Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FREEDOM OF INFORMATION ACT PROGRAM

July 11, 2023

In reply refer to: FOIA # BPA-2023-00924-F

SENT VIA EMAIL ONLY TO: m_hess23@uni-muenster.de

Martin Heßler, PhD Candidate
Institute of Theoretical Physics
University of Münster Wilhelm-Klemm-Straße 9
48149 Münster
Germany

Dear Mr. Heßler:

This communication is the Bonneville Power Administration's (BPA) final response for agency records made under the Freedom of Information Act, 5 U.S.C. § 552 (FOIA). Your request was received on May 1, 2023 and formally acknowledged on June 16, 2023.

Request

"… the two [Western Electricity Coordinating Council] WECC reports and the frequency time series for the 2/3 July 1996 outage event or even identify the unknown dataset as one of the time series of this event."

Response

BPA searched for and gathered records responsive to your request. BPA collected 118 pages of responsive records from knowledgeable agency personnel in Transmission Operation Control. Those 118 pages accompany this communication, release in full with no redactions applied.

Appeal

The records release certified above is final. Pursuant to 10 C.F.R. § 1004.8, you may appeal the adequacy of the records search, and the completeness of this final release, within 90 calendar days from the date of this communication. Appeals should be addressed to:

Director, Office of Hearings and
Appeals HG-1, L'Enfant Plaza
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585-1615

The written appeal, including the envelope, must clearly indicate that a FOIA appeal is being made. You may also submit your appeal by e-mail to OHA.filings@hq.doe.gov, including the phrase "Freedom of Information Appeal" in the subject line. (The Office of Hearings and Appeals prefers to receive appeals by email.) The appeal must contain all the elements required by 10 C.F.R. § 1004.8, including a copy of the determination letter. Thereafter, judicial review will be available to you in the Federal District Court either (1) in the district where you reside,(2) where you have your principal place of business, (3) where DOE's records are situated, or (4) in the District of Columbia.

Additionally, you may contact the Office of Government Information Services (OGIS) at the National Archives and Records Administration to inquire about the FOIA mediation services they offer. The contact information for OGIS is as follows:

Office of Government Information Services
National Archives and Records Administration
8601 Adelphi Road-OGIS
College Park, Maryland 20740-
6001 E-mail: ogis@nara.gov
Phone: 202-741-5770
Toll-free: 1-877-684-6448
Fax: 202-741-5769

Questions about this communication may be directed to Brian Roth, Case Coordinator, at bsroth@bpa.gov or 503-23-7621. Questions may also be directed to James King, FOIA Public Liaison, at jjking@bpa.gov or (503) 230-7621.

Sincerely,

Candice Palen
Freedom of Information/Privacy Act Officer

Responsive agency information accompanies this communication

WESTERN SYSTEMS COORDINATING COUNCIL

DISTURBANCE REPORT

For the Power System Outages
that Occurred on the Western
Interconnection on —

JULY 2, 1996 1424 MAST

JULY 3, 1996 1403 MAST

Approved by the WSCC Operations
Committee on September 19, 1996

DISTURBANCE REPORT TASK FORCE MEMBERS

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Robert Sparks, PG&E
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Tom Yohn, PSC

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System Identifiers

Throughout the report, organizations are identified using the acronyms listed below.

AEPC – Arizona Electric Power Cooperative, Inc.
APS – Arizona Public Service Company
BPA – Bonneville Power Administration
BCHA – British Columbia Hydro and Power Authority
CLPD – Clark Public Utilities
CSU – Colorado Springs Utilities
EPE – El Paso Electric Company
EWEB – Eugene Water & Electric Board
IPC – Idaho Power Company
IID – Imperial Irrigation District
LDWP – Los Angeles Department of Water and Power
MWD – Metropolitan Water District/Southern California
MID – Modesto Irrigation District
MPC – Montana Power Company, The
NEVP – Nevada Power Company
NAPG – North American Power Group, Inc.
NCPA – Northern California Power Agency
OXGC – Oxbow Geothermal Corporation
PG&E – Pacific Gas and Electric Company
PAC – PacifiCorp
PASA – Pasadena, City of
PEGT – Plains Electric Generation and Transmission Cooperative, Inc.
PRPA – Platte River Power Authority
PGE – Portland General Electric Company
PSC – Public Service Company of Colorado
PNM – Public Service Company of New Mexico
CHPD – PUD No. 1 of Chelan County
COPD – PUD No. 1 of Cowlitz County
DOPD – PUD No. 1 of Douglas County
GCPD – PUD No. 2 of Grant County
POPD – PUD No. 1 of Pend Oreille County
SNPD – PUD No. 1 of Snohomish County
PSPL – Puget Sound Power & Light Company
RDNG – Redding, City of
RVSD – Riverside, City of
SMUD – Sacramento Municipal Utility District
SRP – Salt River Project
SDGE – San Diego Gas & Electric Company
SNCL – Santa Clara, City of
SCL – Seattle Department of Lighting (Seattle City Light)
SPP – Sierra Pacific Power Company
SCE – Southern California Edison Company
TCL – Tacoma Department of Public Utilities (Tacoma City Light)
TAUC – TransAlta Utilities Corporation
TSGT – Tri-State Generation & Transmission Association, Inc.
TEP – Tucson Electric Power Company
TID – Turlock Irrigation District
USBR – U.S. Department of Interior Bureau of Reclamation
- USDO – (Denver Office)
- USGP – (Great Plains)
- USLC – (Lower Colorado)
- USMP – (Mid-Pacific)
- USPN – (Pacific Northwest)
- USUC – (Upper Colorado)

USCE – U.S. Army Corps of Engineers (North Pacific Division)
UMPA – Utah Municipal Power Agency
VERN – Vernon, City of
WWPC – Washington Water Power Company
WAPA – Western Area Power Administration
- WAHQ – (Golden, Colorado)
- WALC – (Phoenix, Arizona)
- WALM – (Loveland, Colorado)
- WAMP – (Sacramento, California)
- WAUC – (Salt Lake City, Utah)
- WAUM – (Billings, Montana)

WKP – West Kootenay Power Ltd.
WPE – WestPlains Energy

I. EXECUTIVE SUMMARY AND INTRODUCTION

The Western Interconnection and Western Systems Coordinating Council

The Western Interconnection encompasses a vast area of nearly 1.8 million square miles. The Western Interconnection is embodied within the Western Systems Coordinating Council (WSCC) region, which is the largest and most diverse of the nine regional reliability councils of the North American Electric Reliability Council (NERC). WSCC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. The region is naturally divided into four major areas — Northwest, Rocky Mountain, Arizona-New Mexico, and California-Southern Nevada, which reflect varying, and sometimes extreme, geographic and climatic conditions. Transmission lines span long distances between large generating plants at remote locations and widely separated population centers. These lines have the capability to transfer power over great distances — such as from Canada to Mexico. High voltage transmission lines span the region from the verdant Pacific Northwest with abundant hydroelectric resources to the arid Southwest with large coal-fired and nuclear resources. Consequently, the WSCC network may be characterized as a sparse network in contrast to the densely connected network of the Eastern Interconnection.

Due to the vastness and diverse characteristics of the region, WSCC's members are faced with unique and challenging problems in coordinating day-to-day interconnected system operation and the long-range planning needed to provide reliable and affordable electric service to more than 59 million people, representing approximately 20 million customers, in WSCC's service territory. These unique problems call for innovative solutions to ensure a reliable and an economically efficient regional interconnected electric system.

To safeguard the reliability of interconnected electric system operation, numerous technical studies are conducted each year to reasonably ensure that critical operating conditions are thoroughly studied and evaluated. These studies include assessments of low probability events that are expected to result in system islanding and scattered underfrequency load shedding. Islanding and underfrequency load shedding are protective actions required for severe low probability disturbances to stabilize the system, minimize customer interruptions, and allow rapid system restoration. These are all fundamental ingredients in preserving reliability in the West. The western interconnected system is designed to protect itself and minimize customer outages when unforeseen or unexpected incidents or situations occur.

In addition to its technical study activities, WSCC instituted a compliance monitoring program in 1995 in which individual member systems are evaluated by review teams to ensure compliance with WSCC and NERC reliability criteria, operating policies, and guides. In short, WSCC places the highest priority on maintaining reliability; operating within established WSCC and NERC reliability criteria, policies, and guides; and providing the essential coordination among entities within the Western Interconnection to achieve these reliability standards.

July 2, 1996 System Disturbance

At 2:24 p.m. Mountain Advanced Standard Time (MAST) on July 2, 1996, a flashover occurred between a 345,000-volt transmission line and a tree that had grown too close to the line. This line extends for 234 miles between the Jim Bridger generating plant near Rock Springs, Wyoming, and the Kinport substation in southeastern Idaho (see Exhibit 1). Protective devices detected the problem and de-energized the line in three cycles (1/20 second). Normally, this would have been the only event and should not have caused any problems on the interconnected system.

However, a protective device on the parallel Jim Bridger-Goshen 345,000-volt line also detected the problem and erroneously interpreted it as a similar problem on its own line. The device operated improperly to de-energize the second line. Disconnecting two lines from service, nearly simultaneously, greatly reduces the capability of the system to carry power out of the Jim Bridger generating plant. To keep from overloading the system and to maintain system reliability, another protective scheme (known as a "remedial action scheme") automatically shut down two of the four generating units at the Jim Bridger generating plant. This remedial action scheme operated correctly as designed. These actions should not have caused any problems on the interconnected system.

Prior to the loss of the two 345,000-volt lines, the two Jim Bridger generating units that automatically disconnected were providing about 1,000 megawatts of generation to Idaho Power Company and PacifiCorp. (The four-unit Jim Bridger generating plant is jointly owned by the two companies.) The entire power plant output just prior to the disturbance was approximately 2,000 megawatts. Most of the energy was being used in southeast Idaho and Utah. When the two units were removed from service, the burden on other generators throughout the Western Interconnection increased. As the inertia of these generators increased power output, their rotational speed slowed down. The system frequency dropped from 60 Hz (cycles per second) to 59.9 Hz. In response to the decreasing frequency, within seconds, the speed governors on the generating unit turbines throughout the Western Interconnection opened control valves to increase the steam flow (thermal generating units) or water flow (hydro units) into the turbines to arrest the frequency decline.

The interconnected electric transmission system responded to support this redistribution of generation. Initially, the voltages in the Idaho load area and on a section of the 500,000-volt California-Oregon alternating current (AC) Intertie (COI) in southern Oregon began to decline but gave no indication of collapse. Approximately two seconds after the Jim Bridger units were disconnected, the Round Up-LaGrande 230,000-volt line in Oregon was disconnected due to a malfunctioning relay. Voltages continued to decline and 21 seconds later, the Mill Creek-Antelope 230,000-volt line between Montana and eastern Idaho was automatically de-energized. The Mill Creek-Antelope line was tripped by a protective device that detected low voltage and high current on the line.

During the period following the Bridger unit trips and the Mill Creek-Antelope 230,000-volt line trip, flows from Oregon to Idaho on the Midpoint-Summer Lake 500,000-volt line increased by about 500 megawatts. Approximately 70 percent of the additional flow came from northern Oregon on the John Day-Summer Lake section of the COI and 30 percent came because of decreased flows to California on the Summer Lake-Malin section of the COI. Also, in conjunction with the Mill Creek-Antelope trip, voltages in the Boise, Idaho area and at substations on the COI in southern Oregon began to decline rapidly with corresponding increased reactive flow from California to Oregon.

Approximately three seconds later, protective devices responded to the declining voltage condition and operated automatically to disconnect the four 230,000-volt transmission lines between Boise and the Brownlee substation in western Idaho. Approximately two seconds later, protective devices at the Malin and Captain Jack substations, responding to the extremely low voltage condition, automatically disconnected the California-Oregon AC Intertie, which consists of three 500,000-volt lines extending from the Pacific Northwest into California. De-energizing those lines interrupted the flow of more than 4,000 megawatts of power from the Northwest into California.

Protective Actions to Stabilize the System

At this point, the system was becoming unstable. Like the wheels of a car on an icy road that have lost traction and the car begins sliding back and forth, the generators in various parts of the Interconnection were on the verge of sliding out of synch with one another. If this sliding out of synch were allowed to progress, the power generated by those units would be unable to reach the customers, the power system voltages would fluctuate severely, equipment could be damaged, and consequently the entire interconnected system in the West could collapse, blacking out all 59 million people. However, the Western Interconnection has been designed with multiple layers of protection to respond to low probability, unanticipated outages that have progressed beyond those that are normally handled without customer interruption.

The dynamics of the sparse network in the West require these special automatic protection systems to allow economic yet reliable interconnected system operation. When an outage progresses to the level of that experienced on July 2, protection systems are automatically initiated to allow the system to bend but not break. This means that scattered customer outages will occur; however, the majority of customers will not be affected and the system will be positioned for rapid recovery and restoration of electric service to those customers who experience loss of electric service. Over 2 million customers were interrupted on July 2, representing about 10 percent of the total customers served throughout the Western Interconnection. Most of those interrupted were restored within a few minutes to half an hour.

To contain an outage of this type and prevent equipment damage from occurring, special protective devices are installed at many locations. As in the analogy of the car on an icy road, automatic operation of these devices enables the wheels to regain traction and allows the driver to regain control of the vehicle without suffering serious consequences. These devices detect the impending loss of synchronism and separate the interconnected generation and transmission system into electrical “islands.”

An electrical island is an area, large or small, disconnected from the rest of the system. The philosophy of dividing into electrical islands is to minimize customer outages and restoration times. Within each island, there are generating plants, customers, and a transmission system to carry the power from the plants to the customers. However, the generation on-line in each island may not match the customer demand for electricity (load) in the island. If the island was importing power before the breakup, the generation will be insufficient to match the demand for electricity and the frequency within the island will decrease. If the frequency is allowed to drop too far, the generating units within the island could be damaged. To prevent this damage, protective devices would automatically disconnect the units and the entire island may be blacked out.

To prevent a complete blackout, utilities have also installed “underfrequency relays” to interrupt electric service to some of their customers and thereby preserve service to the majority. When a sufficient amount of electric service has been interrupted so that the remaining customer demand for electricity matches the generation in the island, the island stabilizes. Some customers will be without power, but most will remain in service. This process minimizes the number of customers who will be without power, prevents further loss of generation, and enables rapid restoration of the system and customer electric service in a controlled and timely manner.

In the absence of these underfrequency relays, electric generating plants would become unstable and become disconnected from the system in a random uncontrolled manner, much like the car sliding out of control on the icy road. The system would most likely experience a complete blackout (loss of all generation and loss of electric service to all customers) and most customers would be without power for hours during the slow process of restoring generating plants to full operation. (When thermal generating plants are shut down, it takes hours to bring them back on-line due to the high temperatures and pressures that must be attained to generate electricity.) In the July 2 incident, most customers that were interrupted, representing about 10 percent of the total customers in the region, were without power for only a matter of minutes and generally less than 30 minutes.

If the island was exporting power before the breakup, its frequency will rise because the energy being generated exceeds the energy needs of the customers. To regain control of the system and balance the supply of electricity with demand, selected generating units are automatically disconnected in a controlled manner according to design before they can be damaged or cause system instability. Other units rapidly reduce their generation output to assist in restoring the system frequency.

<u>Formation of Electrical Islands</u>

On July 2, five of these electrical islands were formed to stop the progression of the outage, stabilize the system, minimize customer interruptions, and enable fast restoration of the system and customer service.

One large island included California, Arizona, Southern Nevada, New Mexico, the El Paso, Texas, area, and northern Baja California. This island had been importing power before the disturbance, so it was deficient in generation and therefore its frequency declined. Electric service to approximately 1,183,000 customers (about 4,484 megawatts of customer load) was interrupted to balance customer demand with electricity supply, minimize customer outages, and avoid uncontrolled outages of generation and blacking out the entire island. One line of the California-Oregon Intertie was restored to service in about 30 minutes, with the other two lines following within another ten minutes. Customer service restoration began immediately following the breakup, and most customers were restored within 20 to 30 minutes after losing service.

Another large island contained Oregon, Washington, northern Idaho, Montana, British Columbia, and Alberta. The island had been exporting large amounts of power to the rest of the Interconnection, so it was surplus in generation and therefore its frequency rose. Consequently, some generating units were automatically disconnected to balance generation and customer demand for electricity. Approximately 7,452 customers (100 megawatts) were interrupted for a period ranging from minutes to about one hour.

The third island consisted of Utah, Colorado, most of Wyoming, and western South Dakota and western Nebraska. Before the island was separated from the larger island to the south and west, it shed a large block of load by underfrequency load shedding. Later on, additional load was shed manually. In all, about 3,348 megawatts of customer load (approximately 572,860 customers) was interrupted within the island due to underfrequency or manual load shedding. This load was restored within minutes up to six hours.

A fourth island was formed in southern Idaho and a small part of eastern Oregon, where virtually all customer load and generation was interrupted when the voltage collapsed. A small portion of Bonneville Power Administration load remained connected to six western Idaho generators that remained on line. A portion of PacifiCorp's load in southeastern Idaho remained in this island and was blacked out. About 3,368 megawatts of load (425,000 customers) was interrupted. Because Idaho experienced a near blackout, it took until 8:45 p.m., more than six hours, to restore all customers in this island.

The fifth island was in northern Nevada, where Sierra Pacific Power Company lost nearly 550 megawatts of customer load (61,700 customers). Underfrequency load shedding prior to separation from California was responsible for about 250 megawatts of this total. The remainder was due to transient low voltage caused by the power swing and underfrequency encountered later during restoration. All customers were restored to service over a period ranging from minutes for most to slightly more than three hours for a very few.

<u>July 3, 1996 System Disturbance</u>

On July 3, 1996, at 2:03 p.m. MAST, a similar chain of events began. The Jim Bridger-Kinport 345,000-volt line again experienced a flashover as the line came into close proximity with the same tree. The line was automatically disconnected by protective devices, clearing the short circuit. (Crews patrolling the line had not yet been able to identify the cause of the July 2 flashover). At nearly the same time, the Jim Bridger-Goshen 345,000-volt line was automatically disconnected due to misoperation of the same protective device that misoperated on July 2. The outage of two of the three 345,000-volt lines west of the Jim Bridger generating plant triggered the remedial action scheme, automatically disconnecting two of the four Jim Bridger units.

However, operating conditions on July 3 were different from those on July 2. Interchange schedules through Idaho from the Northwest were reduced, generation patterns were changed in the Northwest and Idaho, and schedule limits on the California-Oregon Intertie were temporarily reduced. In addition, the Brownlee No. 5 generating unit in western Idaho was returned to service following a forced outage and was providing additional voltage support.

As was anticipated, the generation deficiency created by the outage of the two Jim Bridger units was replaced by increased output from other generating units throughout the Western Interconnection. Voltage on the heavily loaded 230,000-volt system between the Brownlee area (on the Snake River along the Oregon-Idaho border) and the Boise, Idaho, area began to decline and stabilized at a near-normal voltage of 224,000-volts.

The Brownlee hydro generating plant in western Idaho increased to maximum reactive output to provide critical voltage support for the Boise area. Alarms in the plant control rooms were triggered, indicating the units were at their maximum excitation limits. The plant operators, seeking to reduce local plant stress, lowered generating plant reactive output away from the limits to a less stressed operating level for the units. This action further induced declining voltages in the Boise area.

The Idaho Power Company system operators recognized the potential for an incident similar to that of July 2, and manually interrupted electric service to some customers in the Boise area. This prompt action prevented a repeat of the July 2 voltage collapse in the Boise area and contained the disturbance to the Idaho Power Company system. All customer load was restored within one hour, except an interruptible industrial customer that was restricted to half load until the Jim Bridger generation was restored at about 5:30 p.m.

Preliminary Findings

Both the July 2 and 3 disturbances were initiated by a flashover between the Jim Bridger-Kinport 345,000-volt line and a tree that had grown too close to the line. The tree has since been removed.

The faulty protective device on the Jim Bridger-Goshen 345,000-volt line was also identified and removed from service after the July 3rd disturbance. Redundant primary protective devices remained in service to protect the line.

Immediately following the July 2 disturbance, engineers began assessing the disturbance events and conducting computer simulations to determine the cause of service interruptions and system islanding. Study efforts are ongoing to investigate the Idaho load area voltage collapse, the voltage collapse on the California-Oregon AC Intertie in southern Oregon, and other related issues. If the system had operated as designed and intended, disconnecting the two Jim Bridger units should have been the last significant event that occurred. There should have been no loss of customer load and no system islanding.

The investigation revealed that the system operating conditions were unusual and had not been identified as a problem. The events of July 2 revealed that these conditions had not been adequately studied to identify the problems that were encountered. The simultaneous combination of operating conditions on July 2 was characterized by:

- near record setting hydro generation continuing into the summer season
- high imports into the Northwest from Canada
- high north-to-south power transfers on the California-Oregon AC and DC Interties
- transfers from the Northwest to Idaho and Utah, and
- high coal-fired generation in Wyoming and Utah during record peak summer electricity demands in Idaho and Utah.

Although these conditions were unusual, the transmission system was being operated within known operating constraints. Studies that were conducted after the disturbance were used to establish interim lower simultaneous power transfer limits to ensure system reliability, and those conservative limits have been implemented. Additional studies are being conducted to determine root causes of service interruptions and islanding and to determine what is required to achieve maximum power transfer limits and still maintain system reliability.

Overview and Primary Conclusions

The WSCC members make a concerted effort to avoid system-wide disturbances, and have designed and implemented an economically efficient system that limits the impact to scattered customer outages across a large geographic area. As with any complex system, it is not economically feasible or even possible to guarantee 100 percent reliability. The disturbance on July 2 progressed to a degree of severity that is rarely seen. About 10 percent of WSCC's total customers were affected, and yet the system and service to affected customers was quickly restored in most areas. As with any incident of this type, there are lessons to be learned. This event will be critically reviewed and appropriate steps taken to further lessen the potential occurrence and impact of similar events in the future. As part of the disturbance analysis and review process, WSCC will evaluate its procedures, policies, and monitoring activities to ensure that any necessary improvements are identified and expeditiously implemented.

A summary of the primary conclusions and recommendations is as follows:

1. On July 2, portions of the system were unknowingly being operated in a manner that was not in compliance with the WSCC Minimum Operating Reliability Criteria. The July 2 disturbance was initiated by a flashover on the Jim Bridger-Kinport 345,000-volt line. Nearly simultaneously, a protective device on the Jim Bridger-Goshen 345,000-volt line misoperated, thus de-energizing the line and initiating a remedial action scheme which tripped two units at the Jim Bridger generating station. The initial line fault, protective device misoperations, inadequate voltage support, and unanticipated system conditions led to cascading outages causing interruption of customer loads and islanding.

2. Following the events leading to voltage collapse in the Idaho load area and on a section of the 500,000-volt California-Oregon AC Intertie in southern Oregon on July 2, the automatic controlled islanding and underfrequency load shedding programs operated to minimize customer outages and system restoration time.

3. WSCC and its members will thoroughly reevaluate their processes for identifying unusual operating conditions and potential disturbance scenarios and make the necessary changes required to more effectively ensure that the conditions and potential disturbances are adequately studied prior to encountering them in real-time operating conditions.

4. WSCC and its members will review the current processes for assessing the potential for voltage instability and the need to enhance the existing operator training programs, operational tools, and annual technical assessments. This will improve the ability to predict future voltage stability problems prior to their occurrence, and to mitigate the potential impacts to prevent incurring adverse effects on a regional scale. A study group has been formed comprised of Bonneville Power Administration, PacifiCorp, Idaho Power Company, other interested utilities, and the WSCC Staff to conduct technical studies simulating the conditions that were encountered on July 2. This group will have use of the best available technical tools and analysis techniques as well as experienced and knowledgeable experts in voltage stability. The WSCC members have a substantial body of knowledge and understanding of the voltage stability phenomenon.

