion to have Security Centers. (If there is an ISO, the security center is at the ISO.) The MAPP Security Center operator was not sufficiently aware of the system conditions following the south line outage. The utility operators at a different control center were focused on restoration of the south line. The recommendation was made that the Security Center implement a dynamic security assessment tool to assess current system conditions and verify adequate stability margins.

Appendix 2: BPA Protective Relay Practices

This appendix and the following appendix may be of interest in regard to possible improvements following the March 11 Brazilian power failure. BPA practices, however, may not always be applicable in other power systems. There is usually more than one right way.

Bus arrangements and protection: For 500-kV, breaker-and-one-half bus configurations are used for large stations. Ring busses are used for small stations and are converted to breaker-and-one-half configuration as new lines are added. With breaker-and-one-half arrangement, a bus fault can be cleared without interrupting any transmission lines. Bus differential and local breaker failure relaying is always used.

Transmission faults followed by failure of a middle circuit breaker sometimes results in a severe disturbance. In such a situation, BPA may operate with the middle breaker open (Figure A2.1).

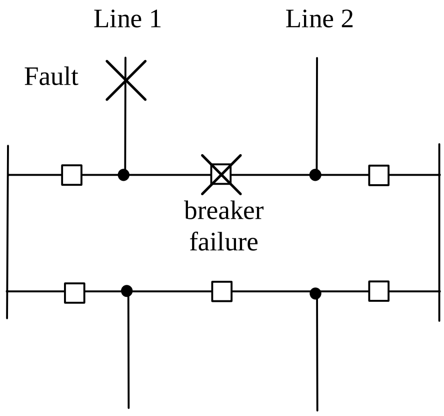

Fig. A2.1. Breaker-and one-half arrangement. If breaker failure of the middle breaker with outage of line 2 causes a problem, the middle breaker can be operated open.

Main and transfer bus (sometimes termed main and auxiliary bus) configurations are used for 230-kV and lower voltages. Some of the 230-kV busses are very important, and may include several sections connected by normally-closed bus sectionalizing circuit breakers. The main and transfer bus arrangement includes an additional circuit breaker that can be used if another circuit breaker is out for maintenance. Bus differential relaying is *always* used for each bus section. Local breaker failure relaying is always used.

Because of poor reliability of circuit breakers employing pre-insertion resistors, new circuit breakers are simpler, without pre-insertion resistors [13]. Modern metal oxide varistor surge arresters limit switching overvoltages. Older circuit breakers are replaced, or have pre-insertion resistors removed, on a case by case basis.

Line protection: 500-kV and other important lines have redundant high-speed protection. Starting in the 1960s, BPA developed an extensive microwave radio system used for transfer trip, SCADA, AGC, voice, and other functions. Microwave availability is around 99.99%. Recently, BPA has also developed a fiber optic network, justified mainly by expected revenue from selling capacity. Utility-owned microwave was chosen in part because of poor experience with power line carrier, which can be affected by short circuits, and because of poor experience with telephone company owned communications.

BPA's standard transmission line protection scheme is combined direct underreaching, permissive overreaching transfer trip. For phase faults, zone 1 and 2 distance relays are used. For ground faults, directional ground instantaneous and time overcurrent relays are used. Ground distance relays available with digital relay packages may be used, but the directional ground time-overcurrent relays are essential for low magnitude ground faults.

BPA uses single-pole switching on most 500-kV lines. This is a low-cost means to improve reliability since circuit breakers have independent pole (phase) operation, and because relay packages include single-pole switching capability. A "hybrid" switching method is used on some lines to ensure secondary arc extinction: the line is initially tripped single phase, and then opened three phase for about 15 cycles on the backswing of the electromechanical rotor oscillations [15].

Out-of-step relaying: BPA employs out-of-step relaying at selected locations such as on the Pacific AC Intertie. BPA policy for 500-kV lines is to "trip-on the-way-in" to avoid a zero voltage condition as the electromechanical swing reaches 180 degrees. Circuit breakers must be capable of out-of-step tripping duty.