5. The WSCC Operations Committee will review the status of implementing the recommendations made in the NERC publication entitled "Survey of the Voltage Collapse Phenomenon" and make appropriate assignments to review and ensure that the recommendations made in this publication have been appropriately implemented within the Western Interconnection.

The complete list of conclusions and recommendations of the disturbance task force are set forth in the following section.

II. CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations were developed by the disturbance task force. Completion of each recommendation will be ensured by the Compliance Monitoring and Operating Practices Subcommittee of the WSCC.

1. Conclusion: The simultaneous combination of operating conditions on July 2, characterized by record peak summer loads in Idaho and Utah, maximum water flow conditions in the Pacific Northwest, high north-to-south transfers on the California-Oregon AC and DC Interties, transfers from the Northwest to Idaho and Utah, high transfers from Canada to the Northwest, and high thermal generation in Wyoming and Utah were not anticipated or studied. The speed of this collapse seen July 2 has not been observed in this region and was not anticipated in studies.

   Although power transfers were within known limits at the time of the disturbance, portions of the system were unknowingly being operated in a manner that was not in compliance with WSCC Minimum Operating Reliability Criteria. The WSCC criteria state —

   > "Multiple contingency outages of a credible nature will be examined, and the system will be operated to protect against general system instability, uncontrolled separation or cascading outages for these contingencies....
   >
   > Proper control of reactive supply and reactive generation, provision of adequate reactive supply reserve, and maintenance of adequate voltage levels on the transmission system are required to maintain high stability limits and good service.... Systems and control areas shall ensure that reserve reactive resources are adequate to maintain minimum acceptable voltage limits under facility outage conditions."

   Insufficient voltage support in the Northwest and Idaho for the operating conditions of July 2 was a primary factor that contributed to the widespread impact of this disturbance. The initiating event, the near simultaneous outage of two Jim Bridger 345,000-volt lines, should not have resulted in the system separations and loss of load experienced on July 2, 1996.

   Recommendation:

   a. Idaho Power Company, PacifiCorp, Bonneville Power Administration (BPA), and other Northwest area entities shall reduce scheduled transfers to a safe and prudent level until studies have been conducted to determine the maximum simultaneous transfer capability limits and to thoroughly evaluate operating conditions actually observed on July 2.

Status: A temporary operating nomogram was developed and implemented to ensure that simultaneous transfers on the AC Intertie and the Midpoint-Summer Lake line are at safe and prudent levels.

b. Idaho Power Company shall conduct studies to determine acceptable generation dispatch and scheduling to prevent susceptibility to southern Idaho voltage instability and shall evaluate the adequacy of reactive power supply for the support of its operation. Corrective measures shall be developed and implemented.

Status: Interim operating procedures have been implemented to restrict flows on the Brownlee-Boise Bench lines and maintain reactive reserves for loss of two Bridger units.

c. COI owners, BPA, PacifiCorp, Idaho Power Company, WSCC Staff and other appropriate WSCC members, shall form an ad hoc study group to duplicate the conditions of July 2 in order to study the conditions that existed at the time of the disturbance leading to the voltage collapse of the AC Intertie. Corrective measures shall be developed and implemented. This group shall report to the WSCC Planning Coordination Committee/Operations Committee (PCC/OC) Joint Guidance Committee.

Status: A study group has been formed comprised of Bonneville Power Administration, PacifiCorp, Idaho Power Company, other interested utilities, and the WSCC Staff to address this recommendation. This group will have use of the best available technical tools and analysis techniques as well as experienced and knowledgeable experts in voltage stability. The WSCC members have a substantial body of knowledge and understanding of the voltage stability phenomenon.

d. Conclusions and recommendations shall be developed from the studies performed in response to Recommendation 1.b. and 1.c. and shall be presented in a stand alone report, requiring the same approval process and recommendation progress tracking as this disturbance report.

e. The WSCC PCC/OC Joint Guidance Committee shall again review the recommendations made in the NERC publication entitled "Survey of the Voltage Collapse Phenomenon." In light of the July 2 disturbance, the WSCC Operations Committee shall make appropriate assignments to review and ensure that the recommendations made in this publication have been appropriately implemented within the Western Interconnection.

Status: In the spring of 1992, WSCC initiated a reporting program to annually summarize potential voltage stability problems and measures that are being taken to address the problems throughout the WSCC region. Reports were issued to WSCC's Technical Studies Subcommittee in each of the years from 1992 through 1995. The 1996 report is in preparation.

The first recommendation from the NERC publication on voltage collapse is in regard to training programs for system operators, plant operators, and system planners. This subject is addressed in WSCC's Dispatcher Training Program and many WSCC system operators and planners have attended seminars and workshops on voltage collapse. At least one WSCC utility has had training activities for power plant operators. BPA and Pacific Gas and Electric Company (PG&E) have implemented operator training simulators for dispatcher training that incorporate voltage collapse scenarios.

The second recommendation from the NERC publication addresses the consideration of voltage collapse phenomena in regional and utility planning and operating criteria. Although more work is necessary, many individual utilities have voltage collapse criteria and the subject is addressed in WSCC's reliability criteria. Many WSCC members routinely analyze voltage collapse as part of planning and operating studies, and potential voltage collapse often defines power transfer limits.

The third recommendation from the NERC publication addresses testing and enhancing the reactive power capability of generating units. Public Service Company of Colorado has done significant work and was able to "reclaim" 500 MVAR of generator reactive power capability. (A paper titled "Field Assessment of Generators Reactive Power Capability was produced by A. Panvini and P.J. Yohn — paper number 94 WM 214-7 PWRS.) The US Bureau of Reclamation and other utilities have also been active in this area. Much more work needs to be done, including developing models and data for overexcitation limiters.

The fourth recommendation from the NERC publication addresses the implementation of remedial measures. WSCC utilities have been active in this area. Examples (not exhaustive) are as follows.

Five utilities in the Puget Sound area developed and implemented special operating procedures to prevent voltage collapse. The procedures include monitoring of cross-Cascade Mountains power imports, automatic load tripping for double-circuit 500-kV line loss, reactive power sources optimization, gas turbine generator operation, and rotating load curtailment.

In December 1991, five utilities in the Puget Sound area implemented undervoltage load shedding covering 15 percent of load (1,800 MW of peak winter load). Undervoltage load shedding is being implemented in the Portland, Willamette Valley, and Southwest Washington areas, with additional utilities participating. Portions of the Puget Sound undervoltage load shedding area have operated to reduce the impact of local problems.

Many WSCC utilities have installed series capacitors, SVCs, mechanically switched capacitor banks, and other reinforcements to prevent voltage collapse.

PG&E implemented an undervoltage load shedding scheme in the Fresno area in 1992. When activated, this scheme can interrupt up to 195 MW of load.

Arizona Public Service Company (APS) currently installs undervoltage relays for first contingency outages which studies indicate result in unacceptable voltage levels. APS is also installing capacitors in the system for additional reactive support.

Undervoltage load shedding, installed by Salt River Project, mitigated the effects of the July 29, 1995, Phoenix area voltage problem.

El Paso Electric Company designed a mitigating measure to prevent uncontrolled system voltage collapse. This mitigating measure is a load shedding scheme utilizing time-delay undervoltage relays to operate feeder/substation circuit breakers.

Public Service Company of New Mexico (PNM) has been aware of a voltage stability problem in the Northern New Mexico (NNM) area since 1993. Based on the results of studies, a Reactor Tripping Scheme (RTS) has been implemented. Nomogram limits have been revised based on voltage stability limits using QV analysis.

British Columbia Hydro and Power Authority (BC Hydro) has implemented load tripping based on voltage and synchronous condenser reactive power output.

BC Hydro and BPA are implementing control center on-line voltage security assessment.

The fifth recommendation from the NERC publication calls for changes to the NERC Operating Policies to reflect voltage collapse issues. WSCC members have followed the NERC policies. The past chairman of the NERC Operating Committee was from the WSCC region and was very active in Northwest Power Pool voltage collapse issues and coordination of NERC policy changes within WSCC.

The sixth recommendation from the NERC publication calls for industry efforts toward improved modeling and analysis of the voltage collapse phenomena. Here, WSCC engineers have been industry leaders on an international basis.

f. The WSCC Operations Committee shall assess whether the levels and allocation of operating reserves contributed to the severity of this disturbance and implement corrective measures as appropriate.

2. Conclusion: WSCC and its member systems conduct hundreds of studies each year to assess system reliability and prepare for varying seasonal operating conditions. However, the unusual combination of operating conditions and disturbance conditions encountered on July 2 were not anticipated in studies conducted prior to the disturbance.

   Recommendation: The WSCC PCC/OC Joint Guidance Committee shall thoroughly review WSCC's and its members' processes for studying upcoming system operating conditions. Any changes will be implemented as needed to ensure that these processes for identifying unusual operating conditions are appropriate, and that credible disturbances are adequately studied prior to encountering them in real-time operating conditions.

3. Conclusion: Relay misoperation on the Jim Bridger-Goshen 345,000-volt line contributed to the initiating event of the disturbance. This faulty relay was not identified and corrected until after the event on July 3.

   Recommendation:

   a. PacifiCorp shall remove, replace, or modify the ground relay at Bridger that failed.

   Status: The relay has been disabled and repairs are in progress.

   b. PacifiCorp and Idaho Power Company shall determine the cause of the relay failure and implement corrective measures. Testing and maintenance procedures shall be reviewed to determine any deficiencies and corrective measures implemented. Deficiencies in relay design or application shall be determined and disseminated to the relay manufacturer and WSCC members and corrective measures shall be implemented on all 345,000-volt Jim Bridger lines.

   c. PacifiCorp shall determine why the relay problem on the Jim Bridger-Goshen line was not identified and corrected prior to the July 3 event. Measures shall be implemented to quickly identify and rectify relay problems prior to the occurrence of subsequent events.

   Status: After the July 2 disturbance (1424 MAST), system restoration was given priority. This disturbance caused the four Bridger units to be tripped off line and almost all line breakers to be tripped open by relay action in substations in PacifiCorp's eastern Idaho and western Wyoming regions. It takes time to sort out the details and determine the instigating cause. Next priority was placed on data collection. Requests were made for field personnel to obtain relay targets and oscillograms. The following day (July 3) oscillograms from the Goshen and Bridger substations were received. These oscillograms indicated that a relay protecting the Goshen line may have misoperated during the fault on the Kinport line (July 2, 1424 MAST). Later that day, relay target and SER (sequence-of-events recorder) information was received. This additional information aided in identifying the ground unit of the Westinghouse SPCU relay at Bridger as the cause of the misoperation. This conclusion was not reached in time to take the relay out of service, which would have prevented the July 3 disturbance.

d. The WSCC Reliability Subcommittee shall expeditiously complete its assignment to develop reliability criteria addressing the issue of relay failure.

e. The WSCC Relay Work Group shall expeditiously implement a data base or some other effective means to track significant relay problems and disseminate this information to WSCC members for their information.

4. <u>Conclusion</u>: Low system voltage caused the operation of protective relays to trip the Mill Creek-Antelope line, the four Boise Bench-Brownlee lines, and the Malin-Round Mountain #1 and #2 lines.

   <u>Recommendation</u>: Montana Power Company, Idaho Power Company, and BPA should review the application and settings of the relays for their respective lines and make changes where appropriate.

5. <u>Conclusion:</u> The relay on the Round Up terminal of the 230-kV LaGrande line failed in the phase-to-phase trip-active mode, and only needed the fault current detector relay to operate. When flows increased towards Idaho following the loss of Bridger generation, the relay timed out and tripped the line. This was an undesirable relay action.

   <u>Recommendation</u>: BPA should determine the cause of the failure and correct it.

   <u>Status</u>: The relay was last calibrated in March 1996. When inspected after the July 2 event the trip contact for the phase-to-phase unit was found closed. The relay was replaced and the failed unit was evaluated. It was found that a relay element (the SC autotransformer) did not have one phase potential on it. There were no visible breaks in the relay's internal wiring. After breaking open a crimp sleeve at the autotransformer, corrosion was found, explaining the reason for the high impedance dropping the voltage to the relay internals. BPA is consulting with a vendor regarding this problem.

6. <u>Conclusion:</u> The Jim Bridger 345,000-volt transmission system is known to sustain a higher than normal number of single line-to-ground faults. The line-to-ground faults on the Jim Bridger-Kinport 345,000-volt line on both July 2 and 3 resulted from a flashover when the line sagged too close to a tree, which was located about 97 miles east of Kinport. The tree that caused this problem was found on July 5 and was cut down.

   <u>Recommendation</u>:

a. Idaho Power Company and PacifiCorp shall continue to investigate the cause of the relatively high incidence of single line outages and implement measures to reduce the frequency of outages.

Status: In years prior to this outage, PacifiCorp and Idaho Power Company have been actively investigating the cause of the higher than normal single line-to-ground faults on the Bridger lines. More outages have generally occurred on the Kinport and Borah lines compared to the Goshen line. Comparison of construction between the three lines, lightning studies, tower footing resistance measurements, switching surge analysis, contamination tests and measurements, insulator analysis, and bird behavior are among the studies that have been conducted to identify the cause of unexplained outages.

Prior to July 2, bird discouragers were installed on the Kinport line. Two insulators have been added to each leg of the insulator V-strings on the Kinport and Borah lines on most of the towers in the high outage areas. Additional grounds were added to some towers on the Kinport and Borah lines.

A review of the three Bridger lines conducted by Idaho Power Company and independent inspectors following the disturbance concluded that there are several bird nests in the structures on the Bridger lines in the areas examined, which is consistent with previous bird studies. The porcelain and glass insulators were generally in good operating condition in the areas examined.

Facility additions to the Bridger system have reduced the effect of a single line outage and state-of-the-art traveling wave fault locator relays have been installed to more accurately examine individual faults.

b. PacifiCorp shall determine why the tree, which resulted in the flashover on the Jim Bridger-Kinport 345,000-volt line, was not identified and removed prior to the incident on July 3, and revise their procedures to enable a more timely response should similar incidents occur in the future.

c. PacifiCorp shall review their tree trimming procedure and report actions taken to CMOPS.

7. <u>Conclusion:</u> Underfrequency generator protection was not fully coordinated with underfrequency load shedding in the Colorado area, northern Nevada area, and possibly in other areas. This problem was primarily noted with regard to Independent Power Producers (IPPs), however, is not limited to IPPs.

   <u>Recommendation:</u> The WSCC OC shall oversee a complete review of underfrequency load shedding coordination with underfrequency generator protection and implement corrective measures.

8. <u>Conclusion</u>: Grant County PUD has recently installed over frequency tripping to protect their units at Wanapum and Priest Rapids. Their relays were set to trip

units at 60.5 Hz. These units did trip during the July 2 outage. This setting appears to be too conservative and may not be in the best interest of the transmission system.

Recommendation: Grant County PUD and BPA should review the appropriateness of the over frequency trip setting and make appropriate corrections if required.

Status: Grant County PUD has reset these relays to 62 Hz.

9. Conclusion: McNary tripped five of the ten units on line (310 MW) due to loss of excitation relay action. In addition, CJ Strike tripped three units (78 MW) due to field excitation overcurrent.

   Recommendation:

   a. BPA should work with U.S. Army Corps of Engineers (USCE) to determine whether the units at McNary actually lost excitation, and if so, why?

      Status: Prior to July 2nd, at high excitation levels, the phase unbalance circuitry was sensitive to noise and the USCE was working with the manufacturer on corrections. Modification of voltage regulators on units 1 through 12 and 14 was completed on August 16th and 17th. Changes were made to prevent tripping on over excitation during system disturbances. Work is in progress to change taps on all 13.8/230-kV transformer banks to increase 230-kV voltage.

   b. Idaho Power Company shall review the effectiveness of the excitation system at CJ Strike and implement corrective measures.

      Status: Excitation systems at all three units at CJ Strike are scheduled to be replaced during the Fall of 1996.

   c. The Control Work Group shall establish testing procedures to establish power and reactive limits on generating units. A testing interval should also be determined.

10. Conclusion: Five electrical islands were formed due to system separations created by the disturbance which stabilized the system while minimizing the number of customers affected, and containing the disturbance. These islands include:

    a. California, southern Nevada, northern Baja California, Arizona, New Mexico, and a small portion of western Texas and Mexico (Island 1);

    b. Alberta, British Columbia, Washington, Oregon, northern Idaho, and Montana (Island 2);

c. Utah, Colorado, Wyoming, western South Dakota, and western Nebraska (Island 3);

d. Idaho and a small part of eastern Oregon (Island 4); and

e. northern Nevada (Island 5).

<u>Recommendation</u>:

a. WSCC's Controlled Islanding Ad Hoc Group shall expeditiously complete its assignment to assess the adequacy and appropriateness of controlled islanding within the WSCC region to prevent uncontrolled separations and undesirable loss of generation and customer load. This study shall include an assessment of the impact on this disturbance of the Northeast/Southeast Separation Scheme being out of service. Following approval, recommendations made by the group shall be promptly implemented.

b. The WSCC Operations Committee shall oversee a review of out-of-step tripping and out-of-step blocking within the WSCC region to evaluate adequacy. This includes:

   1) out-of-step relays that operated;
   2) out-of-step relays that did not operate but should have; and
   3) out-of-step conditions that caused operation of impedance relays.

11. <u>Conclusion:</u> Underfrequency load shedding appeared to operate correctly within Islands 1 and 5 to minimize the number of customers affected, preserve on-line generation, and allow for rapid and orderly system restoration. However, distribution of load shedding region wide was disproportionate. Underfrequency load shedding began in some areas, including northern Nevada, Utah, Colorado, and Wyoming before the islands were completely formed. No underfrequency load shedding occurred in Island 2 (frequency was high). Underfrequency load shedding in Island 3 operated as designed, however the system was slow to recover and approached the timer settings for tripping some units for generator underfrequency protection. Island 4 experienced a complete blackout due to voltage collapse. Load was shed in Island 4 due to insufficient voltage rather than underfrequency load shedding.

<u>Recommendation</u>:

a. All WSCC members experiencing low frequency in this disturbance shall confirm that underfrequency load shedding operated properly and was appropriately coordinated among entities within each island. Deficiencies shall be reported to WSCC and corrective measures implemented.

<u>Status</u>: In Island 1, Los Angeles Department of Water and Power, City of Glendale, and City of Burbank, all of whom have 59.1 Hz load shedding steps,

shed no load. Frequency plots from Los Angeles Department of Water and Power's Energy Control Center (see Exhibit 5) show the local frequency envelope decaying to just above the 59.1 Hz setting. The plots show frequencies below 59.1 Hz for a few cycles, but it is not clear if these few points, which differ significantly from the overall trend, are reliable. Even if those measurements are reliable, LDWP uses industry-standard underfrequency relays with inherent six cycle time delays, and the frequency did not remain below 59.1 Hz for the required six cycles.

LDWP engineers surmise fortunate electrical location, coupled with high injections from local in-basin generation and Sylmar Converter Station, “stiffened” the local area just enough to prop up the frequency and avoid shedding load. LDWP’s electrical neighbor, SCE, did not shed all of its 59.1 Hz block, further suggesting that, in some parts of Southern California, frequency was just at - or above - the trip frequency.

Following the disturbance, LDWP protection engineers tested the settings and the performance of the underfrequency relays on LDWP’s 59.1 Hz load shedding step and found them to be correct.

b. The WSCC Operations Committee shall initiate a study to review the coordinated underfrequency load shedding programs on a regional scale. It is envisioned that a comprehensive study of this type could take as long as two years to complete. Recommendations shall be developed and implemented.

c. The Colorado/Wyoming Off Normal Frequency group, to include Utah, shall study the underfrequency coordination of load shedding with generator tripping in Island 3 and recommend measures that will ensure system operators are aware of pertinent operating constraints.

12. <u>Conclusion:</u> The voltage collapse in the Idaho Power Company system on July 2 resulted in a blackout of the IPC system. On July 3, IPC dispatchers demonstrated the viability of load shedding in preventing voltage collapse.

<u>Recommendation:</u> IPC shall consider implementing automatic undervoltage load shedding programs to prevent the spread of voltage collapse. Other WSCC members shall learn from IPC’s experience and also give consideration to implementing undervoltage load shedding programs as appropriate. WSCC members shall report to WSCC Staff the measures implemented.

13. <u>Conclusion:</u> Load was manually shed in Island 3 due to excessive loss of generation within the island. Excess generation was available outside of the island. Once interties were reestablished, load restoration occurred quickly. The interties were reestablished in about 1½ hours.

Recommendation: Entities within the island shall study intertie re-establishment procedures to determine if faster restoration of ties can be accomplished and facilitate more rapid restoration of service to customers.

Status: Area utilities met on August 8, 1996 and addressed communication problems. Procedures will be implemented to ensure proper statement of conditions and resource requirements during all communications activities. Public Service Company of Colorado will continue to track and report status for Island 3.

14. Conclusion: In general, WSCC member system operating personnel responded quickly to inform WSCC regarding the disturbance, enabling WSCC to inform the Department of Energy (DOE), news media, and others requiring information. Some member systems were not timely in reporting the effects of the disturbance on their systems directly to the Department of Energy.

    Recommendation: Although most member systems responded quickly to WSCC, the overall process of communicating WSCC disturbance information to WSCC, DOE, NERC, and the media shall be thoroughly reviewed by the Communications and Operations Committees to identify where improvements can be made in the timeliness and accuracy of information reported.

15. Conclusion: The slow response time of several utilities in submitting data to the disturbance evaluation task force on significant events impeded the understanding of this event and caused misinformation to be distributed to other utilities and the news media.

    Recommendation: The WSCC Operations Committee shall oversee the development of a standard procedure that will facilitate the timely and accurate assimilation of data and preparation of technical reports.

16. Conclusion: In general, WSCC member system operating personnel responded quickly to restore the system following the disturbance. The majority of interrupted customers throughout the West were restored within minutes. Because the IPC system experienced a near blackout, restoration of that system required considerably longer.

    Recommendation: Idaho Power Company shall review its restoration procedures to determine if any enhancements can be made and implement improvements as deemed appropriate.

17. Conclusion: At 1616 MAST, Idaho Power Company and Sierra Pacific Power Company attempted to restore the Humboldt-Midpoint 345,000-volt line. Idaho closed the Midpoint end of the Humboldt-Midpoint line; however, high voltage in Idaho (at Midpoint) prevented closing the tie at Humboldt.

Recommendation: SPP and IPC shall investigate the cause of the high voltage at Midpoint and take corrective measures.

18. Conclusion: On July 3, the Brownlee plant operators received excitation limit alarms and became concerned about the amount of reactive power being supplied by their units. As a result the operators placed the voltage regulators in "manual" operation, and reduced the voltage set point. Although this action did relieve stress on the generating units, it was undesirable from an interconnected system standpoint in that it reduced reactive support to the Boise area which contributed to the need for manual load shedding to arrest declining voltage.

Recommendation:

a. IPC shall ensure that their generating plant operators recognize the potential implications of their actions on interconnected system operations. Other WSCC member systems shall learn from IPC's experience and implement training measures as appropriate to recognize voltage problems and the action to be taken to preserve reliability. WSCC members shall report to WSCC Staff the measures implemented.

Status: Individual training has been given to plant operators at Brownlee regarding reactive support of generating units during outages and a memorandum of instruction has been posted at their workstations. A class for the plant operators has been scheduled to discuss procedures during outage conditions.

b. The WSCC Control Work Group and WSCC Staff shall develop appropriate training materials for distribution to plant operators, including the operators of IPPs.

19. Conclusion: The Stegall and Virginia Smith AC-DC-AC ties in western Nebraska were ramped in the wrong direction by operating personnel 13 minutes into the disturbance, sending power from west to east, aggravating the generation deficiency in the Colorado/Wyoming/Utah island. This action may have contributed to unnecessary customer outages within the island. The incorrect operation was detected in less than one minute at Virginia Smith and within three minutes at Stegall, and correct east to west operation was initiated.

Recommendation: Correct operation for the conditions experienced as well as other possible scenarios shall be reinforced in training sessions with the Stegall and Virginia Smith AC-DC-AC tie operators.

20. Conclusion: Manual load shedding was required in the Public Service Company of Colorado control area due to loss of generation 20 minutes into the disturbance. Some excess generation was available in the other control areas; however, this was not available to PSC due to poor verbal communications among dispatchers during the disturbance. (Approximately 138 MW of load was

automatically restored in the island when frequency went high after separation from Island 1. This action may have prevented even more generation from tripping).

Recommendation:

a. Entities within the island shall analyze this communication problem and implement corrective measures.

Status: Area utilities met on August 8, 1996 and addressed communication problems. Procedures will be implemented to ensure proper statement of conditions and resource requirements during all communications activities. Public Service Company of Colorado will continue to track and report status for Island 3.

b. Entities in Island 3 that experienced generation loss shall determine the cause of the generator outages and implement measures to avoid loss of generation should similar conditions occur in the future.

Status: Public Service Company of Colorado will track and report status for Island 3.

21. Conclusion: This disturbance affected a wide geographic area and highlights the need for an improved security monitoring process within the Western Interconnection to monitor real-time operating conditions on a broader scale than is presently accomplished by individual control areas.

Recommendation:

a. WSCC's Security Process Task Force shall review what is required to implement a security monitoring process in the Western Interconnection, to monitor operating conditions on a regional scale and promote interconnected system reliability. The Task Force shall recommend appropriate actions.

b. WSCC's Security Process Task Force shall recommend the appropriate tools, such as on-line power flow, stability programs, and real time data monitors that can assess primary reliability indicators for frequency and voltage performance system-wide on a real-time basis. These tools should be able to record disturbance data for effective and timely determination of the cause and impacts of a disturbance of any type. A monitoring tool, the Wide Area Measurement System (WAMS), recorded system information and was instrumental in the disturbance analysis and provided useful information in evaluating the rapid voltage collapse on July 2, 1996.

22. Conclusion: During the disturbance investigation process, DOE and NERC raised the question as to whether diminishing expertise and reductions in personnel could have been contributing factors in this disturbance.

Recommendation: The WSCC Operations Committee shall assess to what degree the lack of expertise and reductions in personnel have had in contributing to this disturbance and make appropriate recommendations to maintain acceptable system performance.

23. Conclusion: The functional separation of the industry and addition of new players raises the question about strategies that are necessary to maintain system reliability. It is not clear what effects, if any, the current changes taking place in the electric utility industry involving deregulation and the marketing of power had in contributing to this disturbance.

    Recommendation:

    a. The WSCC Operations Committee shall assess to what degree the changes in the industry contributed to this disturbance and make appropriate recommendations to maintain acceptable system performance.

    b. The WSCC Operations Committee shall assess all other constraints potentially affecting reliability, including but not limited to, environmental and regulatory constraints, and shall recommend actions appropriate to maintaining an acceptable level of reliability.

24. Conclusion: DOE has raised questions as to whether or not changes are required to improve effectiveness of WSCC's policies, processes and procedures for ensuring reliability.

    Recommendation: The WSCC Board of Trustees shall review the council's polices, processes, and procedures, and identify any appropriate changes. WSCC shall implement the appropriate changes.

Observation by NERC Task Force Representatives: A NERC review shows that the WSCC members involved with the disturbance were, to their best knowledge, in overall excellent compliance with NERC Operating Policies. The July 2nd event was a double contingency for which the policies allow for some load shedding to prevent cascading. As complete shutdown occurred in Idaho and eastern Oregon Island, NERC's Operating Policy stating that complete shutdown should not occur for this type of event was unknowingly violated. This resulted from the unusual set of operating conditions and several subsequent line outages that occurred. Increased importance and attention must be given to NERC Operating Policy 6 Section C "Automatic Load Shedding" to prevent system collapse for multiple contingency events of this nature.

III. CONDITIONS PRIOR TO THE DISTURBANCE

The weather throughout the region was clear and dry with high summertime temperatures. Many utilities were experiencing very high loads, and some were approaching all-time peak loads. An abundant water supply in the Pacific Northwest made a great deal of low-cost surplus energy available to the rest of the region. The California-Oregon Intertie (COI) was carrying 4,260 MW south into California and the Idaho Power Company 230-kV system was moderately loaded in the west-to-east direction. The Midpoint-Summer Lake 500-kV line was carrying approximately 195 MW into Idaho.

The WSCC transmission system was being operated within all known transfer limits (see Exhibit 4 which shows actual flows prior to the outage and corresponding key path ratings).

At approximately 1410 MAST, schedule changes within the western interconnection caused approximately 100 MW of additional flow on the Midpoint-Summer Lake 500-kV line and caused Boise voltage to drop 1.3 percent.

There were few facilities out of service before the disturbance; however, approximately two minutes before the disturbance-initiating event, the Goshen-Grace 161-kV line in southeastern Idaho tripped on a phase-to-ground fault, reclosed and tripped again. It was still out of service when the disturbance began. The facilities out of service prior to the disturbance are listed in the following tables.

<u>Predisturbance Conditions</u>

Abnormal System Conditions

1. Abnormal system conditions that may have contributed to the occurrence or impact of the disturbance. In particular, list reactive devices that were out of service or limited in response capability.

Island 1

AEPC	none
EPE	none
IID	none
MID	none
NEVP	none
PG&E	none
SCE	Midway-Vincent #3 500-kV line series capacitor bank segment #1 at Vincent bypassed
SMUD	SMUD's Elk Grove feeder number 4 underfrequency relay was out of service prior to the disturbance. Approximately 30 MW of load was not tripped due to the underfrequency relay being out of service.

WALC none
WAMP none

Island 2

BCHA none
BPA none
COPD none
SCL none
WWPC none

Island 3

PRPA PRPA had set a new all time peak load at HE 1400. Voltages were down slightly. Rawhide was boosting 65 MVARS.
PSC none -- The new Fort Saint Vrain 130 MW CT #2 was on-line but not fully tested and adjusted, e.g., voltage regulator on manual.
WACM none
WALM none

Island 4

IPC

A) Brownlee Generating Unit #5 was out of service. This unit is a 250 MVA machine that is capable of producing roughly 100 MVAR of reactive support.

B) The regulator on one of the synchronous condensers at Boise Bench was not working properly. The condenser was left in service with its output fixed. This provided no dynamic support. The other condenser at Boise Bench was operating correctly.

Island 5

SPP - none

2. Describe abnormal system conditions that adversely impacted system restoration.

Island 1

AEPC none
EPE none
IID did not affect IID system; except that a 100 MW purchase from PAC was cut.
MID none
NEVP none
PG&E none
SCE none
SMUD none
WALC none
WAMP none

Island 2

BCHA	none
COPD	none
SCL	none
WWPC	none

Island 3

PRPA	none
PSC	none
WACM	none
WALM	Of six frequency sources available to Western's Loveland Area Office (LAO) dispatchers, two sources were dysfunctional and unusable by dispatch. One of the remaining meters was in the building on emergency generator power, not measuring the system frequency. Stegall AC-DC-AC Tie was ramped by TSGT 110 MW in the wrong direction for three minutes and then corrected to east to west. Virginia Smith AC-DC-AC Tie was ramped by LAO Dispatch 107 MW in the wrong direction for less than 1 minute, then corrected to east to west. LAO-SCADA failure during attempt to parallel on the TH 230/115-kV tie. Plus multiple SCADA restraints. Cause unknown. Thermopolis-562 synch-check relaying was inoperative, when closing by LAO SCADA was attempted. Old jumpers were found and removed on synch-check timer, which allowed synch-check relay to reset.

Island 4

IPC	none

Island 5

SPP	Sierra Pacific Power Company was isolated from the rest of the WSCC. While operating as an island, it was difficult to maintain frequency at or near 60 Hz while restoring load. In addition, Tracy Unit #2 was down for repairs which also limited the ability to restore all loads within the control area (while in an island).

Transmission Out of Service Prior to Outage

Island 1

AEPC	none
APS	none
EPE	none
MID	Los Banos-Westley 230 kV line
NEVP	none
PG&E	Midway-Vincent #3 500 kV line series capacitor bank @ Midway bypassed
	Midway-Vincent #1 500 kV line series capacitor bank segment #1 @Midway bypassed
	Los Banos-Midway #1 500 kV line series capacitor bank segment #1 @ Los Banos bypassed
	Los Banos-Midway #2 500 kV line series capacitor bank segment #2 @ Los Banos bypassed
PNM	none
SCE	Pardee-Moorpark #1 230 kV line
	Pardee-Vincent 230 kV line
SMUD	none
TID	No transmission out of service
WALC	No 69-kV or above lines out of services
WAMP	none

Island 2

BCHA	MSA-CKY 5L32
BPA	Hot Springs-Rattlesnake 1 230-kV line
	Green Valley-Fairview (of Alvey-Fairview 1) 230-kV line
	Franklin-Walla Walla 1 115-kV line
	Bell-Boundary 1 230-kV line
	North Bonneville-Ross 1 230-kV line
	Grand Coulee-Terminal of Midway-Grand Coulee 3 230-kV line
	Monroe-Snohomish 230-kV and PSPL SedroTap
COPD	none
EWEB	Bertelsen-Hawkins 115-kV line
	Lane-EWEB (WillCreek) 2 115-kV line
PACW	COPCO 2 230/115 Transformer
	Dixonville 500/230 Transformer
	St. Johns-View section of St. Johns-Merwin 115-kV line
	Eagle Point-Lost Creek section of Lone Pine-Prospect 115-kV line
PGE	Bethel-Round Butte 230-kV line
	Chemawa-PGE 2 57-kV line
SCL	East Pine-Broad St 120-kV cable
	Cedar Falls-Rattlesnake 120-kV line
WWPC	Benewah-Pincreek 115-kV (St. Maries-Pinecreek section)
	Dry Gulch-Pomeroy 69-kV

Island 3

PSC	Cameo-Parachute 230-kV line
WACM	Kayenta-Shiprock 230-kV series cap. bypassed
CSU	Midway-Nixon 115-kV line
WALM	Hoyt-Brighton 115-kV line
PACE	Goshen-Grace 161-kV line

Island 4

BPA	Teton-Lower Valley P+L 2 115-kV line
IPC	DRAM-Midpoint 230-kV line open ended at Midpoint
PACE	Goshen-Grace 161-kV line

Island 5

SPP	Falcon-Maggie Creek 120-kV line

Other Equipment Out of Service

Island 1

Island 2

BPA	Big Eddy 230/115-kV Transformer No. 1 (O/S damage 6/21/96)
	Lost Creek PH (forced due to PACW line construction)
	Vantage 500-kV bus reconfigured for construction

Island 3

PACE	Ben Lomond Synchronous Condenser

Island 4

Island 5

Voltages at Key Substations Prior to Outage

Island 1 Station	Voltage (kV)
APS	
Saguaro 500 kV Bus	511
Palo Verde 500 kV Bus	533.7
Westwing 500 kV Bus	523.1
San Manuel 115 kV Bus	114.8
Country Club 230 kV Bus	233.9
Cholla 500 kV Bus	530
Four Corners 500 kV Bus	528.4
Moenkopi 500 kV Bus	531.4
N. Gila 500 kV Bus	544.5
MID	
Parker	230.3
Standiford	113.9
NEVP	
Harry Allen 345 kV	347
PG&E	
Round Mt 500 kV	536
Table Mt 500 kV	535
Olinda 500 kV	548
Vaca Dixon 500 kV	534
Tracy 500 kV	537
Tesla 500 kV	526
Los Banos 500 kV	537
Gates 500 kV	539
Midway 500 kV	529
PNM	
West Mesa 345 kV	357.8
B-A 345 kV	357.8
Ojo 345 kV	356.7
San Juan 345 kV	355.3
SCE	
Devers 500 kV bus	521.5
Eldorado 500 kV bus	532.5
Lugo 500 kV bus	531.5
San Onofre 230 kV bus	230.7

Island 1 Station	Voltage (kV)
Vincent 500 kV bus	537.5
Serrano 500 kV bus	520.5
Big Creek 230 kV bus	240
SMUD Elverta 230 kV	230
Pocket 230 kV	230
TID Walnut 230 kV	233.32
WACM Shiprock 345-kV	353
Lost Canyon 230-kV	237
WALC Mead 500 kV, 230 kV	535, 235
Pinnacle Peak 345 kV, 230 kV	350, 232
WAMP Olinda 500 kV	549
Tracy 500 kV	529
Keswick 230 kV	236

Island 2 Station	Voltage (kV)
BCHA Ingledow 500 kV	527
Dunsmuir 500 kV	531
Malaspina 500 kV	539
Cheekye 500 kV	531
Nicola 500 kV	533
Mica 500 kV	536
Ashton Creek 500 kV	532
Revelstoke 500 kV	533
Selkirk 500 kV	537
Cranbrook 500 kV	535
Kelly Lake 500 kV	531
Glenannan 500 kV	533
Telkwa 500 kV	528
Skeena 500 kV	526
Williston 500 kV	530

Island 2 Station			Voltage (kV)	
G. M. Shrum 500 kV			523	
BPA	1400 MAST	1420 MAST	1424 MAST	1425 MAST
Malin 500-kV		540	538	529.6
Captain Jack 500-kV		542.8	540.9	530.3
Summer Lake 500-kV	551.3	543.2	541.6	528.9
Ponderosa 500-kV		540.8	540.8	529.5
Ponderosa 230-kV		242.6	242.5	237.8
Grizzly 500-kV		543.1	540.5	530.1
Buckley 500-kV		540	538	529
Slatt 500-kV		530	529	518
John Day 500-kV		536.6	535.3	526.4
Big Eddy 500-kV		535.4	533.7	527.2
Keeler 500-kV		538.7	536.8	533.4
Keeler 230-kV		240.1	239.7	239.6
Marion 500-kV		547.3	544.7	538.1
Hanford 500-kV		526.5	524.4	517
McNary 500-kV		518.1	516.7	510.3
McNary 230-kV		240.3	239.8	238.4
La Grande 230-kV		227.8	227.1	203.3
Hatwai 500-kV	538.6	539.3	538.3	529.5
Hatwai 230-kV	238	238.3		254.2
Garrison 500-kV		544.4	544.2	536.6
Garrison 230-kV		236.7	236.6	232.2
Boundary		236	235.5	233.6
Custer 500-kV		525.2	523.5	519.6
Raver 500-kV		545.3	544	540.5
COPD	122			
PACW Meridian 500-kV			545	
Dixonville 500-kV			546	
In general, voltages at key 230kV substations prior to the disturbance were within normal operating range of 1.0 to 1.02 p.u.				
Island 2 Station			Voltage (kV)	
SCL Bothell Sub. Bus #3			237.23	

Island 2 Station	Voltage (kV)
Duwamiah Sub. Bus #1	234.70
WWPC Beacon 230 kV	234.4
Behewah 230 kV	237.5
Cabinet 230 kV	239.7
Lolo 230-kV	235.2
Moscow 230-kV	233.9
N. Lewiston 230-kV	239.2
Noxon 230-kV	243.2
Pinecreek 230-kV	235.0
Rathdrum 230-kV	234.9
Westside 230-kV	235.1

Island 3 Station	Voltage (kV)
PACE Treasureton 230-kV	234
Ben Lomond 345-kV	349
Terminal 345-kV	349
Camp Williams 345-kV	352
Rock Springs 230-kV	228
Casper 230-kV	236
Thermopolis 230-kV	235
PSC Ute Grand Jct. 230-kV	240
Midway 230-kV	236
Comanche 230-kV	234
Ute Rifle 345-kV	351
Ute Rifle 230-kV	238
Rawhide 230-kV	230
Ault 345-kV	345
Ault 230-kV	229
Story 345-kV	359
Story 230-kV	241
Daniels Park 230-kV	232
Smoky Hill 230-kV	231

Island 3 Station	Voltage (kV)
Cherokee 230-kV	231
Pawnee 230-kV	236
Fort Saint Vrain 230-kV	227
Lookout 230-kV	227
WACM Vernal 138-kV	138
Midway 230-kV	237
Hayden 230-kV	237
Curecanti 230-kV	240
WALM Yellowtail 230-kV bus	235
Yellowtail 115-kV bus	118
Thermopolis 115-kV bus	114
Copper Mtn 115-kV bus	116
Boysen 115-kV bus	115
Big George 115-kV bus	119
Lovell 115-kV bus	112
Pilot Butte 115-kV bus	115
Badwater 230-kV bus	232
Basin 115-kV bus	115
Casper 115-kV bus	116
Seminoe 115-kV bus	111
Kortes 115-kV bus	114
Cheyenne 115-kV bus	112
Archer 115-kV bus	112
Happy Jack 115-kV bus	113
Warren Air Base 115-kV bus	112
Alcova 115-kV bus	116
Miracle Mile 115-kV bus	116
Glendo 115-kV bus	118
Stegall 230-kV bus	228
LRS 345-kV bus	350
LRS 230-kV bus	233
VSCS 230-kV bus	237
Ault 345-kV bus	345
Ault 230-kV bus	229

Weld 230-kV bus	228
Beaver Creek 115-kV bus	121
Gering 115-kV bus	114

Island 4 Station	Voltage (kV)
Borah 345-kV bus	350.5, HE 1400, 7/2
Bridger 345-kV bus	361.8, HE 1400, 7/2
Kinport 345-kV bus	358.8, HE 1400, 7/2
Brownlee 230-kV bus	231.8, HE 1400, 7/2
Boise Bench 230-kV bus	226.7, HE 1400, 7/2
Borah 230-kV Bus	234.4, HE 1400, 7/2
Brady 230-kV bus	235.5, HE 1400, 7/2
Hells Canyon 230-kV bus	233.9, HE 1400, 7/2
Kinport 230-kV bus	236.9, HE 1400, 7/2
Midpoint 230-kV bus	236.9, HE 1400, 7/2
Oxbow 230-kV bus	230.1, HE 1400, 7/2
Quartz 230-kV bus	229.9, HE 1400, 7/2
Boise Bench 138-kV bus	137.0, HE 1400, 7/2

Island 5 Station	Voltage (kV)
SPP Midpoint 345-kV*	352.4
Humboldt 345-kV	347.2
Gonder 230-kV	236.7
N Truckee 120-kV	120.7
Silver Peak 55-kV	58.2
Glendale 120-kV	119.6

*IPCo Midpoint Substation voltage telemetry picked up at SPPCo's ESCC

IV. DETAILED DESCRIPTION

At 1424:37 MAST on July 2, 1996, a disturbance occurred that ultimately resulted in the WSCC system separating into five islands and in service interruptions to over 2 million customers. Service was restored to most customers within 30 minutes, except on the Idaho Power Company (IPC) system, a portion of the Public Service of Colorado (PSC), and the Platte River Power Authority (PRPA) systems in Colorado, where some customers were out of service for up to six hours. On portions of the Sierra Pacific Power Company (SPP) system in northern Nevada, service restoration required up to three hours.

The first significant event was a single phase-to-ground fault at 1424:37.180 MAST on the Jim Bridger-Kinport 345-kV line. The fault occurred 97 miles east of Kinport and was caused by a flashover when the conductor sagged close to a tree. The line tripped, clearing the fault in three cycles.

Twenty milliseconds (ms) later, the Jim Bridger-Goshen 345-kV line tripped due to misoperation of the ground element in a relay at Bridger. The faulty relay was later identified as the ground sub-system of a Westinghouse SPCU relay and was removed from service. The component that failed was a local delay timer in the ground element. Redundant primary protective devices are in service to provide adequate protection.

Loss of the two lines correctly initiated a remedial action scheme (RAS) that tripped generating units 2 and 4 at Bridger (generating 1,040 MW total), bypassed the series capacitor at Burns and segment 3 of the Borah series capacitor, and inserted the 175 MVAR Kinport shunt capacitor.

Normal generation response to the frequency deviation (59.9 Hz), resulted in replacing the lost Bridger generation with generation from throughout the entire Western Interconnection.

The next recorded event (1424:38.995) was the tripping of the Round Up-LaGrande 230-kV line due to misoperation of a KD11 zone 3 relay at Round Up. Voltage at the LaGrande 230-kV bus dropped from 220-kV following the Bridger unit trips to 210-kV after the LaGrande line tripped. Investigation by BPA personnel revealed a faulty phase-to-phase impedance element. Careful investigation discovered corrosion under the crimp-on lug to the phase-to-phase voltage restraint element. This effectively resulted in an open restraint circuit which caused the phase to phase impedance element to close. The relay is supervised by a fault detector, so the failure was not apparent until a disturbance occurred that created enough current to operate the fault detector and lasted long enough for the relay to time out. The relay has been replaced. This relay was last tested and calibrated on March 9 of 1996. Corrosion of crimp-on lugs is not a common problem and is not one that would be detected by routine maintenance.

BPA began receiving low voltage alarms throughout its system. At 1424:42 the voltage at BPA's Anaconda Substation alarmed via SCADA at 219-kV and Rattle Snake alarmed at 224-kV. At 1424:47, 230-kV shunt capacitors at Anaconda closed in via a voltage control relay. In eastern Idaho, BPA's Lost River 69-kV alarmed at 63-kV, Heyburn alarmed 9 seconds later at 134-kV, and 3 seconds later Spar Canyon alarmed at 217-kV. In Eastern Oregon, McNary alarmed at 238-kV, and at 1424:45 LaPine alarmed at 114-kV and Harney at 109-kV. In southern Oregon, Warner reported high voltage (242-kV) at 1424:59.

The redistribution of flows which followed, resulted in 300 MW of increased loading on the 230-kV lines from Oregon and Washington to Idaho. Correspondingly, flows on the four Brownlee-Boise Bench 230-kV lines into the Boise area increased to 1320 MVA (900 amps at approximately 212-kV). Flows on the Antelope-Mill Creek 230-kV line between Montana and Idaho measured at the Mill Creek end, increased to 377 MVA (990 amps at approximately 220-kV). In addition, the flow on the Midpoint-Summer Lake 500-kV line increased by 400 MW into Idaho.

The Humboldt-Midpoint 345-kV line between northern Nevada and southern Idaho picked up 72 MW of the dropped Bridger generation (import into Sierra Pacific Power on the tie went from 304 MW to 232 MW). Of the 72 MW, 52 MW flowed into northern Nevada via the west SPP-PG&E ties, 4 MW via the east SPP-PACE tie and 4 MW via the south SPP-SCE ties. The remaining 12 MW came from Sierra's frequency response characteristic.

At approximately 1424:51, a CJ Strike unit tripped (26 MW) due to field excitation overcurrent. At approximately 1425:01 a second 26 MW unit tripped at CJ Strike for the same reason.

The Mill Creek-Antelope 230-kV line tripped at 1425:01.052. The line was tripped by a zone 3 impedance relay (timed out) at Mill Creek due to a high load condition entering into the 3 phase distance characteristic of the relay.

During the period following the Mill Creek-Antelope trip, the flow from Oregon to Idaho on the Midpoint-Summer Lake line increased an additional 100 MW (500 total increase). Approximately 70 percent of the additional flow came from northern Oregon on the John Day-Summer Lake section of the COI and 30 percent came because of decreased flows to California on the Summer Lake-Malin section of the COI.

Following the Mill Creek-Antelope line trip, about 23 seconds after the Bridger units tripped, the voltage began to collapse rapidly in the Boise, Idaho area and on the Oregon section of the California-Oregon Intertie. See Malin and Boise area voltage plots in Exhibit 3.

Also following the Mill Creek-Antelope line trip, reactive power flow on the Valmy-Midpoint 345-kV line showed a shift of 171 MVARS from Valmy in northern Nevada towards Midpoint, Idaho. This coincides with the beginning of the voltage collapse in the Boise area. The reactive power was primarily generated at Valmy units 1 & 2. Voltage at the Humboldt 345-kV station dropped 9 percent prior to 1425:06 (as captured by SCADA).