Appendix 3: BPA Restoration Practice

BPA restoration practice involves opening all circuit breakers, forming small generation-load islands, and then interconnecting the islands. Several tests were performed in the 1980s involving charging 500-kV lines from hydro generation, and picking up aluminum potline load. The aluminum electrolysis load with diode rectifiers has favorable voltage sensitivity similar to resistive load.

BPA's operator training simulator (developed by EPRI) is valuable for training operators in restoration.

Appendix 4: WSCC Disturbance-Performance Table Of Allowable Effect On Other Systems (1)

Performance Level (2)	Disturbance (2) Initiated By: No Fault 3ϕ Fault With Normal Clearing SLG Fault With Delayed Clearing DC Disturbance (3)	Transient Voltage Dip Criteria (4) (5)	Minimum Transient Frequency (4) (5)	Post Transient Voltage Deviation (4)(5)(6)	Loading Within Emergency Ratings	Damping
A	Generator One Circuit One Transformer DC Monopole	Max V Dip – 25% Max Duration of V Dip Exceeding 20% – 20 cycles	59.6 Hz Duration of f Below 59.6 Hz – 6 cycles	5%	Yes	>0
B	Bus Section	Max V Dip – 30% Max Duration of V Dip Exceeding 20% – 20 cycles	59.4 Hz Duration of f Below 59.4 Hz – 6 cycles	5%	Yes	>0
C	Two Generators Two Circuits DC Bipole	Max V Dip – 30% Max Duration of V Dip Exceeding 20% – 40 cycles	59.0 Hz Duration of f Below 59.0 Hz – 6 cycles	10%	Yes	>0
D	Three or more circuits o common ROW			Cascading Is Not Permitted		
E	Loss of multiple 500 kV or higher circuits (3 or more) that cross one another at 1 location Loss of 3 or more circuits that share a common linkage Loss of entire plant with 3 or more generating units Loss of entire substation Loss of multiple circuits, multiple generators, or circuits and generators that have no common mode of failure			Evaluate for risks and consequences		

(1) This table applies equally to either of the following:
(a) A system with all elements in service; or
(b) A system with one element removed and the system adjusted.

(2) Specifies the minimum allowable performance on other systems for a disturbance. Blackouts, voltage collapse, or cascading are not allowed unless the initiating disturbances and corresponding impacts are confined to either a radial system or a local network. The examples of initiating disturbances in this table provide a basis for estimating a performance level to which a disturbance not listed in this table would apply.

(3) Includes disturbances which can initiate a permanent single or double pole DC outage.

(4) Maximum transient voltage dips and duration, minimum transient frequency and duration, and post transient voltages deviations in excess of the values in this table can be considered acceptable if they are acceptable to the affected system or fall within the affected system's internal design criteria. The transient frequency must remain below the indicated frequency for more than six cycles to be considered a violation.

(5) Transient voltage and frequency performance parameters are measured at load buses (including generating unit auxiliary loads), however, the transient voltage dip should not exceed 30% for any bus. Allowable post-transient voltage deviations apply to all buses.

(6) If it can be demonstrated that post transient voltage deviations that are less than these will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem. Simulation of post transient conditions will limit actions to automatic devices only and no manual action is to be assumed.

Appendix 5: List of Documents Delivered by Carson Taylor

[BPA97] **G. Lee and B. Mittelsadt (Editors)**, "Blue Ribbon Panel - Comments on the Bonneville Power Administration System Reactive Study", May 1997

[Bunch99] **R. Bunch and D. Kosterev**, "Design and Implementation of AC Voltage Dependent Current Order Limiter at Pacific HVDC Intertie", *1999 IEEE PES Summer Meeting*, Alberta, Canada, July 1999

[CPUC99] **California Public Utilities Commission**, "CPUC, EOB Staffs Issue Reports On PG&E December 8 Outage", March 1999