The low voltage enable for the Celilo DC RAS shunt capacitor bank insertion at Malin armed within 0.5 seconds from the Mill Creek-Antelope line trip.

At approximately 1425:02, the third unit at CJ Strike (26 MW) tripped due to field excitation overcurrent. In addition, two McNary units tripped (130 MW) at 1425:03.2 due to suspected loss of excitation. At 1425:05.5, another 60 MW unit at McNary tripped for the same reasons. At the same time as, or immediately after system separation, two more McNary Units tripped (120 MW).

The four Brownlee-Boise Bench 230-kV lines were tripped by impedance relays over the period from 1425:04.404 to 1425:05.237. The first two lines (#3 and #1) were tripped by reverse zone 3 impedance relays at Boise Bench. The third line (#2) was tripped by a zone 2 relay at Brownlee, and the last line (#4) was tripped by a permissive overreach scheme at both ends. The Oxbow-Lolo and Hells Canyon-Walla Walla 230-kV lines were tripped by zone 2 distance relays at 1425.05.504 and 1425:05.620 which separated the 230-kV path between the Northwest and Idaho.

At 1425:05.250, the Malin 500-kV shunt capacitor group 3 was switched into service via automatic voltage control. At 1425:05.700, the Harney-Redmond 115-kV terminal tripped on zone 1 and the Fort Rock Series Capacitors inserted on all three lines south of Grizzly 1-3 cycles later.

At Celilo, the PDCI was affected by the collapsing voltages. In an attempt to maintain power flows, the DC line controls automatically raised the line current. Once the maximum limit of 3100 amps was reached, the DC line was unable to maintain transfer levels and transfers reduced in conjunction with decreasing voltages. The effect of this action was to place further burden on the AC system.

At 1425:06.57 the Celilo DC-RAS controller armed for the 10 second sliding window algorithm No. 2. At 1425:06.72 Celilo detected an AC overload condition and the 20 minute power loss integrated algorithm level No. 1 initiated just prior to the Malin-Round Mountain line trips.

In the 5 second period prior to the California-Oregon Intertie separation, reactive flows increased from 400 to 2400 MVAR from California into Oregon as a result of collapsing voltages in southern Oregon. During this same period, Midpoint-Summer Lake reactive flows increased from 170 to 300 MVAR into Midpoint.

The separation of the California-Oregon Intertie began when the Malin-Round Mountain #2 500-kV line opened by relay action at Malin at 1425:06.787. This was followed six ms later by the opening of the Malin-Round Mountain #1 line at Malin. These lines were tripped by under-impedance switch into fault logic. Eighty seven ms later, the Captain Jack-Olinda 500-kV line was tripped by positive sequence (zone 1) relay action at 1425:06.880.

Loss of the California-Oregon Intertie triggered a remedial action scheme which tripped 2,447 MW of Northwest generation and inserted the Chief Joseph Dynamic Brake. In addition, a signal was sent to the out-of-service Four Corners NE/SE separation scheme.

At this point, flows on the Summer Lake - Malin line reversed to feed Summer Lake. At 1425:06.901 the Malin shunt capacitor group 4 inserted in response to the DC-RAS signal. In addition, the Fort Rock Series Capacitors inserted on all three lines south of Grizzly 1-3 cycles later.

At 1425:06.900, the Dillon-Big Grassy 161-kV line was tripped by an impedance relay, thus separating Montana from eastern Idaho.

The Midpoint-Summer Lake 500-kV line tripped at 1425:07.020 on a zone 1 positive sequence distance relay. This disconnected the 500-kV tie between southern Oregon and Idaho.

Following the Captain Jack-Olinda trip, the low voltage problem on the California-Oregon Intertie became a high voltage problem at Malin and the disturbance changed to transient stability except in Idaho, where the voltage had collapsed. The ensuing high voltage resulted in an arrestor failure at Malin on the PACW Summer Lake line reactor, and at 1425:07.217, the Summer Lake-Malin 500-kV line tripped by directional ground relay action. This was followed by the tripping of Captain Jack-Meridian 500-kV line at 1425:07.330 and the Grizzly-Summer Lake 500-kV line at 1425:07.344. The Captain Jack 500-kV PCB 4980 (Olinda line) cleared the adjoining positions due to breaker failure in the open position. The Malin 500-kV shunt capacitors tripped on overcurrent after 4 seconds. Malin PCB 4184 (for shunt capacitor group 4) began arcing around the breaker housing , causing the breaker to fail, which cleared the Malin north bus. Also, on shunt capacitor group 3, six capacitor cells, 37 fuses, and six fuse holders failed.

As a power swing started through northern Nevada toward southern Idaho, the voltage dropped rapidly on the north 345 kV tie. About 168 MW of northern Nevada load was lost during the transient low voltage (believed to be the result of motor contactors dropping out, etc.).

In northern Wyoming, the Yellowtail-Rimrock 161-kV and the Yellowtail-Billings and Yellowtail-Crossover 230-kV lines were tripped by out-of-step relay action between 1425:07.207 to about 1425:07.395, separating Wyoming from Montana.

The above line trips caused the formation of two islands. One island contained Montana, Washington, Oregon, northern Idaho, British Columbia and Alberta (Island 2). The other island contained the rest of the WSCC.

The Borah-Bridger 345-kV line tripped at 1425:07.329 separating the remaining Bridger generation from Idaho. At 1425:07.67, when frequency had dropped below 59.3 Hz for 0.1 second, Sierra's first step of underfrequency load shedding operated, dropping 160 MW of firm load.

The first trip between the Idaho-Utah regions occurred at 1425:07.760 when the Borah-Ben Lomond 345-kV line tripped on zone 1 at Borah. Although this line would normally be transfer tripped by the Treasureton out-of-step scheme, it actually tripped 70 ms before that scheme activated at 1425:07.790. The Treasureton scheme tripped the Treasureton-Brady 230-kV line, the Wheelon-American Falls 138-kV line, the three Treasureton-Grace 138-kV lines, separated the Jim Bridger 345 and 230-kV switchyards (the generators are tied to the 345-kV bus) and tripped PacifiCorp's Monsanto load in southeastern Idaho. These actions separated the PacifiCorp system in southeastern Idaho, leaving its loads on the north side of the split tied to the Idaho Power Company system. On the south side of the split, the PacifiCorp system in southeastern Idaho, Wyoming, and Utah remained tied together. At 1425:07.850, Jim Bridger unit 3 now isolated from any significant load, tripped.

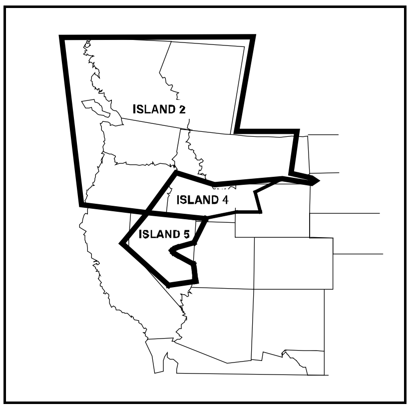
The frequency in northern Nevada (still part of the southern island) dropped an additional 0.1 Hz to just below 59.1 Hz. This resulted in picking up Sierra's second step of underfrequency load shedding, dropping 90 MW of additional firm load. At this time, southern Idaho and Utah were still tied via the northern Nevada transmission grid.

Isolated from most of its generation, the remaining southern Idaho load was now being fed via northern Nevada. The flow on the Humboldt-Midpoint 345-kV line went from 304 MW into Nevada (pre-disturbance) to 364 MW into Idaho just prior to Valmy-Coyote Creek tripping (a shift of 670 MW). This was made up by Sierra's other ties picking up 165 MW, 250 MW of underfrequency load shedding, 168 MW of load loss due to transient low voltage, and 87 MW in Sierra's frequency and power swing response (of which 80 MW was an increase in generator output).

At 1425:08.138, the Valmy-Coyote Creek 345-kV line in northern Nevada tripped. In northern Nevada, the Ft. Churchill-Austin 230-kV line was tripped by a zone 1 distance relay at 1425:08.150. This made the final separation between southern Idaho and Utah and separated northern Nevada's bulk system from the Utah system.

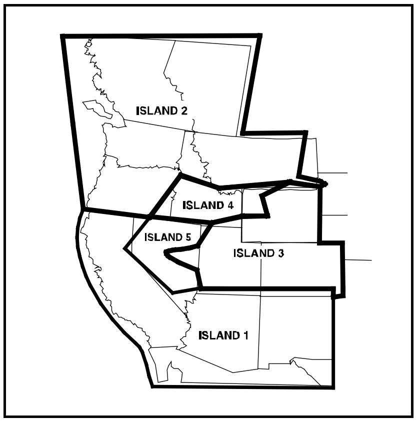
In southern Idaho, the Idaho Power Company system continued to break up and lose load due to low voltage. The Kinport-Midpoint 345-kV line tripped at 1425:08.156. At 1425:08.167, the Borah-Adelaide-Midpoint #1 line tripped, followed by the #2 line at 1425:08.182. This effectively separated the backbone transmission system between eastern and western Idaho. Approximately 300 to 400 MW of generation in southern Idaho was still on line at this time. Idaho and Nevada continued to be tied together through the 120-kV system in series with the 345-kV line from Coyote Creek to Midpoint.

Both Idaho and Nevada were still tied to the southern island through Sierra's ties to California via the weak California-Summit 120-kV, North Truckee-Summit 120-kV and Truckee-Summit 60-kV ties. At approximately 1425:08.300 the 120-kV ties were tripped by out-of-step relays. The 60-kV tie also tripped. At 1425:09.255, the Humboldt-Midpoint 345-kV line relayed at Midpoint on instability. An additional 55 MW of transmission dependent load was tripped as part of Sierra's remedial action scheme for loss of the Humboldt-Midpoint line.



On loss of the Humboldt-Midpoint line, the Idaho (Island 4) and northern Nevada (Island 5) islands were formed, leaving the Western Interconnection separated into four islands. After islanding, the northern Nevada island was in an over-frequency condition.

At this point, the Rocky Mountain area was still connected with Arizona/California. The entire southern island was approximately 5000 MW deficient in generating resources. The frequency in this island declined to 59.2 Hz at 1425:100. Underfrequency load shedding of approximately 3000 MW occurred in Utah and Colorado. The resultant excess generation in the Rocky Mountain area tried to flow to Arizona/California where they were still deficient. This caused an out-of-step separation across the TOT 2 Path, (Utah/Colorado, Arizona/New Mexico/Nevada interface). This out-of-step swing (at 1425:11) tripped the Waterflow-Hesperus, Pinto-Four Corners, and Red Butte-Harry Allen 345-kV lines, the Lost Canyon-Curecanti and Sigurd-Glen Canyon 230-kV lines, and the Durango-Glade Tap 115-kV line. Sierra Pacific's 55-kV ties to Southern California Edison Company tripped on low voltage due to the out-of-step swing.



The foregoing actions completed the formation of two more islands — the Utah, Colorado, Wyoming, western South Dakota, western Nebraska island (Island 3), and the California, Baja California, southern Nevada, Arizona, New Mexico, El Paso island (Island 1). At this time formation of all five islands was complete.

<u>Summary of Load Loss within Islands</u>

Island 1

Within Island 1, frequency dropped to 59.1 Hz and underfrequency load shedding occurred with Pacific Gas and Electric Company shedding 2400 MW and Southern California Edison shedding 505 MW. Approximately 4,484 MW were shed affecting approximately 1,183,000 customers. Over 90% of the load was restored within 30 minutes and all load was restored within 2½ hours.

Island 2

Another major island consisted of Washington, Oregon, Montana, British Columbia, and Alberta. About 3,900 MW of generation was automatically tripped in this island by overfrequency relays and by the remedial action scheme that monitors the California-Oregon Intertie. Impact on customers was minimal. An estimated 7452 customers (100 MW) were interrupted over a period ranging from minutes to about one hour. About 7 MW of firm BPA load and 3 MW of an industrial customer's load at COPD was lost on low voltage.

Island 3

Island 3 included Utah, Colorado, Wyoming, western Nebraska and western South Dakota. While islanded with Arizona/California, the frequency dropped to 59.2 Hz and as much as 3,348 MW of load was shed, mostly due to underfrequency, along with overvoltage and manual load shedding. After separating from Arizona/California, the frequency went as high as 61.1 Hz and 2,000 MW of generation was tripped in the island for various reasons. The frequency remained high for about six minutes. With load restoration, generation ramping down, and 2000 MW of generation tripping , the frequency again fell as low as 59.3 Hz. This resulted in underfrequency load shedding followed by additional load being manually shed in the island in an effort to restore proper frequency. The underfrequency load shedding operated as designed and frequency recovered to 59.35. At this time, various generator underfrequency protection schemes began timing (59.4 Hz for 180 seconds). The frequency remained at 59.35 Hz for 120 seconds and leveled off at 59.5 Hz. After islanding occurred, the island frequency condition was exacerbated by ramping the Stegall (11 minutes after islanding) and Virginia Smith DC (22 minutes after islanding) ties in the wrong direction for one to three minutes. About 100 MW was being exported to MAPP instead of being imported from MAPP.

Island 4
The fourth island was formed in southern Idaho and a small part of eastern Oregon where virtually all customer load and generation was interrupted. A small portion of Bonneville Power load at LaGrande remained connected to six western Idaho generators that remained on line at Hells Canyon, Oxbow and Brownlee. A portion of PacifiCorp's load in southeastern Idaho remained in this island and lost service. About 3,368 MW of load (425,000 customers) was interrupted. Idaho Power Company lost all load in Idaho and radial load located in northern Nevada as well as a small part of eastern Oregon.

BPA customer load in the LaGrande, Baker, John Day, and Burns was in a sub-island carried by IPC's Hells Canyon complex generation. Following the Roundup-La Grande and Mill Creek-Antelope line trips, 40 MW of load was dropped due to extremely low voltage at LaGrande. One customer lost 14 distribution arrestors in the LaGrande and Baker areas due to high voltage. This same customer tripped it's West John Day and Burns (Hines) loads via overvoltage relays. The Baker load was tripped at 1455 and stayed out till 1647.

Island 5
A fifth island was formed in northern Nevada at 1425:09.255. SPP lost a total of 550 MW of load before restoration could be completed. Of this, about 418 MW was lost during the transient frequency and voltage dips which coincided with a power surge going through northern Nevada toward southern Idaho. The 418 MW load loss occurred as the first island began to separate from the rest of the WSCC at 1425:07.395. Of the 418 MW, 250 MW was comprised of underfrequency load shedding; the remaining 168 MW was uncontrolled loss of voltage sensitive loads. Voltage sensitive loads consist primarily of motor load which is lost when motor contactors drop out during severe low voltage. While the loss of 168 MW of customer load was scattered throughout northern Nevada, 103 MW was lost in the system north of Valmy. At 1425:09.255, the Humboldt-Midpoint 345-kV tie tripped as southern Idaho had lost stability with northern Nevada. This initiated a remedial action scheme that successfully tripped 55 MW of transmission dependent load. Frequency jumped to 60.75 Hz in northern Nevada once islanded. At 1427:11, the 120-kV system south of Anaconda Moly blacked out 17 MW of load due to overvoltage. At 1430:26, the Austin-Frontier 230-kV line opened at the Austin end on over voltage, sending a transfer trip signal to Gonder which opened the Gonder end of the Gonder-Machecek 230-kV line. This blacked out 20 MW of load off the 230-kV system between Fort Churchill and Gonder. Gonder loads were still being fed via Utah. An additional 40 MW was lost on underfrequency load shedding during the restoration sequence.

Restoration

Island 1

Restoration of the transmission system in Island 1 began at 1454 hours when the Malin-Round Mountain #1 500-kV line breakers at Round Mountain were closed to parallel Island 1 with Island 2. At 1458 hours, the WSCC was notified that Malin-Round Mountain #1 and #2 500-kV lines were in service and that the California-Oregon Intertie was available for 2500 MW north to south.

At 1505 hours, the Captain Jack-Olinda 500-kV line was returned to service. Between 1543 and 1545 hours, the Table Mountain-Vaca Dixon 500-kV and Table Mountain-Tesla 500-kV line series capacitors at Table Mountain were fully restored to service.

At 1549 hours, Colorado ties were established with Arizona/New Mexico at Hesperus and Lost Canyon.

The Arizona to Utah tie was established when the Four Corners-Pinto 345-kV line was energized at 1603 hours.

Over 90% of firm load in Island 1 was restored by 1500 hours, and all load was restored by 1700 hours.

At 1630 hours, the California-Oregon Intertie was available for 4000 MW north to south.

Southern California Edison and Sierra Pacific Power paralleled at Silver Peak at 0003 hours on July 3, 1996.

Island 2

PacifiCorp's 23 MW load in Alturas (northern California) and Enterprise (eastern Oregon) was lost only momentarily, and restored in less than a minute. The 35 MW load lost around Malin was restored within three minutes, thus completing the restoration of service to 7436 customers. The remaining one industrial customer had a 40 MW on-site generator, and the delay in restoring service occurred due to coordination of some switching related problems.

The restoration of the transmission system in Island 2 began when the Grizzly-Ponderosa-Summer Lake line was closed for test from Grizzly at 1428 and tripped due to switch into fault logic.

BPA's Warner 115-kV low-side PCB closed at 1429:01. Just prior to BPA closing the Harney 115-kV PCB on the Redmond line the Harney bus voltage was 144-kV. At 1429:40.8 when closed, the initial flow was 70 MW to Redmond. Again the position tripped at 1429:41.0 on a power swing out. The voltage dropped to 5-kV line-to-line and after rising about the loss of potential setpoint, tripped via zone 1. The Harney 115-kV Shunt Reactor was closed at 1433 and the 230-kV Anaconda shunt caps switched off automatically at 1442

At 1448 Malin PCB 4064 was closed connecting the Round Mountain No. 1 line to Captain Jack (and Grizzly/Meridian). This tied Island 1 and 2 together. At 1455 the second Malin-Round Mountain PCB was closed, energizing the Malin south bus and PACW 500/230-kV transformer. At 1456, Malin PCB 4582 was closed tying the Round Mountain No. 2 line to the South Bus. At 1457 the second Malin-Round Mountain No. 2 PCB 4072 was closed tying to the Grizzly No. 2 line.

After isolating failed the Captain Jack PCB 4980, the Olinda line PCB 4977 was closed at 1504 tying Olinda to the North Bus (Grizzly/Meridian).

At 1508, Malin PCB 4019 was closed, energizing the Captain Jack No. 2 line. At 1509 the Captain Jack PCBs 4986 and 4996 were closed, thus restoring the line. At this point, Captain Jack had all lines in service with the failed PCB 4980 isolated. At Malin, the 500-kV North Bus and the Summer Lake lines were still out of service.

At 1513 all Fort Rock Series caps were bypassed for normal operation.

At 1530, the Malin 500-kV North Bus was energized by closing PCB 4066 and PCB 4070. At Malin, shunt capacitor group No. 4 was still out due to the failed PCB 4184.

At 1528, the Bell PCB A374 was opened to restore the sectionalized Boundary No. 1 line to normal service. The line had faulted earlier in the day at 1057. The PCB was closed at 1533. At 1458, BPA closed Round Up PCB A564 and at 1600 closed the LaGrande 230-kV PCB A-272 restoring the Round Up-LaGrande 230-kV line to service. This completed the restoration of the 230-kV ties between Idaho and Northwest.

At 1600 the MOD 4616 at Ponderosa on the Grizzly line was opened. At 1602, after taking reactor 3 out of service, Grizzly PCB 5025 was closed, energizing to Ponderosa. The PCB was re-opened at 1603. The MOD line disconnect was closed at 1612 and Grizzly PCB was closed at 1620 energizing to Ponderosa. (The other line PCB 5028 was closed at 1653 and the Sand Springs series capacitors were inserted at 1654). The Ponderosa Bk MOD 4615 500/230-kV transformer was closed at 1528 and both low side PCBs A398 and A394 were closed at 1529 restoring the station to normal and making parallel to PacifiCorp's western system.

At 1604 the Malin Reactor No.1 was switched off. At 1605 the PacifiCorp's 230-kV PCB 1L1 and 1L12 were closed, restoring the 500/230-kV transformer low-side (and ties to Klamath Falls and Warner). This brought the Warner 115-kV low-side voltage back into normal range at 120-kV (It had alarmed high 123-kV at 1601:18).

Between 1606 and 1607, reactors at Lower Monumental, Dworshak, and Malin (Grizzly 2) were switched off and at 1622, the Malin PCB 4576 was closed to test the Summer Lake line but tripped due to a bad arrestor.

Island 3

Restoration began with closing in the Red Butte-Harry Allen 345-kV line. At 1431:31, the Harry Allen 345-kV breaker (HA4542) was closed, re-establishing the tie between Utah and Nevada Power and tying Island 3 with Island 1. At 1432:17, the Westside and Decatur ends of the Harry Allen-Westside-Decatur 230-kV line (underlying 230-kV system out of Harry Allen) tripped on zone 3 impedance relay due to overload, separating the Harry Allen substation from the Nevada Power system. Not realizing that the WSCC interconnection had divided into islands, the Nevada Power dispatcher again closed the Decatur and Westside 230-kV breakers at 1443:45, reconnecting Islands 1 and 3 out of synchronism. This resulted in the instantaneous (approximately 3 cycle) tripping of the Harry Allen 345-kV bus backup impedance relay on zone 1, and the 85BU lockout relay which locked out the Harry Allen 345 and 230 kV breakers. A troubleman had to be dispatched to the station in order to clear the lockout.

Auxiliary power was restored to the Jim Bridger plant in Wyoming for startup at 1434 by closing the 345/230-kV transformer at the plant. At 1435, (11 minutes into the disturbance), the Stegall AC-DC-AC tie was re-energized. The tie operator began ramping an intended schedule of 110 MW into WSCC from MAPP (Mid-Area Power Pool), but due to the pre-disturbance configuration of the tie, the schedule was ramping in the wrong direction. The error was discovered in three minutes and the ramp reversed to import the power from MAPP.

At 1437, (thirteen minutes into the disturbance), the tie operator of the Virginia Smith AC-DC-AC tie (VSCS) de-energized the tie to cancel a pre-disturbance export of 110 MW from WSCC to the MAPP area. At 1447, (twenty two minutes into the disturbance), the VSCS began ramping an intended additional 110 MW import from MAPP to WSCC, however, the pre-disturbance configuration of the tie caused this tie to export. At 1448, the VSCS ramp was reversed to import the power.

At 1434, Island 3 still had low frequency. PSC manually shed 384 MW and PacifiCorp's Utah operators dropped about 135 MW of load at 1450. Frequency was restored by about 1500.

At 1451 and 1452, Yellowtail hydro units #2 and #3 synchronized on-line.

The three Grace-Treasureton 138-kV lines were restored between 1504 and 1507.

Rawhide tripped at 1515 for high combustibles.

At 1515, operators closed the Big Grassy-Dillon 161-kV line and the Big Grassy-Jefferson 161-kV line which established a tie with Montana Power, but also picked up all of Idaho and immediately tripped the 161-kV line at Dillon. Breakers were then opened in the Goshen/Antelope area to isolate from Idaho Power. At 1522, the Mill Creek-Antelope 230-kV line was restored, energizing the Antelope/Goshen area.

The tie at Yellowtail between PacifiCorp and WAPA was closed at 1534. The Yellowtail to Crossover 230-kV line was restored at 1539. At 1539, Pawnee synchronized on-line (full output was available by 1930). The Yellowtail-Billings ties were closed at 1540 and 1542, establishing a tie from Island 3 to Island 2. At 1543 the Thermopolis-O.Basin 230-kV line was restored.

At 1544, WAPA load at Badwater was restored. At 1545 the WAPA Thermopolis to Lovell 115-kV line was re-energized. At 1548, Hesperus to Waterflow 345-kV was re-energized and Lost Canyon to Curecanti 230 kV was re-energized at 1549.

Yellowtail hydro units #4 and #1 were brought back on-line at 1550 and 1554.

The Pinto-Four Corners 345-kV line was connected at 1600. The Red Butte-Harry Allen 345-kV line was restored at 1612. The Goshen-Grace 161-kV line was restored at 1621.

Bridger unit 2 and unit 1 breakers were closed at 1626 and 1638 respectively (tied to the 230-kV system). At 1631, Laramie River Station unit #2 (LRS2) synchronized on-line. Full output was available by 2000.

At 1642 the Ben Lomond-Borah 345-kV line was closed, establishing a tie to Idaho Power.

The Bridger-Borah 345-kV line was restored at 1656. The Goshen-Bridger 345-kV line was restored at 1701 and a Goshen 345/161-kV transformer was closed at 1704.

The tie between Jefferson, Big Grassy, and Montana Power was restored at 1707.

The Bridger #1 unit tripped again at 1719.

At 1730 the WAPA-Thermopolis to PACE-Thermopolis115-kV interconnection was restored. This two hour delay from the initial attempt was caused by failure of the synchronizer due to jumpers left in place.

From 1733 to 1738, ties with Idaho Power were restored: the Antelope-Brady and Treasureton-Brady 230-kV lines, the American Falls-Malad 138-kV line, and the Goshen-Kinport 345-kV line. The Bridger-Kinport 345-kV line was closed at 1741.

At 1751 the Sigurd-Glen Canyon 230-kV line was finally closed after many unsuccessful attempts. A faulty relay was found at Sigurd substation and was repaired. The Sigurd phase shifting transformer and Pinto phase shifting transformers were put back into service at 1755 and 1759 respectively. The Goshen-Blackfoot 161-kV tie to Idaho Power was restored at 1757. Bridger unit 1 was back on line at 1823.

By 1900 all firm load in the island had been restored. Interruptible load was fully restored by 2000.

Island 4

Restoration of Island 4 began from near black start conditions. Several units at Brownlee and Oxbow hydro plants remained in service during the disturbance and were feeding a small amount of load at LaGrande, Oregon. At 1459, the Boise Bench-Brownlee #3 230-kV line was energized, thus providing power to the Boise area. At this point, system dispatchers began restoring load in the Boise area. Load restoration was coordinated with generation increase from Brownlee, Oxbow and Hells Canyon. Once a solid generation/load base was established, dispatchers began restoring load to the west and east of Boise. At 1539 the Boise Bench-Brownlee #1 230-kV line was energized which strengthened ties between load and generation. At approximately 1518, 230-kV ties to Washington and Oregon were reestablished when the Hells Canyon-Walla Walla 230-kV and Oxbow-Lolo 230-kV lines were reenergized. Between 1528 and 1541, Brownlee units 1,2 and 4 as well as Hells Canyon units 1,2 and 3 were brought on line.

Bridger Units 1 and 2 were brought on-line between 1626 and 1637, providing generation on the east side of the island. At 1637, the Boise Bench-Brownlee #2 230-kV line was energized, allowing more power to flow into Boise. The Borah-Ben Lomond 345-kV line was energized at 1639, thus establishing a tie from southeastern Idaho to northern Utah.

System dispatchers then began to build the backbone transmission system tying the western Idaho to Eastern Idaho. This was accomplished by energizing the Midpoint-Borah #1 345-kV line at 1647, the Bridger-Borah 345-kV line at 1656, and the Boise Bench-Midpoint #2 230-kV line at 1658.

The Idaho to Sierra Pacific (northern Nevada) tie was reestablished at 1659 when the Midpoint-Humboldt 345-kV line was energized. Dispatchers continued to build the transmission infrastructure of the Idaho Power system in concert with restoring load. At 1700, the Bridger-Goshen 345-kV line was energized.

A Montana to Idaho tie was established at 1733 when the Brady-Antelope 230-kV line was energized. Ties between eastern Idaho and Utah were strengthened at 1735 with the energization of the Brady-Treasureton 230-kV line and American Falls-Wheelon 138-kV line at 1736. The Bridger West transmission system was fully restored at 1741 when the Bridger-Kinport 345-kV line was energized. Idaho Power's ties to PacifiCorp's eastern Idaho load were reestablished when the Kinport-Goshen 345-kV and Blackfoot-Goshen 161-kV lines were energized at 1743 and 1756, respectively.

The Midpoint-Summer Lake 500-kV line was restored at 1753 which reestablished the tie between southern Oregon and Idaho.

At this point, all major tie lines between Idaho and its neighbors where reestablished. Restoration internal to Idaho continued until 2045 when service was restored to an interrruptible customer.

Island 5

At 1430:10, system dispatchers started the restoration of underfrequency load shed circuits, beginning with Stateline, Northwest and Winnemucca Substations.

At 1430:26, the Austin-Frontier 230-kV line opened at the Austin end on over voltage and sent a trip to open the Gonder-Machacek 230-kV line at Gonder. This blacked out the 230-kV system between Fort Churchill and Gonder, involving 20 MW of load. Gonder loads were still being fed via Utah.

While in an island, the restoration of loads shed on underfrequency continued. Loads were restored while generation was ramped. This was rather tricky, as frequency bounced around with the generation load imbalances. Within 15 minutes of islanding, the high frequency island had dropped below 60 Hz. Over the next couple of hours, frequency was manually controlled within a wide range while remaining in an island.

At 1446:17, the frequency drifted below the underfrequency setpoint of the non-utility Brady's geothermal unit. The unit tripped 15 MW of generation causing the frequency to drop to about 59.25 Hz. This resulted in the pick up of steps #1 & #11 of underfrequency load shedding. The Winnemucca circuit that had already been restored was shed again. In addition, 40 MW at Glendale was shed on step #11 (step #11 also trips at 59.3 Hz, but with a long time delay).

In all, 550 MW of load was lost (43% of Sierra's control area), of which 382 MW was interrupted due to underfrequency load shedding and overvoltage transfer tripping. Some of the remaining 168 MW of uncontrolled load loss, (lost load due to voltage dip), was out for an extended time. Larger customers were encouraged to keep non-critical loads off line until the situation stabilized.

At 1528:18, the Ft Churchill-Austin 230-kV line was closed, restoring the small town of Austin. At 1531:11, the Austin-Frontier 230-kV line was closed, restoring power to the blacked out 230-kV region. At 1601:44, the remaining blacked out region south (i.e. the 120/60-kV south of Millers) was restored. To do this, the 120-kV transmission at Millers Substation was rerouted to provide an alternate source of power to the town of Tonopah and surrounding area (fed via the Ft Churchill 120-kV).

At 1604:36, Stampede, a small hydro, tripped. At 1604:44, some of the Spanish Springs and Winnemucca Subs underfrequency load shedding circuits picked up as frequency had drifted too low during load pick up (the trip of Stampede hydro may have tipped the scale).

By 1613:15, most of Sierra's own customers had been restored. All generation within the island was fully loaded. No additional reserves were available. Still in an island, Sierra had recovered 88% of its control area load primarily using internal generation.

At 1617:32, there was an attempt to parallel the northern Nevada island with southern Idaho. The attempt to close the Humboldt end of the Humboldt-Midpoint 345-kV line failed due to abnormally high voltage.

Sierra Pacific Power restored its AGC, putting it on flat frequency control. At 1639:14, northern Nevada successfully paralleled to the west with California. The Cal Sub autosynchronizer was used to help make the tie.

At 1659:26, northern Nevada and southern Idaho were paralleled by closing the Midpoint-Valmy 345-kV line. At 1742:26, the Gonder-Machacek 230-kV line was closed, tying northern Nevada to the east with Utah (i.e., PACE and LDWP).

Once the Humboldt-Midpoint tie was closed and schedules established, the transmission dependent loads were promptly restored in northern Nevada. That is, at 1806:21, the Harney loads and at 1811:36, the Gold Quarry loads were picked up. At 1811, northern Nevada's loads and transmission were mostly restored.

The Silver Peak-Control 55-kV lines were restored at 0103:35 on July 3, 1996, thus completing the restoration of the SPP transmission system.

July 3 Disturbance

The following day, July 3, 1996, at 2:03 p.m. a similar chain of events began. The Jim Bridger-Kinport 345-kV line again flashed to the tree and was automatically disconnected by protective devices, clearing the short circuit. At nearly the same time, the Jim Bridger-Goshen 345-kV line was automatically disconnected due to misoperation of the same protective device that misoperated on July 2. The outage of two of the three 345-kV lines west of the Jim Bridger power plant triggered the Bridger remedial action scheme, automatically disconnecting two of the four Jim Bridger units. Operating conditions on July 3 were different from those on July 2. Schedule limits on the California-Oregon Intertie were reduced to 4,000 MW north to south pending the results of technical studies being conducted to analyze the prevailing operating conditions. Interchange schedules through Idaho from the Northwest were reduced and generation patterns in the Northwest were changed. Brownlee No. 5 generating unit in western Idaho was returned to service following a forced outage and provided additional voltage support.

Following the loss of the Bridger lines and generation, the Brownlee generating plant in western Idaho increased to maximum reactive output limits and was providing critical voltage support for the Boise area. Voltage in the Boise area stabilized at 224-kV. The Brownlee plant operators received maximum excitation limit alarms and became concerned about the amount of reactive power being supplied by their units. As a precautionary measure to avoid possible unit trips of critical generation, the operators placed the voltage regulators in "manual" operation, and reduced the voltage set point. Although this action did relieve stress on the generating units, it was undesirable from an interconnected system standpoint in that it reduced reactive support to the Boise area which contributed to the need for manual load shedding to arrest declining voltage. This action induced a steady voltage decline to 205-kV over a three-minute period.

At this time, system dispatcher action at the control center shed 600 MW over the next two minutes to arrest voltage decline in Boise. Voltages immediately recovered to 230-kV upon the completion of load shed. It is not clear whether the IPC system operators would have had to resort to shedding firm load had the Brownlee plant continued to contribute full reactive support.

All customer load was restored within 60 minutes, except an interruptible industrial customer that was restricted to half load until the Jim Bridger generation was restored at about 5:30 p.m.

V. SEQUENCE OF EVENTS

The sequence of events listing is available in electronic form as an Excel 5.0 spreadsheet. If you would like a copy, please call the WSCC office (801-582-0353) and request it be e-mailed or faxed to you.

VI. DISTURBANCE EVALUATION CHECKLIST

DISTURBANCE CATEGORY	DEFINITION	CONTRIBUTING FACTOR IN CAUSING THE DISTURBANCE, INCREASING ITS SEVERITY, OR HINDERING RESTORATION? (YES OR NO)	EXPLANATORY COMMENTS
1. Power System Facilities	The existence of sufficient physical facilities to provide a reliable bulk power supply system.	Yes	Did not have sufficient reactive capability for the operating conditions in the Northwest and Idaho
2. Relaying Systems	Detection of bulk power supply parameters that are outside normal operating limits and activation of protection devices to prevent or limit damage to the system.	Yes	Misoperation of the protection systems on the Jim Bridger-Goshen 345-kV line contributed to both disturbances. The LaGrande-Round Up relay misoperation contributed to the July 2 disturbance
3. System Monitoring, Operating, Control, and Communications Facilities	Ability of dispatch and control facilities to monitor and control operation of the bulk power supply system. Adequacy of communication facilities to provide information within and between control areas.	Yes	Lack of a security monitoring process, limits not known and well understood,
4. Operating Personnel Performance	Ability of system personnel to react properly to unanticipated circumstances which require prompt and decisive action.	Yes	Operators at Brownlee Plant prevented their units from providing full reactive support as the voltage was collapsing on July 3. TSGT and WALM operators ramped the AC-DC-AC links to MAPP in the wrong direction initially.
5. Operational Planning	Study of near term (daily, weekly, seasonal) operating conditions. Application of results to system operation.	Yes	Failure to adequately study the effects of extremely high hydro generation levels throughout the Northwest, heavy north to south transfers on the COI, record loads in Idaho and Utah and moderate west to east loading through Idaho combined with double line outages.
6. System Reserve and Generation Response	Ability of generation or load management equipment to maintain or restore system frequency and tie line flows to acceptable levels following	Yes	Reactive margin problems, generator response

DISTURBANCE CATEGORY	DEFINITION	CONTRIBUTING FACTOR IN CAUSING THE DISTURBANCE, INCREASING ITS SEVERITY, OR HINDERING RESTORATION? (YES OR NO)	EXPLANATORY COMMENTS
	system disturbance.		
7. Preventive Maintenance	A program of routine inspections and tests to detect and correct potential equipment failures.	Yes	Tree trimming deficiencies, relay maintenance problems
8. Load Relief	The intentional disconnection of customer load in a planned and systematic manner to restore the balance between available power supply and demand.	Yes	There was no plan for load shedding to prevent voltage collapse in the IPC system. Studies will verify whether undervoltage load shedding would have been effective for the July 2 outage.
9. Restoration	Orderly and effective procedures to quickly reestablish customer service and return the bulk power supply system to a reliable condition.	Yes	Poor communications among control centers delayed restoration of ties and generation changes needed.
10. Special Protection Systems	Use of relays to initiate controlled separation and generator tripping to prevent a widespread blackout.	Yes	NE/SE separation scheme out of service (by mutual agreement of WSCC members)
11. System Planning	Comprehensive planning work utilizing appropriate planning criteria to provide a reliable bulk power supply system.	Yes	Insufficient studies were conducted to determine the transfer limits of the system under conditions prevailing at the time of the disturbance.
12. Other	Any other factor not listed above which was significant in causing the disturbance, making the disturbance more severe or adversely affecting		

DISTURBANCE CATEGORY	DEFINITION	CONTRIBUTING FACTOR IN CAUSING THE DISTURBANCE, INCREASING ITS SEVERITY, OR HINDERING RESTORATION? (YES OR NO)	EXPLANATORY COMMENTS
	restoration.		

VII. EXHIBITS

1. Islands Formed and Event Sequence Map
   The Islands Formed and Event Sequence Map are available electronically as Corel 5.0 files. If you would like a copy, please call the WSCC office (801-582-0353) and request that they be e-mailed to you.

2. Interchange Diagrams
   The Interchange Diagrams are available in electronic form as Excel 5.0 spreadsheets. If you would like a copy, please call the WSCC office (801-582-0353) and request that they be e-mailed to you.

3. Voltage, Power, and Reactive Plots
   These Plots are available only in hard copy.

4. Flows Versus Ratings of Key Transmission Paths
   This table is available as an EXCEL file. If you would like a copy, please call the WSCC office (801-582-0353) and request that they be e-mailed to you.

5. Los Angeles Area Frequency

6. Diagram Showing System Voltages Prior to Outage

Exhibits available in the printed disturbance report are not available in electronic form.

WESTERN SYSTEMS COORDINATING COUNCIL

DISTURBANCE REPORT

For the Power System Outage that Occurred on the Western Interconnection

August 10, 1996 1548 PAST

Approved by the WSCC Operations Committee on October 18, 1996

DISTURBANCE REPORT TASK FORCE MEMBERS

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System Identifiers

Throughout the report, organizations are identified using the acronyms listed below.

APS – Arizona Public Service Company
BPA – Bonneville Power Administration
BURB - Burbank, City of
BCHA – British Columbia Hydro and Power Authority
CDWR - Department of Water Resources/California
CSU – Colorado Springs Utilities
CFE - Comision Federal de Electricidad
EPE – El Paso Electric Company
EWEB – Eugene Water & Electric Board
FARM - Farmington, City of
GLEN - Glendale, City of
IPC – Idaho Power Company
LDWP – Los Angeles Department of Water and Power
MWD – Metropolitan Water District/ Southern
MID – Modesto Irrigation District
MPC – Montana Power Company, The
NEVP – Nevada Power Company
NCPA – Northern California Power Agency
NWPP – Northwest Power Pool
OXGC – Oxbow Geothermal Corporation
PG&E – Pacific Gas and Electric Company
PAC – PacifiCorp
PASA – Pasadena, City of
PEGT – Plains Electric Generation and Transmission Cooperative, Inc.
PGE – Portland General Electric Company
PNM – Public Service Company of New Mexico
COPD – PUD No. 1 of Cowlitz County
DOPD – PUD No. 1 of Douglas County
GCPD – PUD No. 2 of Grant County
SNPD – PUD No. 1 of Snohomish County

PSPL – Puget Sound Power & Light Company
SMUD – Sacramento Municipal Utility District
SRP – Salt River Project
SDGE – San Diego Gas & Electric Company
SCL – Seattle Department of Lighting (Seattle City Light)
SPP – Sierra Pacific Power Company
SCE – Southern California Edison Company
TCL – Tacoma Department of Public Utilities (Tacoma City Light)
TNP - Texas-New Mexico Power Company
TAUC – TransAlta Utilities Corporation
TSGT – Tri-State Generation & Transmission Association, Inc.
TEP – Tucson Electric Power Company
TID – Turlock Irrigation District
USBR – U.S. Department of Interior Bureau of Reclamation
- USDO – (Denver Office)
- USGP – (Great Plains)
- USLC – (Lower Colorado)
- USMP – (Mid-Pacific)
- USPN – (Pacific Northwest)
- USUC – (Upper Colorado)

VERN – Vernon, City of
WWPC – Washington Water Power Company
WAPA – Western Area Power Administration
- WAHQ – (Golden, Colorado)
- WALC – (Phoenix, Arizona)
- WALM – (Loveland, Colorado)
- WAMP – (Sacramento, California)
- WAUC – (Salt Lake City, Utah)
- WAUM – (Billings, Montana)

I. SUMMARY AND INTRODUCTION

At 1548 PAST on Saturday, August 10, a major system disturbance separated the Western Systems Coordinating Council (WSCC) system into four islands, interrupting service to 7.5 million customers for periods ranging from several minutes to about nine hours. This disturbance effectively began with the loss of the Keeler-Allston 500-kV line in the Portland area, due to inadequate right-of-way maintenance, which overloaded parallel lines and depressed transmission voltages. These conditions led to subsequent tripping of additional lines and McNary generating units, triggering increasing oscillations that eventually caused protective devices to trip the three 500-kV California-Oregon Intertie (COI) lines and other major lines.

In addition to interrupting service to a large number of customers, this severe disturbance tripped fifteen large thermal and nuclear units in California and the Southwest, delaying load restoration. A few large units did not return to service for several days, requiring operators to purchase emergency power to serve the high, hot-weather loads experienced during the following days.

In the wake of this disturbance, a lower limit (3,200 MW) was maintained on the COI to account for operational limits on generation at McNary (exciter problems) and The Dalles (fish protection). To avoid implementing an emergency operating plan in California which, under a worst case scenario, could have necessitated rotating blackouts, the COI limit was increased to 3,600 MW from August 12 to August 14. This was made possible, on an emergency basis, by temporarily reducing Endangered Species Act (ESA) compliance spills and increasing generation output at The Dalles.

Several factors contributed to the occurrence and severity of this disturbance.

1. HIGH NORTHWEST TRANSMISSION LOADING

   The 500-kV and underlying interstate transmission system from Canada south through Washington and Oregon to California was heavily loaded due to:

   - Relatively high loads, caused by hot weather throughout much of the WSCC region.

   - Excellent hydroelectric conditions in Canada and the Northwest, leading to high power transfers (including large economy transfers) from Canada into the Northwest and from the Northwest to California. System conditions in the Northwest were similar to the conditions prior to the July 2, 1996, disturbance, except power was flowing into the Northwest from Idaho. This allowed exports to California on the COI of up to 4,750 MW, as determined by operating nomogram limits developed by BPA, PG&E, IPC, and PAC following the July 2 disturbance.

- During these periods of high transmission loading, BPA operators had previously noticed small changes in power flows causing large changes in voltage, indicating voltage support problems in the Northwest during stressed operating conditions.

2. EQUIPMENT OUT OF SERVICE

- In the hours before the disturbance, three lightly loaded 500-kV lines (Big Eddy-Ostrander, John Day-Marion, and Marion-Lane) in the Portland area were forced out of service. These 500-kV lines were providing reactive power support for the transmission system. Two of the outages were caused by flashovers to trees resulting from inadequate right-of-way maintenance, and one outage resulted from a circuit breaker being out of service.

- The Allston-Rainier 115-kV line was out of service due to degraded capability of line hardware. The Longview-Lexington 115-kV line was out of service for fiber-optic cable installation. These outages contributed to the system stress following the loss of the Keeler-Allston 500-kV line.

- A 500-kV circuit breaker at Marion, a 500-kV circuit breaker at Keeler, and the 500/230-kV transformer at Keeler were out of service for modification. The Static VAR Compensator (SVC) at Keeler was reduced in its ability to support the 500-kV system voltage due to the transformer outage (the SVC is tied to the 230-kV side). Since Northwest loads are historically lower in the summer than in the winter, BPA performs most system maintenance during the summer.

3. TRIGGERING EVENTS

- At 1542:37 PAST, the heavily loaded Keeler-Allston 500-kV line sagged too close to a tree and flashed over, additionally forcing the Pearl-Keeler 500-kV line out of service due to the 500/230-kV transformer outage and breaker replacement work at Keeler. These outages overloaded the parallel 230-kV and 115-kV lines into the Portland area and depressed the 500-kV voltage at Hanford from 527 to 506 kV. The reactive power output from McNary increased to its maximum sustainable level to support the voltage, and held this level for nearly five minutes.

- Approximately five minutes later, (about 1547:29 PAST), the St. Johns-Merwin 115-kV line tripped due to a zone 1 KD relay malfunction, contributing to the loading of other lines parallel to the Keeler-Allston 500-kV line. (The exact time of this event is not known.)

- At 1547:36, the overloaded Ross-Lexington 230-kV line sagged too close to a tree and flashed over, resulting in loss of 207 MW of Swift generation, thus further depressing system voltage and further increasing the demand for reactive power output from McNary generating units, already at their maximum sustainable level. This outage also contributed to loading on the lines parallel to the Keeler-Allston 500-kV line.

- At 1547:37, units at McNary began tripping (due to excitation equipment problems), and increasing power and voltage oscillations began. These oscillations increased in magnitude for approximately 70 seconds, until the three 500-kV COI lines relayed due to low voltage (less than 315 kV on the Malin 500-kV bus) at 1548:52. These oscillations were a major factor leading to the separation of COI and subsequent islanding of the WSCC system.

- Some of the power that had been flowing to northern California on the COI surged east then south through Idaho, Utah, Colorado, Arizona, New Mexico, Nevada and southern California. Numerous transmission lines in this path subsequently tripped due to out-of-step conditions and low voltage. Although several lines between Arizona and southern California tripped, the two areas remained tied together through remaining lines.

4. KEY FACTORS

- BPA's right-of-way maintenance was inadequate. Consequently, BPA's failure to trim trees and remove identified danger trees caused flashovers on and the loss of several 500-kV transmission lines, the last of which led to overloads and cascading outages throughout the Western Interconnection.

- BPA operators were operating the system in a condition in which a single contingency outage (the Keeler-Allston 500-kV line) would overload parallel transmission lines. They were aware that on July 13, the Pearl-Keeler 500-kV line sagged too close to a tree, flashed over and tripped. This forced open the Keeler-Allston 500-kV line at Keeler due to a breaker outage. The outages loaded the parallel Longview-Allston No. 4 115-kV line to 109 percent. Additionally, a jumper on the parallel Allston-St. Helens 115-kV line burned open within two minutes due to failure of conductor hardware that had degraded. It was not loaded above its thermal rating. The two Allston-Trojan 230-kV lines and the Ross-Lexington 230-kV line loaded to their thermal limits. Loading on other lines also increased substantially. While this incident did not lead to cascading outages, it should have served as a warning prior to the August 10 outage and led to further technical analysis.

  BPA operators were unknowingly operating the system in a condition in which the Keeler-Allston 500-kV line outage would trigger subsequent cascading outages because adequate operating studies had not been conducted. Operating in a condition where cascading outages could occur is a violation of the WSCC Minimum Operating Reliability Criteria.