[FURNAS97] **Divisão de Estudos Especiais da Operação / FURNAS**, "Instalação de um Limitador de Mínimo na Tensão Ud do Elo de Corrente Contínua", *Nota Técnica*, 1997

[Hauer97] **J. Hauer, D. Trudnowski, G. Rogers, B. Mittelstadt, W. Litzenberger and J. Johnson**, "Keeping an Eye on Power System Dynamics", *IEEE Computer Applications in Power*, October 1997

[Hauer98] **J. F. Hauer and C. W. Taylor**, "Information, Reliability and Control in the New Power System", *American Control Conference*, Philadelphia, PA, USA, June 24-26, 1998

[Kezunovic99] **M. Kezunovic and I. Rikalo**, "Automated Analysis of Protective Relay Operation", *Annais of Intelligent System Application to Power Systems (ISAP'99)*, pp. 93-, Rio de Janeiro, Brazil, April 4-8, 1999

[Kosterev97] **D. N. Kosterev, C. W. Taylor and W. A. Mittelstadt**, "Model Validation fo the August 10, 1996 WSCC System Outage", *IEEE Transactions on Power Systems*, 1997

[Kosterev97b] **D. Kosterev, S. Yirga and M. Venkatasubramanian**, "WSCC Disturbance Validation Final Report for the Power System Outage that Occurred on the Western Interconnection on August 10, 1996 at 1548 PAST", *Prepared by Validation Work Group (VWG) under direction of the Operating Capability Study Goup (OCSG)*, April 1997

[Legate88] **A. C. Legate, J. H. Brunke, J. J. Ray, E. J. Yasuda**, "Elimination of Closing Resistors on EHV Circuit Breakers", *IEEE Transactions on Power Delivery*, Vol. 3, No. 1, pp. 223-231, January 1998

[NERC97] **NERC**, "NERC Planning Standards", September 1997

[NERC98] **NERC Operating Committee**, "NERC Policy 2 - Transmission", January 1998

[Smith98] **B. Smith**, "WSCC July and August 1996 Disturbances Lessons Learned and Follow-up", *(Draft version)*, June 1998

[Taylor97] **C. W. Taylor and D. C. Erickson**, "Recording and Analysing the July 2 Cascading Outage", *IEEE Computer Applications in Power*, January 1997

[Taylor98] **C. W. Taylor and R. Ramanathan**, "BPA Reative Power Monitoring and Control Following the August 10, 1996 Power Failure", *VI SEPOPE*, IP - 003, Salvador, BA, Brazil, May 24-29, 1998

[USDOE96] **U. S. Department of Energy**, "The Electric Power Outages in the Western United States, July 2-3, 1996 - Report to the President", Washington, DC, USA, August 1996

[VanZandt97] **V. VanZandt, M. Landauer, W. Mittelstadt and D. Watkins**, "A Prospective Look at Reliability with Lessons from the August 10, 1996 Western System Disturbance", *IERE Workshop Directions in Power System Reliability*, Palo Alto, CA, USA, May 1-2, 1997

[WICF99] **Western Interconnection Coordination Forum**, "Organizational Alternatives for Western Interconnection Grid Manafement", March 1999

[WSCC96] **WSCC Operations Committee**, "WSCC Disturbance Report For the Power System Outages that Occurred on the Western Interconnecion on July 2-3, 1996", September 1996

[WSCC96b] **WSCC Operations Committee**, "WSCC Disturbance Report For the Power System Outages that Occurred on the Western Interconnecion on August 10, 1996 1548 PAST", October 1996

[WSCC97] **WSCC**, "WSCC Planning Standards", *(Draft Version)*, 1997

[WSCC98] **WSCC**, "Voltage Stability Criteria, Undervoltage load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology", May 1998

[WSCC98b] **WSCC**, "WSCC Operating Procedures Update and Revisions", January 1998

[WSCC99] **NERC**, "NERC/WSCC Reliability Standards Compliance Program", March 1999

[WSCC99b] **WSCC**, "WSCC Reliability Criteria", March 1999

Appendix 6: Example of a BPA Nomogram