- In the hour and a half prior to the disturbance, BPA's Big Eddy-Ostrander, John Day-Marion and Marion-Lane 500-kV lines were forced out of service. While none of these lines were individually judged to be crucial by BPA dispatchers, the cumulative impact resulted in a weaker system. BPA did not widely communicate these outages to other WSCC members nor did they reduce loadings on lines or adjust local generation as precautionary measures to protect against the weakened state of the system.

BPA notified PGE of maintenance outages in effect, but did not notify other WSCC members. BPA did not widely communicate the forced line outages to other WSCC members, precluding them from making system adjustments had they perceived a need to take such action. BPA did not consider these to be key facility outages for reporting purposes.

- All the units at McNary tripped due to exciter protection as units responded to reduced voltage after the Keeler-Allston 500-kV and subsequent line trips. Even though the loss of McNary units (of ten units operating, three tripped immediately prior to COI separation and two tripped after separation) during the July 2 disturbance had demonstrated problems with the excitation systems on these units, this information had not yet been analyzed and factored into studies performed to develop COI/Midpoint-Summer Lake and other operating limits after July 2. Additionally, some other area generators did not respond to support voltage to the extent modeled in studies used by WSCC utilities.

- The Dalles had only five of 22 generating units operating, generating a total of 320 MW, due to spill requirements imposed to protect salmon smolts migrating downstream, significantly diminishing the voltage support available for the transmission system. The effect of this known operating constraint had not been factored into system studies.

- Growing system oscillations resulted in increasing voltage and power swings on the COI, leading to COI instability and separations. The growing oscillations may be attributed to an increased electrical angle between northwest generation and the COI due to:

  - weakening of the transmission system (loss of Keeler-Allston 500-kV, Ross-Lexington 230-kV and other, lower voltage lines)

  - a shift of generation to Grand Coulee and Chief Joseph following tripping of the McNary units

  - reduced reactive support to the COI resulting from loss of McNary units and nonparticipation of Coyote Springs, and Hermiston

In addition, the response of the PDCI to system voltage swings may have contributed to growing oscillations.

5. WIDESPREAD LOSS OF GENERATION AND LOAD.

   - The loss of the COI (which also occurred on July 2) resulted in approximately 28,000 MW of underfrequency load shedding and approximately 20,000 MW of undesired generation loss in the northern California and southern islands in this disturbance.

In summary, the disturbance could have been avoided, in all likelihood, if contingency plans had been adopted to mitigate the effects of the Keeler-Allston 500-kV line outage. Inadequate tree-trimming practices, operating studies, and instructions to dispatchers also played a significant role in this disturbance.

ISLANDS

The disturbance created four electrical islands:

1. Northern California Island (north of Los Angeles extending to the Oregon border)
   - Created by: loss of the COI, Midway-Vincent out-of-step tripping, tripping of the PG&E-SPP ties
   - Load lost: 11,602 MW (388,017 MW-minutes) - due to manual and automatic underfrequency load shedding
   - Generation lost: Over 40 units totaling 7,937 MW due to loss of excitation from low voltage and out-of-step conditions, turbine-generator vibration, antimotoring and line trips
   - Customers affected: 2,892,343
   - Frequency: dipped initially to 58.54 Hz, spiked to 60.7 Hz, dropped again to 58.3 Hz, and returned to normal in two and a half hours

2. Southern Island (southern California; southern Nevada; Arizona; New Mexico; El Paso, Texas and northern Baja California)
   - Created by: out-of-step tripping between Utah/Colorado and Arizona/New Mexico/Nevada and out-of-step tripping between Midway and Vincent and tripping of the SCE-SPP 55-kV ties
   - Load lost: 15,820 MW, (1.98 million MW-minutes) due to automatic and manual underfrequency load shedding
   - Generation lost: Over 90 units totaling 13,497 MW due to loss of excitation, boiler instability, overcurrent, underfrequency, flame failure, overfrequency and line trips
   - Customers affected: 4,195,972
   - Frequency: spiked to 61.3 Hz, dropped to 58.5 Hz, returned to normal in 70 minutes

3. Northern Island (British Columbia, Oregon, Washington, Montana, Wyoming, Idaho, Utah, Northern Nevada, Colorado, western South Dakota, and western Nebraska)
   - Created by: loss of COI, BCHA/TAUC separation, tripping of PG&E-SPP ties, SCE-SPP ties, and Utah/Colorado-Arizona/New Mexico/Nevada ties
   - Load lost: 2,099 MW (95,075 MW-minutes) due to loss of transmission
   - Generation lost: 60 units totaling 5,689 MW, due to activation of the Pacific AC and DC Intertie remedial action schemes, overfrequency, or loss of excitation due to low voltage
   - Customers affected: 209,858
   - Frequency: increased to 60.4 Hz, returned to normal in 17 minutes

4. Alberta Island (Alberta)
   - Created at 1554:36 by: generation in Alberta ramped back due to high frequency, overloading and tripping the BCHA/TAUC interconnection.
   - Load lost: 968 MW (24,888 MW-minutes, due to automatic underfrequency load shedding
   - Generation lost: six units totaling 146 MW due to overfrequency
   - Customers affected: 191,904
   - Frequency: increased to 60.4 Hz, then dropped to 59.0 Hz and returned to normal within six minutes

TOTAL WSCC IMPACTS:
Load lost: 30,489 MW
Generation lost: 27,269 MW
Customers affected: 7.49 million
Load not served: 2.48 million MW-minutes

II. CONCLUSIONS AND RECOMMENDATIONS

All recommendations will require a response to WSCC by the indicated date and denote the party responsible for reporting. The WSCC will track progress on each recommendation. The WSCC Board of Trustees will be responsible for ensuring that all recommendations are implemented in accordance with the schedule. Target completion dates are indicated in parentheses following each recommendation.

1. **Conclusion:** System operation was not in compliance with the WSCC Minimum Operating Reliability Criteria (MORC) prior to the outage of the Keeler-Allston 500-kV line. Outage of the Keeler-Allston 500-kV line precipitated the overloading and tripping of parallel lines, voltage drops, the undesirable tripping of key hydro units, and subsequent increasing oscillations, all of which led to tripping the COI and other major lines, and separating the system into four islands, causing the widespread uncontrolled outage of generation, and interrupting electric service to approximately 7.5 million customers.

   The following are excerpts from the WSCC MORC and the WSCC Reliability Criteria for Transmission System Planning:

"... Member Systems shall establish interarea transfer capability limits for conditions representing the outage of any of the facilities that affect the transfer capability limits."

"The systems or control areas will remain stable upon loss of any one single element without system cascading that could result in the successive loss of additional elements."

"Systems or control areas should immediately take steps to . . . ensure that loss of any subsequent element will not violate the transfer capability limit criteria."

"During an emergency condition, security and reliability of the bulk power system are threatened; therefore, immediate steps must be taken to provide relief . . . Loss of Any Element - The system(s) causing the emergency condition shall take immediate steps to relieve the condition by adjusting generation, changing schedules between control areas, and initiating relief measures including manual or automatic load shedding (if required) to relieve overloading or imminent voltage collapse."

"The Criteria does not permit any uncontrolled loss of generation, load, or uncontrolled separation of transmission facilities."

Recommendation:

a. BPA shall assess why it failed to identify that a Keeler-Allston 500-kV line outage would overload parallel lines, and potentially violate the WSCC MORC. BPA shall immediately implement corrective action as appropriate. BPA's assessment and mitigating actions (e.g., operating procedures, training, studies, etc.) that have been or are being taken shall be submitted to WSCC's Compliance Monitoring and Operating Practices Subcommittee (CMOPS). (December 1996)

b. Northwest Power Pool members shall reassess their operating policies, practices, and procedures to ensure that the Northwest bulk power system is operated in compliance with WSCC and NERC criteria and procedures in light of the August 10 and July 2 disturbances and report to CMOPS. (December 1996)

2. **Conclusion:** The outage of the Keeler-Allston 500-kV line overloaded the four parallel lower voltage lines. PAC's Merwin-St. Johns 115-kV (by relay misoperation) and BPA's Ross-Lexington 230-kV lines subsequently tripped and the remaining two PGE 230-kV lines loaded to 150 percent of their emergency rating. PGE's parallel 230-kV lines were overloaded (for approximately seven minutes) after the loss of the Keeler-Allston 500-kV line. These outages and overloads caused a voltage drop in the Hanford area, in turn causing the McNary generating units to increase their reactive power output — already at the maximum sustainable level.

Recommendation:

a. The WSCC Operations Committee (OC) and Planning Coordination Committee (PCC) shall thoroughly review WSCC's and its members' processes for studying upcoming system operating conditions and implement any changes for WSCC processes and recommend changes for members' processes as needed to ensure that these processes for identifying all critical and unusual operating conditions are adequate, and that credible disturbances are adequately studied prior to encountering them in real-time operating conditions. (March 1997)

b. The WSCC OC shall develop a process for reporting on anticipated operating conditions, critical conditions, and the results of studies conducted to assess these conditions. (March 1997)

c. BPA shall review and report to CMOPS regarding procedures for identifying and accounting for critical operating conditions and implement appropriate corrective measures. (December 1996)

d. WSCC's Security Process Task Force (SPTF) shall pursue implementation of on-line power flow and security analysis, and recommend appropriate actions to increase the monitoring of key system parameters that would allow operators to identify potential problem outages and take corrective actions. (December 1996)

e. All WSCC members shall provide the data requested by other members required for system monitoring and on-line security programs. In conjunction with NERC SPTF requirements, the data shall be exchanged by April 1997.

f. The WSCC Dispatcher Training Subcommittee (DTS), in conjunction with BPA, PGE, and PAC shall evaluate and report to CMOPS whether the dispatcher response to the Keeler-Allston outage was proper and recommend appropriate actions. (December 1996)

g. BPA shall ensure, and report to CMOPS, that its dispatchers are trained and have appropriate guidelines regarding actions to be taken when they encounter stressed or unusual operating conditions for which there are no prescribed operating instructions. The WSCC Dispatcher Training Subcommittee shall similarly develop generic guidelines for all WSCC members. (December 1996)

h. The WSCC PCC/OC Joint Guidance Committee shall review methodologies being used for off-line studies and develop a process that will reasonably ensure that all credible contingencies are considered both in rating studies and in operating studies. (December 1996)

i. The WSCC Intertie Study Group (ISG) shall investigate, and make appropriate recommendations regarding, the conditions of August 10, including increased system stress due to simultaneous transfers from British Columbia to the Northwest and from the Northwest to California and determine the impact that the Canadian transfers had on the severity of this contingency. The effects of Montana-Northwest and Idaho-Northwest (in both directions) transfers shall also be studied. (December 1996)

j. The Northwest Power Pool (NWPP) Transmission Planning Committee (TPC) shall investigate and determine appropriate operational limits for several portions of the I-5 corridor between Seattle and Portland, including the Keeler-Allston cut plane. This cut plane shall include appropriate transmission lines on the west and east sides of the Cascades. (May 1997)

   Status: The Seattle-Portland (SeaPort) study group was formed by the NWPP-TPC to review critical paths along the I-5 corridor between Seattle and Portland associated with the 3,150 MW BCHA-to-Northwest path uprate planned for completion in 1997. This planning study was agreed upon by BPA, PGE, and PAC to facilitate acceptance of the WSCC Facilities Rating process Phase III status of the BCHA-to-NW uprate. Participation in this study group was open to all interested parties. One portion of these studies focused on the Keeler-Allston 500-kV outage and potential overloads on the underlying transmission lines. The report on the Keeler-Allston path was presented to the SeaPort group in May 1996. Shortly thereafter, a presentation was also made to the NWPP-TPC. The effort to compile all of the sections of the study into a comprehensive report was in progress at the time of the August 10 disturbance. This comprehensive report was not yet available to the NWPP-TPC or the WSCC. Following the August 10 disturbance, an evaluation is being done, factoring in additional generation patterns on the existing system as well as the future system.

3. **Conclusion:** A wide variety of conditions and contingencies must be looked at to ensure that the system is planned and operated within the WSCC Reliability Criteria. Nevertheless, it is recognized that improbable conditions can develop that will lead to system separation across major transfer paths, such as the COI and other paths.

   Recommendation: The Technical Studies Subcommittee (TSS) shall report (to PCC) to what extent studies have been run to determine the consequences of loss of the COI and other critical paths and what mitigative measures are in place to minimize the consequences of such disturbances. (December 1996)

4. **Conclusion:** Immediately following the loss of the Ross-Lexington 230-kV line and the Merwin-St. Johns 115-kV line, the McNary units began tripping due to excitation system protection problems, withdrawing substantial real, reactive, and inertial support from the system. Three McNary units also tripped prior to COI separation during the July 2 disturbance and were identified in the disturbance review.

   Recommendation:

   a. USCE shall review and report to CMOPS whether exciter protection at McNary was proper on both July 2 and August 10, identify why the McNary units tripped and take appropriate action so that undesirable unit tripping will not occur. (December 1996)

      Status: On August 16 and August 17, work was completed to adjust the McNary voltage regulators for units 1-12 and 14. The WSCC Intertie Transfer Capability Policy Committee will review corrective measures. Work is also underway to change taps on all 13.8/230-kV transformers at the McNary powerhouse to increase the 230-kV voltage. Testing underway suggests the problem was false tripping of the phase imbalance relay on the exciter system. By September 11, most testing and corrections were completed at McNary powerhouse. Replacement parts for the faulty relay have been ordered and modifications will be completed in November 1996.

   b. USCE shall review and test their generating unit exciters in the Northwest to ensure proper operation of exciter controls and protection. Results should be properly modeled by BPA in system studies and actions taken by BPA and USCE reported to CMOPS. (December 1996)

   c. The WSCC Control Work Group (CWG) shall determine what tests need to be applied to generating unit exciters to ensure proper operation of exciter controls and protection. They shall also determine what unit MVA level must be tested and develop a procedure to ensure uniform testing, including the frequency of testing and a recommended priority list of units to be tested first. (The CWG work must be completed by November 1, 1996.) All generation owning and operating entities in the WSCC region shall perform the prescribed testing and report to CMOPS. (June 1997) The results should be used to properly model generating units in system studies, and actions taken reported to CMOPS. (June 1997)

d. The WSCC ISG shall determine the effect of the McNary and other Northwest units on system dynamic and voltage stability. (December 1996)

e. Conclusion 1, recommendation a of the July 2, 1996 disturbance report states "Idaho Power Company, PacifiCorp, Bonneville Power Administration (BPA), and other Northwest area entities shall reduce scheduled transfers to a safe and prudent level until studies have been conducted to determine the maximum simultaneous transfer capability limits and to thoroughly evaluate operating conditions actually observed on July 2." BPA shall determine and report to CMOPS why McNary problems were not considered in establishing new COI, BCHA-NW, and other operating limits following the July 2 disturbance and prior to the August 10 disturbance. (October 1996)

f. BPA shall also determine why corrective measures at McNary were not implemented prior to increasing AC Intertie operating limits after the July 2 limits were imposed and report to CMOPS. (October 1996)

g. BPA, USPN and USCE shall ensure that transmission planning models are accurate and reflect the up-to-date capability of the system. (October 1996)

h. BPA, USCE, and USPN shall review the adequacy of their inter-organizational communications and shall jointly plan and initiate corrective actions to their respective systems to ensure reliable operation. (October 1996)

5. **Conclusion:** During the tripping of the McNary units, 0.2-Hz power system oscillations were initiated and increased in magnitude.

Recommendation:

a. The WSCC ISG shall investigate the cause of the undamped oscillations and make recommendations. (December 1996)

b. The WSCC CWG shall review the number of power system stabilizers (PSS) in service at the time of the disturbance and make appropriate recommendations. (March 1997)

c. The WSCC ISG shall determine whether high levels of excitation made PSS ineffective and make appropriate recommendations. (March 1997)

d. The WSCC CWG shall review the application and settings of PSS to determine adequacy and make appropriate recommendations. (March 1997)

e. The WSCC Technical Studies Subcommittee (TSS) shall review the feasibility and desirability of implementing other oscillation damping controls, such as high voltage direct current (HVDC) modulation and make appropriate recommendations. (June 1997)

f. All WSCC owners of generators, in conjunction with the WSCC TSS and CWG shall assess whether installed excitation systems and PSS on units with capacity of ten MW or larger, are properly tested, tuned, and correctly modeled in transient stability studies and make appropriate recommendations. (March 1997)

6. **Conclusion:** COI operational limits, and any misjudgment in establishing those limits, can have a profound effect on the entire WSCC Interconnection. Although the COI operating limits and associated high transfers were not the root cause of the disturbance, they contributed to the overall severity of the disturbance. At the time of the August 10 disturbance, the COI schedule was 4,285 MW and actual flow was 4,350 MW. The operating limit at the time (based on the nomogram) was 4,740 MW. The operational limit in place at the time of the disturbance had been developed by BPA, PG&E, IPC, and PAC after the July 2 disturbance, with only cursory review by other WSCC parties.

Recommendation:

a. WSCC shall form an Intertie Transfer Capability Policy Committee to ensure that NW imports/exports, including COI, Midpoint-Summer Lake, BCHA-NW, NW-Montana and other transfer levels are maintained at safe levels. They shall have the authority to raise or lower operational limits. As agreed upon at the August 12 emergency meeting of the WSCC Executive Committee, approval shall be required from the Intertie Transfer Capability Policy Committee to exceed north to south transfer levels of 3,200 MW at the California-Oregon Border. Subsequent technical discussions led to allocating a north to south limit on the Pacific HVDC Intertie (PDCI) of 2000 MW unless the Midpoint-Summer Lake 500-kV line flow exceeds 200 MW into Summer Lake, at which point the PDCI may be loaded to 2200 MW. A WSCC-wide process using the WSCC Intertie Study Group and the Intertie Transfer Capability Policy Committee shall be developed and implemented for the interim review of changes to operating procedures and operating limits affecting the Northwest interconnected system. This review function is for operational limits and shall not replace WSCC's established project rating review process and shall not be used to establish ratings higher than those currently existing. This process shall be expanded to encompass all major WSCC transfer paths. (October 1996)

b. The WSCC ISG shall identify and report to CMOPS the operating practices needed to ensure that credible generation and transmission outages within the

Interconnection do not result in the loss of the California-Oregon Intertie. The WSCC members shall implement revised operating practices as appropriate. (April 1997)

7. **Conclusion:** In the hour and a half prior to the disturbance, BPA's Big Eddy-Ostrander, John Day-Marion, and Marion-Lane 500-kV lines were forced out of service. Local load area voltage adjustments were made; however, no vulnerabilities were identified by BPA dispatchers and no changes were made to interarea transfers or internal line loadings to reduce system stress. It is not yet known to what degree these outages contributed to the severity of the disturbance. No BCHA-NW or other COI limits had been identified in relation to these outages. Had a need for limits related to these line outages been identified, ample time was available to make system adjustments.

   Recommendation:

   a. BPA shall determine what tools and information are needed to recognize and deal with potential system problems such as those experienced on August 10, and ensure that its operators are informed and trained to respond to such operating problems. BPA shall ensure that operating procedures are in place to mitigate potential operating problems before they escalate and cause reliability problems. BPA's actions shall be reported to CMOPS and the WSCC SPTF. (December 1996)

   b. WSCC's Intertie Study Group shall investigate the impact of the Big Eddy-Ostrander and John Day-Marion-Lane line outages. This investigation shall determine whether the Keeler-Allston and/or Keeler-Pearl line outage would have overloaded the Ross-Lexington 230-kV, PacifiCorp's Merwin-St. Johns 115-kV and PGE's 230-kV Trojan lines or resulted in voltage collapse if these three lines had still been in service. (December 1996)

   c. BPA shall implement various off-line, on-line, and real-time monitoring tools to identify at-risk system operating conditions. (Report status to CMOPS by December 1996 and implement by June 1997)

8. **Conclusion:** While the outage of the Big Eddy-Ostrander 500-kV line was known to PGE and the John Day-Marion 500-kV line outage was known to PG&E by inter-utility data exchange, the three 500-kV line outages experienced by BPA during the hour and a half prior to the disturbance were not reported to other WSCC members, precluding their ability to take mitigating actions had they perceived a need for such action.

   Excerpt from the WSCC Procedure for Coordination of Scheduled Outages and Notification of Forced Outages:

"A. Each WSCC Member System which owns or operates a key generation or transmission element scheduled to be removed from service or which has been forced out of service is responsible for notifying the other WSCC members via the WSCC Communication System of the facility outage. Key facilities are those which are considered important to interconnected system operation by the system which owns the facilities. Key facilities generally include:

.
.
.

3. Transmission operated at 230-kV and higher that can significantly affect interarea system operation ... "

Up to this time, BPA had not considered the named lines as key facilities for reporting.

Recommendation:

a. CMOPS shall review WSCC's policies, procedures, and criteria for reporting key facility outages (considering that lightly loaded lines are an important source of VARs and provide system support during disturbances) and implement improvements and eliminate ambiguity in reporting requirements. This review shall include lower voltage lines similar to those out of service on the BPA system prior to the August 10 disturbance and should address key generating facilities as well. (December 1996)

b. BPA shall review its criteria for designating key facility outages for reporting and indicate why the lines were not designated as "key" facilities and why the outages prior to the disturbance were not widely reported to other WSCC members. (December 1996)

c. BPA shall ensure its system operators are trained to recognize and report critical and abnormal system conditions and key facility outages to WSCC, and shall develop appropriate tools, such as on-line power flow, to aid in these assessments. (December 1996)

9. **Conclusion:** On August 10, the Big Eddy-Ostrander, John Day-Marion 500-kV, Keeler-Allston 500-kV, and Ross-Lexington 230-kV lines were faulted due to conductors flashing over to trees in the right-of-way. All of these outages are the result of inadequate right-of-way (ROW) maintenance by BPA. During the period from June 1 to August 9, a total of five 500-kV line outages (two of these were the same problem on the same line within 40 minutes), and two 115-kV line outages (both momentary outages on the same line within two days of each other) on the BPA system were caused by flashovers to trees. BPA has 4,447 miles of 500-kV, 5,233 miles of 230-kV, and 3,676 miles of 115-kV lines.

Recommendation:

a. BPA shall submit a copy of its tree-trimming and line-patrolling procedures as of August 10 to CMOPS, identifying what parts of the procedure had not been complied with (if any) as of August 10, including reasons for any noncompliance. Dollar amounts budgeted and actual expenditures for tree trimming for 1993 through 1996 shall also be provided. (September 1996)

b. BPA shall determine why the trees that resulted in the flashovers on the lines involved were not identified and removed or cut to design clearances prior to the incident on August 10 and report to WSCC. (September 1996)

c. BPA shall determine why identified danger trees were not removed and shall reevaluate procedures, environmental impacts, and legal requirements for removing danger trees affecting fire safety and reliability. (December 1996)

d. BPA shall report to WSCC what actions have been taken since August 10 to improve its tree-trimming procedures and describe any ongoing efforts to improve their effectiveness. (September 1996)

e. All transmission-owning member systems shall review their tree-trimming programs to ensure that they are adequate and shall provide information to WSCC that indicates any changes (including budgeted monies) made to the programs over the past two years and/or that are intended to be made in the near future. (September 1996)

f. All transmission owning members shall evaluate the need for changes in the tree-trimming policies of the U.S. Forest Service and other federal land agencies and submit recommended enhancements to WSCC. Canadian and Mexican members shall evaluate the need for change in their respective jurisdictions. (December 1996)

10. **Conclusion:** The system oscillations increased until voltage finally collapsed on the COI, leading to the COI opening and the subsequent formation of four islands in the WSCC. Generating units in the Northwest (such as Hermiston, and Coyote Springs) did not respond dynamically or in the steady state with reactive support as predicted in studies. The level of dynamic reactive support from generation at the northern terminus of the COI and PDCI has been greatly reduced by fish operation constraints, particularly at The Dalles.

Recommendation:

a. By November 1997, the WSCC CWG shall determine what tests should be applied to generating units to determine their steady state and dynamic reactive capabilities and provide appropriate guidelines. They shall also determine what unit MVA level must be tested and develop a procedure to ensure uniform testing, including the frequency of testing, and a recommended priority list of units to be tested first. (The CWG work must be completed by November 1, 1996.) Generation-owning and operating entities in WSCC shall test, or provide proof of tests on, their generating units with capacity of ten MW or greater to determine their steady state and dynamic reactive capabilities, adjust study assumptions to match the test results, and report to CMOPS. (June 1997)

b. BPA shall take into account fish spill requirements at The Dalles, John Day, McNary, and other Northwest hydro generation plants when determining transmission capabilities. BPA shall report to CMOPS how this will be accomplished. Special attention shall be given to the loss of dynamic reactive reserves from these plants. (December 1996)

c. BPA shall report to CMOPS regarding actions taken to ensure that instructions to system operators relating to the reactive requirements of the system under various contingency conditions are adequate. These instructions shall include actions required to mitigate the loss of reactive margin, such as bringing generating units on line, switching shunt devices, reducing schedules and line loadings, and manually shedding load. (December 1996)

d. The WSCC PCC/OC Joint Guidance Committee shall review the recommendations made in the NERC publication entitled "Survey of the Voltage Collapse Phenomenon" and make appropriate assignments to review the recommendations and ensure that they have been appropriately implemented within the Western Interconnection. (June 1997)

e. The WSCC PCC shall develop reliability criteria for reactive reserves and reactive margin. (December 1996)

f. Generation-owning and operating entities in WSCC shall ensure that generating units will provide proper steady state and dynamic voltage support, through actions such as keeping voltage regulators on automatic voltage control. The MORC Work Group shall develop suitable modifications to the criteria, including criteria relating to constant power factor control. Results shall be reported to CMOPS. (June 1997)

g. BPA and all other control areas shall perform reactive margin studies for worst case scenarios and report study results to the WSCC OC. (June 1997)

h. PGE, PAC, and USCE, in conjunction with the WSCC ISG shall determine and report to CMOPS the extent to which Coyote Springs and Hermiston generation were or were not providing effective voltage control and reactive support in the McNary area during this disturbance and make recommendations as appropriate to enhance system performance. (December 1996)

i. The WSCC ISG shall determine whether circuit outages in the Portland area impacted the simultaneous transfer capability of the COI and other paths to the Northwest. (December 1996)

j. BPA, USPN and USCE shall determine and report to CMOPS how plant reactive power may be increased by considering options such as operating units in condensing mode or with more units on line for a given power level (reduced efficiency), or other alternatives. (December 1996)

k. The WSCC TSS shall respond to regulatory questions about the use of flexible AC transmission system (FACTS) devices and other voltage support devices to enhance system performance and make recommendations to the PCC. (June 1997)

l. The WSCC ISG shall develop nomograms for Northwest Intertie operations, including the COI, PDCI, BCHA, Idaho, Montana, and other transfer paths, that will ensure reliable operation. Such nomograms shall consider the generation availability and load level of the Northwest. BPA shall provide information to WSCC illustrating actual flows relative to the nomograms on a daily basis until such reporting is no longer deemed necessary. (December 1996)

m. The WSCC member systems shall evaluate the need for and report to WSCC regarding the application of undervoltage load shedding on their individual systems to enhance interconnected system reliability. (March 1997)

11. **Conclusion:** Boardman coal plant responded dynamically to the loss of the Keeler-Allston 500-kV line, increasing its reactive output to 157 MVAR at Slatt, but backed down to 78 MVAR, by operator intervention, after approximately 30 seconds.

    Recommendation: PGE shall determine whether the response of Boardman to this disturbance was proper. (November 1996)

12. **Conclusion:** Special operations to protect fish (such as reducing generation and increasing spill at The Dalles) reduced the amount of real power, reactive power, and inertial support provided to the system, and therefore adversely impacted system reliability.

    Recommendation: The WSCC ISG shall model these special fish-protecting operations in the studies they are conducting to determine the impact on COI transfer capability, paying particular attention to the loss of reactive power support due to these operations. The WSCC ISG shall report its findings and recommendations to CMOPS. (April 1997)

13. **Conclusion:** On August 10, temperatures were high throughout much of the WSCC region. As a result, loads in some areas were very high for a Saturday, including air

conditioning induction motor loads. These load characteristics may have had a significant effect on the nature and severity of the disturbance.

Recommendation: The WSCC ISG shall determine and report to WSCC regarding the impact of load levels and load characteristics on this disturbance and make appropriate recommendations to enhance study capabilities, improve system models, and improve system performance. (June 1997)

14. **Conclusion:** Upon opening of the COI, the Northern California and Southern Islands lost nearly 28,000 MW of load and approximately 20,000 MW of generation. A similar separation occurred on the COI on July 2, 1996. In a generation deficient condition, the intended outcome is for only load to trip. Unlike the July 2 disturbance, in this instance, system performance in the Northern California and Southern Islands was adversely affected by the uncontrolled tripping of a substantial amount of generation.

Recommendation:

a. Generation owning entities that lost generation in the low frequency islands shall report to the Relay Work Group the reasons for units tripping and any corrective actions taken since August 10. (October 1996)

b. The WSCC Relay and Control Work Groups shall determine why actions taken in response to the December 14, 1994, system disturbance were not effective in preventing the uncontrolled loss of generation on August 10 and recommend corrective actions. (March 1997)

c. The WSCC CMOPS shall determine why the frequency could not be restored without manual load shedding after extensive underfrequency load shedding and make appropriate recommendations. (March 1997)

d. All WSCC members, or groups of members, experiencing low frequency in this disturbance shall analyze whether operation of underfrequency load shedding systems was proper and appropriately coordinated among entities within each island. Deficiencies shall be reported to WSCC and corrective measures implemented. (December 1996)

   Status: Three of the six load banks (with a load of 154 MW at the time of the disturbance) in LDWP's 58.5 Hz underfrequency load shedding block failed to trip. An underfrequency relay on one of the banks was found to be defective and replaced. The relays on the other two banks were tested and found to be set within tolerance (58.49 Hz) and operating properly. These relays apparently did not trip because the frequency was not low enough for long enough to activate them.

e. The WSCC OC shall initiate a study to review the coordinated underfrequency load shedding programs on a subregional and regional scale. The coordination of underfrequency load shedding with underfrequency generator protection shall be included in the study. Recommendations shall be developed and implemented. (June 1997)

15. **Conclusion:** Colstrip Units 1, 3, and 4 tripped by Acceleration Trend Relay action during the disturbance.

    Recommendation: MPC shall determine and report to CMOPS whether Colstrip tripping was appropriate and take corrective action if needed. (December 1996)

16. **Conclusion:** At the time of the August 10 disturbance, the Northeast/Southeast Separation Scheme was out of service in accordance with the WSCC Committed Action Plan Agreement. The power system separated on out-of-step across the NE/SE boundary 1-2 seconds after it would have separated had the scheme been in service. It is possible that the faster, more coordinated separation provided by the scheme could have lessened the impact of this disturbance in the Southern Island.

    Recommendation: The WSCC ad hoc Controlled Islanding Work Group shall study the impact on this disturbance of not having the NE/SE Separation Scheme in service and make appropriate recommendations. This study shall also consider direct load tripping in the southern island and the northern California island as remedial action for loss of the COI and the negative impact of a false operation of the NE/SE Separation Scheme. (June 1997)

17. **Conclusion:** The NE/SE Separation Scheme was placed in service at 0101 PAST on August 11, 1996, after some discussion among the major participants in the scheme. This scheme had been out of service since the completion of the California-Oregon Transmission Project (COTP) except under certain loading conditions and when the COTP is out of service. Notification was posted by APS on the WSCC Communication System. However, SPP was not informed by PG&E of the change in accordance with procedures and did not enable its part of the scheme until about three days later.

    Recommendation:

    a. The WSCC OC shall review the procedure for notification of status changes for this scheme and make appropriate changes. Operating and planning engineers shall also be notified to ensure that future changes in status of the scheme are properly coordinated. (March 1997)

    b. The WSCC OC shall evaluate a means to include feedback in the notification process to ensure notifications have been received and read. (March 1997)

    c. PG&E shall review and report to CMOPS regarding procedures to ensure appropriate communication of changes in status of the NE/SE Separation Scheme. (October 1996)

d. SPP shall report to CMOPS why it did not act upon the WSCC message informing members of the NE/SE Separation Scheme activation.

e. The PCC/OC Joint Guidance Committee shall determine whether it is prudent to continue with the NE/SE Separation Scheme in service and make appropriate recommendations. (November 1, 1996)

18. **Conclusion:** Multiple transmission paths opened by out-of-step relay action, separating the main WSCC loop into four electrical islands.

    Recommendation: The WSCC ad hoc Islanding Work Group shall investigate and report to CMOPS the contributing causes of the separations and recommend appropriate actions to enhance system performance. (March 1997)

19. **Conclusion:** Governor response to high frequency resulted in increased flows into Alberta from British Columbia. Five minutes into the disturbance, the increased flow caused low voltage and high current which resulted in the tripping of the interconnection between BCHA and TAUC.

    Recommendation:

    a. BCHA and TAUC shall evaluate why the tie tripped, take appropriate action and report to CMOPS. (October 1996)

    b. TAUC and BCHA shall determine and report to CMOPS whether governor response was appropriate and implement any necessary corrective measures. (October 1996)

20. **Conclusion:** The frequency stayed high in the Northern Island (about 60.4 Hz for fourteen minutes, crossing 60 Hz after seventeen minutes). After returning to 60 Hz, the frequency rose again to 60.04 Hz and remained there for 50 minutes. Despite having no direct schedules to California, BCHA unilaterally cut schedules by approximately 600 MW to reduce island frequency, absorbing 2,200 MWH of inadvertent interchange over the next three hours.

    Recommendation:

    a. The WSCC CMOPS shall determine why frequency did not return to normal in a timely manner and recommend corrective action. (December 1996)

    b. BPA, PAC, BCHA, PSPL, PGE, and other Northwest island parties shall evaluate and report to CMOPS the role scheduling played in keeping the frequency high. The parties shall determine what schedules, if any, were not cut that should have been. (December 1996)

c. The WSCC SPWG shall review and report the process for rapid changes of schedules on the COI and PDCI. They shall determine the required time for operator initiated emergency schedule changes and the effectiveness (system response in time, MW, and frequency) of those changes. (December 1996)

21. **Conclusion:**

Southern Island frequency was below 59.0 Hz for twenty minutes and below 60 Hz for over an hour.

Northern California Island frequency hovered around 59.5 Hz for 75 minutes. Automatic load restoration impeded frequency restoration in the Northern California Island. Low frequency in the Southern and Northern California Islands impeded the restoration process by preventing synchronization of any two islands.

Recommendation:

a. All member systems shall review and report to CMOPS regarding the problems associated with coordination of automatic and manual load restoration and take appropriate action. (March 1997)

b. CMOPS and the WSCC SPTF shall review the role and authority of the WSCC Coordinating Centers in facilitating load restoration and develop recommendations as appropriate for improved performance. (December 1996)

c. Each island's utilities shall determine and report to CMOPS regarding any other factors that delayed the recovery of frequency and recommend corrective measures. (December 1996)

22. **Conclusion:** Protective relays on critical lines appeared to have operated properly with the exception of the Merwin-St. Johns 115-kV line, which was tripped by a malfunctioning zone 1 KD relay.

Recommendation: PAC shall investigate this relay misoperation, take corrective action and report to CMOPS. (November 1996)

23. **Conclusion:** The Keeler SVC tripped 1.5 seconds after the COI separation by undervoltage relaying. LDWP similarly lost PDCI Converters 1 and 2 at Sylmar when their cooling systems tripped after the Sylmar voltage dropped to 0.68 pu. LDWP also lost SVCs at Adelanto and Marketplace because of low voltage.

Recommendation:

a. BPA shall investigate and correct the problem that tripped the Keeler SVC and shall report its findings and actions to CMOPS. (March 1997)

b. LDWP shall investigate and correct the problems causing the loss of the Sylmar DC auxiliary systems and system SVCs and report its findings to CMOPS. (March 1997)

c. Under the direction of CMOPS, all WSCC members shall review their own SVCs and any other critical, voltage-sensitive power system equipment to determine if they may have similar problems and implement corrections as required. (March 1997)

24. **Conclusion:** The PDCI power levels fluctuated substantially in response to changing AC voltage.

Recommendations:

a. BPA and LDWP shall determine and report to CMOPS as to whether the HVDC response, including the actions of protection systems that reduced the DC capacity, was appropriate and/or contributed to the severity of the disturbance and shall take action as appropriate. (December 1996)

b. The WSCC ISG shall review and report to CMOPS as to whether the PDCI response during the oscillations was a contributing source of negative damping and reduced synchronizing power and make appropriate recommendations. (December 1996)

25. **Conclusion**: LDWP manually blocked the PDCI due to the uncontrolled loss of equipment and an excessive (1,000 MVAR) converter reactive power draw from the AC system at Sylmar. This may have contributed to manual load shedding in the Southern Island.

Recommendation: LDWP shall assess and report to CMOPS the appropriateness of interrupting imports through the PDCI while in a low frequency island and correct procedures if necessary. (October 1996)

Status: The LDWP senior load dispatcher was fully aware of the implications of blocking a source of import power into a low frequency island when he made the decision to do so. The LDWP dispatcher decided to block the PDCI because he believed the excessive reactive power demand at Sylmar, coupled with the uncontrolled loss of PDCI equipment over the previous ten minutes (and the perceived threat of additional uncontrolled loss of equipment) was a greater threat to the security of the island than was the loss of the power being imported**.**

26. **Conclusion:** WAPA lost the two Glen Canyon-Flagstaff-Pinnacle Peak 345-kV lines when the Pinnacle Peak 345/230-kV transformers opened due to overexcitation. The Glen Canyon end of the lines subsequently opened due to high voltage resulting from the line charging of the open-ended lines. The transformer overexitation condition

lasted for nearly two hours, resulting in the unavailability of Glen Canyon generation, though it was critically needed as a resource during recovery from the disturbance.

Recommendation:

a. WAPA shall test the transformer overexcitation relays, review relay settings, implement appropriate corrective measures and report to CMOPS. (October 1996)

b. WAPA shall investigate and report to CMOPS regarding the cause of the lines that tripped, isolating the Glen Canyon plant from the power system, and implement appropriate corrective measures. (October 1996)

27. **Conclusion:** The first COI line was restored at 1818 PAST, but schedules on this path were not resumed until the hour ending 2100 PAST. The delay hampered load restoration efforts in the Northern California Island. (Remaining interconnections were also restored in this period.)

    Recommendation: PG&E and BPA shall determine and report to CMOPS the cause of the delay in resuming scheduling and take appropriate action. (October 1996)

28. **Conclusion:** Several control centers including APS, WAMP, TEP, TNP, and SRP lost their Energy Management Systems (EMS) during the disturbance. The Uninterruptible Power Supply (UPS) at APS failed and the EMS was down for just over an hour. TNP lost its EMS computer, apparently due to alarm management problems. SRP lost its EMS three times during the disturbance. WAMP lost its EMS due to failure of its backup power supply system. It also lost communications, and PG&E was unable to contact WAMP to request additional generation. USPN lost its SCADA system at Grand Coulee, hampering efforts to control local circuit breakers and other critical facilities. Additionally, PAC lost its Portland EMS due to UPS failure, but continued operations through its back up control center.

    Recommendation: The WSCC EMS Work Group and utilities that experienced trouble with their control centers shall determine and report to CMOPS the causes of these failures and take appropriate corrective action. (December 1996)

29. **Conclusion:** Within 30 minutes after the disturbance began, the WSCC office was receiving calls from news media reporters demanding information about the disturbance. The WSCC Staff was unable to provide answers, not having been notified that a disturbance was in progress. Dispatchers were receiving calls directly from the news media, distracting them from system operations. The media representatives had reportedly received the dispatchers' phone numbers from the utility's security personnel and/or from other utilities. A significant problem during emergencies is phone calls unrelated to determining the problem and restoring the system.

Recommendation:

a. The four Coordinating Centers shall develop procedures to notify WSCC staff no more than ten minutes after a major disturbance is confirmed and provide known information. (October 1996)

b. WSCC members shall develop and implement procedures for reporting system disturbance information on the WSCC Communication System within thirty minutes to allow all parties to assess conditions and develop an optimal response to the disturbance. (October 1996)

c. All member systems shall have policies in place to ensure dispatch phone numbers are not revealed to the public or news media without *prior* permission of the utility. (October 1996)

d. CMOPS shall develop a requirement within MORC specifying the minimum technical and executive resources which will be available 24 hours per day for system emergencies. (December 1996)

e. All WSCC members shall provide their operating management's (up to Council Representatives) cellular phone numbers and home phone numbers to the WSCC staff for use in coordinating the collection and dissemination of information regarding large scale system disturbances in the WSCC region. In addition, the WSCC staff shall compile a list of control center phone numbers. (October 1996)

f. The WSCC staff shall implement procedures to issue its initial press release to the members within thirty minutes of notification and to the media within one hour of notification of a large scale system disturbance in the WSCC region. (October 1996)

g. The WSCC staff shall have at least one cellular phone and a pager to be monitored continuously for use in coordinating the reporting of information regarding major system disturbances in the WSCC region. (October 1996)

h. The WSCC staff shall develop contingency plans for coordinating disturbance reporting information in the event the WSCC office is impacted by a disturbance. (June 1997)

30. **Conclusion:** Analysis of this disturbance was impeded by the lack of dynamic information at key points on the system, such as on the Midway-Vincent tie, west of Borah, the NE/SE cut plane, and other lines most likely to be involved in islanding or voltage collapse.

Recommendation: The WSCC SPTF shall review the need for improved dynamic monitoring at key points and critical potential separation points in the system and shall make recommendations, including the time frame for implementation. Dynamic records shall be time tagged and include both pre-and/post-disturbance data. Key data shall be monitored to improve system security. (June 1997)

31. **Conclusion:** In response to this disturbance, utilities' energy traders, generation operators, and transmission operators found it necessary to coordinate closely to restore the system. As members restructure to comply with FERC Order 889, such close coordination may be limited.

    Recommendation: The WSCC OC shall assess the potential impact of FERC Order 889, Standards of Conduct, on coordination between generation marketers/owners and transmission operators during disturbances and make appropriate recommendations to improve the coordination of system restoration. (March 1997)

32. **Conclusion:** The July 2 and August 10 disturbances emphasize the need for timeliness in the disturbance report recommendation resolution process. Examples of recommendations made as a result of previous disturbances that continue to be factors in more recent disturbances include the recommendations relating to controlled islanding, criteria for multiple contingencies, criteria for relay failures, and coordination of underfrequency load shedding.

    Recommendation: The WSCC Board of Trustees shall implement policies as needed to ensure that critical disturbance report recommendations are completed expeditiously. This includes ensuring adequate manpower and capital resources are available to implement these recommendations. (January 1997)

III. PREDISTURBANCE CONDITIONS

Most utilities had high Saturday loads as a result of hot summer temperatures in most of the western states prior to the disturbance. Flows on significant paths are listed in the following table.

Path	Rating	Flows	Percent of rating
Canadian Intertie between BCHA and BPA	2,300	2,300 MW North to South	100
California-Oregon Intertie	*4,800	4,350 MW North to South	91
Midpoint-Summer Lake	1,500	600 MW East to West	40
Pacific DC Intertie (at converter station)	3,100	2,850 MW North to South	92
Midway-Vincent	3,000	1,380 MW North to South	46
East of Colorado River Path	7,365	3,225 MW East to West	44
Northeast/Southeast Path	1,700	1,058 MW North to South	62

* Scheduling limit was 4740 MW due to the operating nomogram prepared after the July 2 disturbance.

Transmission lines out of service:

1. The Big Eddy-Ostrander 500-kV line tripped at 1406 PAST.
2 At 1452, the John Day-Marion 500-kV line tripped. Both the Big Eddy-Ostrander and John Day-Marion outages were caused by the lines flashing over to trees.
3. The John Day-Marion outage also forced out the Marion-Lane line due to system configuration (circuit breaker 4365 out of service).

Prior to these outages, the lines noted above were lightly loaded. The Big Eddy-Ostrander 500-kV line directly serves the Portland area. The John Day-Marion 500-kV line supports the Portland area from the south via the Marion-Pearl 500-kV line.

In addition to these outages, the Keeler 500/230-kV transformer was out of service for tap changer modifications and breaker replacement at Keeler. As a result, the Keeler +/-300 MVAR Static VAR Controller (SVC) was limited in its ability to support the 500-kV system.

In the Willamette Valley region, BPA had two 500-kV circuit breakers out of service for replacement: CB 4365 at Marion and CB 4322 at Keeler. The Allston terminal of the 115-kV St. Helens-Allston line was open due to the degraded thermal capability of this 115-kV line. Its use has been limited to radial operation. Generation at The Dalles was at reduced levels due to a 64 percent spill requirement for fish measures. Prior to the disturbance, no voltages or line loadings were in violation of established limits.

IV. DETAILED DESCRIPTION

DESCRIPTION OF DISTURBANCE

At 1548 PAST on August 10, 1996, a major disturbance hit the Western Interconnection, forming four islands. Conditions prior to the disturbance were marked by high summer temperatures (near or above 100 degrees) in most of the region, by heavy exports (well within known limits) from the Pacific Northwest into California and from Canada into the Pacific Northwest, and by the loss of several 500-kV lines in Oregon.

The COI North-to-South power flow was within parameters established by recent studies initiated as a result of the July 2 disturbance. The flow on the COI totaled approximately 4,350 MW; the power order on the PDCI was 2,848 MW.

EARLIER LINE OPERATIONS

At 1401 PAST, the Big Eddy-Ostrander 500-kV line relayed three-pole when it flashed to a tree. The PGE terminal of the Big Eddy-McLoughlin 230-kV line relayed and reclosed for this fault close to the Ostrander end. The Big Eddy-Ostrander line tested good and was returned to service at 1403. At 1406, the Big Eddy-Ostrander line relayed single-pole (A-phase), reclosed, tripped three-pole, and stayed out of service. PGE’s terminal of the Big Eddy-McLoughlin 230-kV again relayed and reclosed. The 500-kV line had flows of 90 MW with 130 MVARs into the Big Eddy bus and 86 MVAR into the Ostrander bus. Around 1410, BPA SCADA logged low voltage alarms from Alvey (236-kV), Slatt (529-kV), Big Eddy (236-kV), and Vantage (239-kV). This low voltage was corrected by shunt reactor switching at the Grizzly 500-kV bus and by shunt capacitor switching at the Alvey 230-kV busses. At 1446, the Vantage 500/230-kV transformers were lowered one tap, bringing the Vantage bus voltage to 240-kV.

At 1452:37, the John Day-Marion 500-kV line relayed, reclosed, and tripped to lockout for a C-phase fault when it flashed over to a tree near Marion (tower 122/1). Due to Marion power circuit breaker (PCB) 4365 being out of service, this line outage also forced out the Marion-Lane 500-kV line. The John Day-Marion line tested bad at 1456. When it tripped, the John Day-Marion line was carrying 248 MW to Marion with 207 MVAR into the John Day bus and 35 MVAR into the Marion bus. The Marion-Lane line was carrying 330 MW and 105 MVAR. Following the loss of these lines, the Big Eddy bus alarmed at 235 kV and Slatt at 529 kV. Voltage control switching involved transformer tap changes at Allston and Big Eddy and the 500-kV shunt capacitors at Ostrander. At 1517, Slatt alarmed for below voltage schedule at 529 kV, as did Hanford at 525 kV.

INITIATING EVENTS

At 1542:37, fifty minutes after the John Day-Marion line fault, the Keeler-Allston 500-kV line, carrying 1,300 MW toward Keeler and 110 MVAR into Allston, tripped after flashing to a tree near Keeler. At the time, the current flow was 1,406 amps. The summer rating of this line is 2,900 amps. This also forced the Pearl-Keeler line out of service due to the Keeler 500/230-kV transformer being out of service. At this point, there were five 500-kV line segments out of service, removing several hundred MVAR of reactive support from the system and increasing the reactive requirement as other lines picked up the power flow from the lost lines. BPA SCADA systems received many voltage alarms in the mid-Columbia basin. McNary 500-kV bus, at 519 kV, dropped to 506 kV. The 230-kV bus alarmed at 237 kV (alarm set for 238 kV). Vantage was at 520 kV and the COI was 533-kV at Grizzly and Malin. Twenty and thirty seconds later, the Ross-Lexington 230-kV line alarmed at 1,235 amps (1,050 amp rating) and the Allston-Trojan line alarmed at 1,400 amps (1,315-amp emergency rating). BPA dispatchers requested maximum reactive power boost from John Day and The Dalles within one minute of the Keeler-Allston trip. Loading on the PGE Trojan-St. Marys and Trojan-Rivergate 230-kV lines increased from approximately 325 MW each (780 A) to 560 MW each (1,400 A, 106 percent of the PGE 1,315 A emergency rating). Loading on BPA's Ross-Lexington 230-kV line increased from approximately 330 MW (790 A) to 487 MW (1,237 A, 115 percent of its 1,070 A rating). Prior to the Keeler-Allston trip, the thirteen McNary generating units were producing 860 MW and 260 MVAR.

While the BPA system voltage situation was being assessed (BPA dispatchers were considering the possibility of COI schedule reductions), the Keeler-Allston line was tested from Allston and found bad at 1544 PAST. BPA dispatchers then called Washington Nuclear Power (WNP) Unit 2 (and other plants), requesting maximum reactive boost. Boardman coal plant responded dynamically to the loss of the Keeler-Allston 500-kV line, increasing its reactive output to 157 MVAR at Slatt, but backed down to 78 MVAR, by operator intervention, after approximately 30 seconds. At 1545 PAST, PGE reported to BPA overloads in the Rivergate area.

At 1545, BPA SCADA recorded the McNary 230-kV bus as receiving 347 MVAR from McNary and Hermiston was receiving six MVAR from the transmission system. Coyote Springs was taking seven MVAR from the McNary-Slatt 500-kV line. WNP Unit 2 was supplying 200 MVAR to the Ashe 500-kV bus. The John Day substation was receiving 408 MVAR from the John Day powerhouse. Big Eddy was receiving 77 MVAR total from The Dalles. The McNary generating units had boosted their reactive output from 260 MVAR to 475 MVAR (which was over their maximum sustained MVAR output for that power level) immediately following the Keeler-Allston trip.

At 1547:29, approximately five minutes after the 500-kV line trip, the PacifiCorp Merwin-St. Johns 115-kV line tripped due to a zone 1 KD relay malfunction. (The time stamp noted is from PAC's Portland Area Dispatch SCADA system. This system is not satellite synchronized, therefore, the exact time of the line trip and its place in the sequence of events are not known.) The line had been carrying 86 MW toward St. Johns prior to the disturbance. Merwin and Yale generation was 82 MW, and Swift generation was 207 MW. There were 12 MW flowing from Cardwell to Merwin. The generation connected to this line did not trip and remained connected to the Longview area.

At 1547:36, the Ross-Lexington 230-kV line tripped after sagging too close to a tree and flashing over. This also forced the outage of PacifiCorp's generation at Swift (207 MW) connected to this line. The two Trojan 230-kV lines, now loaded to 150 percent of their emergency ratings, were the only west side ties between Portland and the 500-kV system to the north. There was also a 115-kV line from the north to Astoria, down the coast, that does connect back to the Willamette Valley.

The McNary units boosted their reactive output to 480 MVAR, then to 494 MVAR. They held this level for a short time, then began tripping. Two units tripped at 1547:40, followed by four more units four seconds later dropping the frequency to 59.9 Hz. At 1547:49, another unit tripped, followed eight seconds later by another unit, and another unit fifteen seconds after that. At 1548:47, two units tripped and, at 1549, the last two units tripped. The McNary unit trips the result of erroneous operations of a phase unbalance relay in the generator exciters. Relay replacement is in progress. Following the loss of the McNary units, the Boardman Plant was supplying 275 MVAR to Slatt in response to collapsing voltage while in constant excitation mode.

POWER OSCILLATIONS BEGIN

Following the generation loss at McNary, the power system began experiencing a mild oscillation. Grand Coulee, Chief Joseph and John Day began picking up the lost generation. When McNary generation had dropped to approximately 350 MW, the oscillation became negatively damped. Forty-five seconds after the Ross-Lexington line trip, the Malin 500-kV Shunt Capacitor Group 3 was automatically switched in. This raised the voltage, but the 0.224 Hz system oscillations continued to increase. Five seconds later, BPA's Eastern Control Center (ECC) SCADA operator switched in a 115-kV shunt capacitor group at Walla Walla. SCADA at BPA's Dittmer control center was receiving line load fluctuating alarms.

The PDCI also began to fluctuate in response to the AC voltage. The PDCI power controller maintains the power level by adjusting current without exceeding a 3,100 ampere DC line current limit. If the current reaches this limit, the power level necessarily reduces as the AC voltage declines. The PDCI response during the oscillation indicates that system inertia synchronizing power was reducing (decreasing DC power while the AC power was increasing). At 1548:51, when the AC system oscillations had increased to approximately 1,000 MW and 60 kV peak-to-peak at Malin, the voltage collapsed. At this point, the PDCI power level changed enough to initiate the DC Remedial Action Scheme (RAS) level 1 ten-second sliding window algorithm. This RAS action closed Shunt Capacitor Group 4 at Malin and inserted the Fort Rock series capacitors on all three 500-kV lines south of Grizzly. At the same time, the Buckley-Grizzly line opened at Buckley via zone 1 relay action.

Within the next two to three seconds, the ties between northern California and neighboring systems, and between Arizona/New Mexico/Nevada and Utah/Colorado opened due to out-of- step and low voltage conditions.

OBSERVATIONS/INTERTIE INSTABILITY

The loss of the Keeler-Allston 500-kV line at 1542:37 overloaded the 230-kV lines into the Portland area and led to the loss of the Ross-Lexington 230-kV line at 1548:36. Power shifting east of the Cascades led to additional reactive demands in the McNary area and consequent tripping of all thirteen units at McNary. Finally, growing oscillations reached a level that tripped all three lines of the COI in just over one minute.

Factors which may have contributed to the severity of the disturbance include:

- Reduced reactive margin at McNary and other power plants is not alarmed to the BPA dispatcher. Additionally, low side reactive power output is not available on control center monitors. Either of these items would have indicated a problem before loss of the Keeler-Allston line.
- Protective systems at McNary are designed to transfer regulator control from dynamic automatic mode to manual mode after boosting above the maximum excitation limit for a specific length of time. The unit is supposed to stay connected to the line after this operation but erroneous protective relay actions tripped the units off line.
- Other units in the McNary area were operating on constant power factor control rather than voltage control, preventing these units from providing needed reactive support (Coyote Springs and Hermiston Generation).
- Reactive power limits used on USCE generators are more restrictive than those used in planning and operating simulation studies.
- Some power system stabilizers (to damp system oscillations) were not operational at The Dalles (five units on line, three without PSS) and John Day (13 of 16 units on line, four without PSS) due to plant control problems.
- The present PDCI response to system swings at high current output and low AC source voltages.
- The Dalles generation was at a low level (300-400 MW, five of 22 units on line) due to spill requirements for fish migration.
- AGC systems responded to the loss of McNary generation by picking up most of the generation at plants farther north. This effectively increased the length of transmission circuits between Northwest generation and Southwest loads.

This disturbance has indicated the need to identify strategies that will protect against COI instability for the more severe, unforeseen events such as loss of transmission into the Portland area. It also highlights the need for continued vigilance to ensure that all equipment can be operated to its full rating or to the fullest extent possible and that planning and operational simulation studies correctly represent system limitations.

CALIFORNIA-OREGON INTERTIE SEPARATION

One-and-a-half cycles after the Buckley-Grizzly trip, the Malin voltage had reached 315 kV, and the Malin-Round Mountain No. 2 and No. 1 500-kV lines were tripped by the traveling wave relay switch-into-fault logic at 1548:52.632. (This underreaching-impedance type logic is supervised by a specified low voltage level that has been reached for a period of time and no traveling wave detection. These were the same relays that operated for the July 2 disturbance.) The loss of the two Malin-Round Mountain lines caused the AC RAS to initiate brake insertion and Low generator dropping. One cycle later, the AC RAS High generator dropping algorithm operated. Shortly after Malin-Round Mountain lines tripped, the John Day-Grizzly No. 1 500-kV line tripped at John Day, the Chief Joseph dynamic brake inserted, and the John Day-Grizzly No. 2 500-kV line tripped. Seventy milliseconds after the Malin-Round Mountain No. 2 line tripped, the Captain Jack-Meridian 500-kV line tripped. At the same time, voltage started to decay at the Vincent substation in southern California and units at Chief Joseph and Grand Coulee tripped via RAS action. Forty milliseconds later, the Grizzly-Malin No. 2 line opened at Grizzly, followed in 24 milliseconds by the Grizzly-Captain Jack 500-kV line opening at Grizzly. Less than 20 milliseconds after that, the Captain Jack-Olinda line opened at Captain Jack, completing separation of the California-Oregon Intertie (COI). The North island frequency rose to 60.9 Hz dropping to 60.4 Hz within two seconds where it remained for about fourteen minutes. The frequency crossed 60 Hz three minutes later.

PDCI RESPONSE

During the disturbance, the PDCI experienced several power reductions. Prior to the disturbance, the power order at Celilo was 2,848 MW north to south with all valve groups and converters in operation. There were three power dips during the disturbance. The first power dip was at 1548:52 caused by an AC voltage reduction at Celilo. The DC voltage dropped from 500 kV to 315 kV in response to the fluctuating AC voltage. After the COI separated, the AC voltage returned to normal and the DC power recovered.

The second power dip, at 1548:54, was caused by an AC voltage reduction at Sylmar resulting from the power swing following the opening of the COI. Sylmar reports AC voltages as low as 0.65 pu. The DC voltage dropped as low as 286 kV during this period. There were also commutation failures at Sylmar during this time. The voltage-dependent current limit switched on for a short period to ramp the current orders in both poles to 550 amps. The DC power level reached zero for a short period then recovered when the Sylmar AC voltage increased.

The third power dip on the DC occurred at 1548:58. It was also caused by AC voltage reduction at Sylmar. Sylmar Converters 1 and 2 blocked when the valve cooling systems tripped off due to the low AC voltage. Sylmar Valve Group 5 also blocked at this time, possibly due to loss of cooling flow in the test thyristor valve in that group. At 1549:01, Sylmar Valve Group 7 blocked. Celilo Valve Groups 5 and 7 and Converter 1 blocked in order to match the pole 3 operating voltage allowed by the remaining Sylmar operating configuration. Following this, the DC power level slowly recovered (as the Sylmar AC voltage recovered) to about 1,534 MW.

At 1605:12.4, Sylmar AC Filter Bank 4 relayed due to blown fuses probably caused by high harmonic current resulting from reduced voltage operation after the loss of the other valve groups. No action was taken to replace the lost reactive power from AC Filter Bank 4 because Sylmar's Reactive Power Controller had tripped off at 1548:54 due to low voltage. At this point the PDCI was drawing an estimated 1,000 MVAR from the 230-kV AC system at Sylmar. The LDWP senior load dispatcher, concerned about the excessive reactive power draw and the sequential uncontrolled loss of equipment over the previous ten minutes, ordered the PDCI to be manually ramped down and blocked. The PDCI ramp began at 1606:19 and the PDCI was blocked at 1612.

NORTHERN ISLAND DETAILS

This island consisted of Oregon, Washington, Idaho, Montana, Wyoming, British Columbia, Utah, Colorado, Western South Dakota, Western Nebraska, and Northern Nevada. This island was formed following the separation of the COI and out-of-step tripping on the Northeast/Southeast boundary.

Shortly after the Captain Jack-Olinda line opened, the Malin south bus differentials operated to deenergize the PAC 500/230-kV transformer. The Grizzly-Summer Lake line (and Ponderosa tap) relayed. All remaining lines on the Oregon section of the COI were tripped between John Day and Malin. The loss of the 230-kV connection at Malin subsequently led to the loss of the BPA Malin-Warner 230-kV line as well as PAC connections between Meridian and Redmond. The Lapine-Chiloquin 230-kV, Lapine-Fort Rock 115-kV, Lapine-Midstate Electric 115-kV, Pilot Butte-Lapine 230-kV, Redmond-PacifiCorp 115-kV (Prineville) and 230-kV (Pilot Butte) circuits tripped at 1550.

At 1548, three Columbia Aluminum Company feeders at Harvalum tripped by undervoltage relay within the plant, and 279 MW of load was lost. Also at 1548, three Northwest Aluminum Company feeders were tripped at Harvey, again by undervoltage relay within the plant, interrupting 154 MW of load. All six feeders were restored at 1633.

PAC lost about 450 MW of load, interrupting service to 154,000 customers in portions of southern and central Oregon, and northern California. Power was restored between 1620 and 1701.

MPC Colstrip Units 3 and 4 (750 MW each) tripped by ATR at 1548:53.622; Unit 1 (320 MW) tripped 27 ms later (also by ATR). IPC's CJ Strike Unit 3 (29 MW) tripped at 1549 due to exciter problems. Strike was restored at 1614. Colstrip Units 1 and 3 were restored at 1656 and 1707. Unit 4 was restored at 04:29 on August 11.

In BCHA's area, three Independent Power Producer (IPP) units were tripped on overfrequency at 1549. They were McMann Units 1 and 2 (90 MW) and NWE Unit 1 (70 MW). At approximately the same time, a 500-kV cable circuit between the Malaspina and Dunsmuir substations tripped on overvoltage (trip setting of 571.5 kV with a 250-millisecond delay).

BPA's SVC at Keeler tripped at 1548:58.251 when the cooling system tripped on undervoltage. The SVC controller was reset at 1549. The section lockout relays were reset at 1823 and disconnects closed at 1835. The Keeler SVC was back in service at 1945.

About one-and-a-half seconds after COI separation, the BCHA and MPC interconnections with BPA began large oscillations due to the NE/SE out-of-step separation.

The BCHA-BPA tie flows ramped from 2,300 MW to zero (export small amount to Canada) two minutes after the disturbance. At 1554, a 100-MW flow increase into BCHA was observed. After 1554, BCHA began exporting about 1,000 MW to the Northwest, following the loss of the BCHA-Alberta tie which was carrying 1,230 MW into Alberta at the time. The frequency stayed high in the Northern Island (about 60.4 Hz for 14 minutes, crossing 60 Hz after 17 minutes, dipping as low as 59.95 Hz, then rising to 60.04 Hz for the next 50 minutes). Despite having no direct schedules to California, BCHA cut schedules by 600 MW to reduce island frequency.

At 1628:50, the frequency dipped from 60 Hz to 59.9 momentarily, overshooting to 60.04 then recovering to 60 Hz.

NORTHERN ISLAND RESTORATION

The 230-kV Ross-Lexington line was restored at 1626; the Keeler-Allston 500-kV line was restored at 2057; the John Day-Marion and Marion-Lane 500-kV lines at 2250. The Big Eddy-Ostrander 500-kV line remained out of service overnight.

The Chief Joseph 230-kV powerhouse lines that were tripped by RAS action were energized at 1557.

McNary powerhouse was back on line in twenty minutes.

Restoration on the Oregon portion of the COI began at 1552 and was completed at 1657. The Grizzly terminal of the Round Butte line was opened at 1550. The John Day-Grizzly line and Grizzly north bus were returned to service at 1553. The Grizzly-Captain Jack line was energized briefly but was opened again due to high bus voltage. Many shunt reactors were then switched around the system to alleviate the high voltages. The John Day-Grizzly No. 2 line and the Grizzly south bus were returned to service at 1607. The Grizzly-Malin

No. 2 line was closed at 1608, energizing the Malin north bus. The Malin-Captain Jack No. 1 line and Captain Jack south bus were returned to service at 1611. The Malin No. 2 reactor would not stay closed and cycled at various times until the SCADA operator locked it out at 1632. At 1617, the Grizzly-Summer Lake line was energized and the line reactor placed in service. At 1628, the Captain Jack PCB 4986 was closed, energizing the PAC Meridian line. At 1643, the Summer Lake PCB 4958 was closed, energizing the PAC line to Midpoint, and immediately thereafter, the Midpoint PCB 544A was closed, returning the line to service. At 1648, the Malin PCB 4019 was closed, energizing the PAC 500/230-kV transformer, but it tripped free on phase discordance. At 1651, Malin energized to Summer Lake through PCB 4576. The PAC Summer Lake-Malin 500-kV line was returned to service by closing PCB 4576 at Malin and PCB 4957 at Summer Lake, at 1651 and 1652 respectively. At 1653, Malin PCB 4019 was closed by the local operator, energizing the PAC 500/230-kV transformer at Malin. At 1657, the Grizzly-Captain Jack 500-kV line was returned to service. This placed two lines in service from John Day to Grizzly and three lines from Grizzly to Malin and Captain Jack, ready to close to Round Mountain and Olinda.

At 1701, there were two complete bays at Grizzly. At 1702, the Captain Jack north bus was hot and two bays completely restored. At 1703, the ring bus at Summer Lake was closed up. At 1704, the Buckley-Grizzly 500-kV line was in service. At 1708, a third bay was complete at Grizzly. At 1707, the John Day bays were completely restored. At 1707, the first complete bay was restored at Malin. At 1712, Grizzly PCB 5040 was closed to Round Butte. At 1749, the Fort Rock series capacitors were bypassed.

At 1813, Captain Jack PCB 4980 was closed, energizing the line to Olinda. The closure of the Captain Jack-Olinda 500-kV line at 1818 completed the first tie to the Northern California Island. At 1829, Malin PCB 4064 was closed, energizing the Round Mountain No. 1 line. The remaining circuit breaker to complete the bay was closed at 1830. The Malin-Round Mountain No. 2 line remained out of service until 0708 on August 11 for insulator repairs. The last Captain Jack bay was restored at 1836.

The PDCI was restored to operation in 010 + 010 configuration at 1747, continuing through stages to full configuration of 311+311 at 1831.

BPA and PAC 115-kV and 230-kV circuits in Central Oregon were restored at 1628. PAC load in southern and central Oregon and northern California was restored by 1701.

In the following islands, restoration of customer service was impeded due to the large amount of thermal generation that tripped off line during the disturbance and the fact that it took almost an hour to restore system frequency to 60 Hz.

NORTHERN CALIFORNIA ISLAND DETAILS

This island was formed following out-of-step conditions and low voltages between Midway and Vincent two seconds after COI separation and following separation from Sierra Pacific at 1548.

At 1548:54.7 PAST, the Midway-Vincent No. 1 and No. 2 500-kV lines opened. Just prior to this action, the 500-kV bus voltage at Vincent was at 40 percent of normal. The Midway-Vincent No. 3 500-kV line tripped 65 milliseconds later. Line 2 tripped via channel C phase comparison relay, line 1 tripped via channel C out-of-step relay, and line 3 tripped via channel M out-of-step relay. Voltage was collapsing at about 7.5 kV/cycle just prior to these trips. These trips separated northern California from southern California.

During this same time frame, the Drum-Summit No. 1 and No. 2 115-kV lines tripped, separating PG&E from SPP.

The Olinda 500/230-kV transformer tripped on over voltage at 1549:47.366. The Tracy 500/230-kV transformer tripped by over voltage relay at 1549:51.899.

Frequency within the Northern California Island dropped to 58.3 Hz eight minutes into the disturbance. The underfrequency load shedding program within this island tripped all 10 blocks of load, representing approximately 50 percent of the northern California load. Numerous generating units tripped, including Diablo Canyon Units 1 and 2 (2,164 MW) at 1548.55.141 and 1548.55.405; Moss Landing Units 6 and 7 (1,474 MW) at 1551:47.420 and 1552:17.536; Morro Bay Units 1, 2, 3, and 4 (749 MW) at 1550; Contra Costa Units 6 and 7 (670 MW) at 1556; Hunters Point Unit 2 (10 MW) at 1550; Pit No. 1 Powerhouse Unit 1 at 1547, and Pit No. 7 Powerhouse Unit 7 (13 MW) at 1552. CDWR generation totaling 929 MW was lost at 1550, 1555 and 1557 due to the Table Mountain-Thermalito 230-kV 1, 2, and 3 lines relaying. The most likely cause was the No. 2-230 kV line sagging into a pine tree, flashing over and causing a fire. The fire spread to cause flashovers on the No. 1 and 3-230 kV lines. The Diablo Canyon units were tripped due to loss of synchronism, by directional instantaneous overcurrent relays looking into the unit step-up transformers. The units appeared to be stable with the remaining system until the Midway-Vincent lines relayed. Moss Landing Unit 7, Morro Bay Unit 1, and Contra Costa Units 6 and 7 relayed by loss of field. Moss Landing Unit 6 relayed due to volts/hertz overexcitation and regulator voltage balance. Morro Bay Unit 3 relayed due to undervoltage and Morro Bay Unit 4 by underfrequency. High voltage occurred on the 500-kV and 230-kV system; the North and South ties opened; and load was tripped. This high voltage, along with low frequency, contributed to the tripping of units. Volts/hertz relays primarily at Moss Landing and Contra Costa overrode other excitation protection and played a major role tripping the units.

In all, the Northern California Island lost 7,937 MW of generation and 11,602 MW of load (representing approximately 2.9 million customers) during the disturbance.

In addition to automatic load shedding in the island, the Fresno area manually reduced 80 MW of load to help recover system frequency at 1554. At 1556:03, the PG&E frequency dropped to 58.3 Hz due to the loss of generation in the island. The last two blocks (blocks 9 and 10) of underfrequency load were shed. An automatic protection scheme at Martin Substation operated to separate San Francisco from the Northern California Island when frequency declined to 58.3 Hz.

After the initial swing, when the frequency dropped to 58.5 Hz, frequency rapidly overshot to 60.7 Hz and fluctuated slightly above 60 Hz for over three minutes. Some of PG&E's load began automatically restoring after three minutes. (The PG&E load shedding program is designed to restore load in three to six minutes after frequency returns to near 60 Hz.) Over the next five minutes, as load was automatically restored and additional generation was tripped, frequency further declined to 58.3 Hz so that the load that had been automatically restored was tripped again. Frequency then returned to slightly above 59.0 Hz, where it began to stabilize. By 1600, 4,320 MW of load had been restored on the PG&E system. At 1607, frequency returned to 59.5 Hz where it stayed for approximately 75 minutes. At 1722, PG&E dispatchers manually shed load to bring the frequency back to normal. The low frequency in the Northern California Island prevented a parallel from being made with the Northern Island. From 1722 to 1732, PG&E manually shed 2,524 MW of load in Blocks 9 and 10. These blocks were restored by 2037.

Pit units were restored at 1641 and 1651. Hunters Point No. 2 was paralleled with the system at 1755.

At 1818, the COI was reestablished when the Captain Jack-Olinda line was closed. The Malin-Round Mountain No. 1 line was restored at 1829. The Malin-Round Mountain No. 2 line remained out of service because of damaged insulators. At 1843, Contra Costa Unit 6 was synchronized to the system.

Connections to southern California were restored at 1847 when the Midway-Vincent No. 1 and No. 3 lines were restored. The Midway-Vincent No. 2 line was closed at 1848.

The 115-kV ties to Sierra Pacific were restored at 1915. Morro Bay Unit 2 was paralleled at 2000.

By 2154, 91 percent of the PG&E customers were restored with all customers restored by 0100 on August 11. Morro Bay Units 1 and 3 were paralleled, respectively, at 2301 and 2318.

Moss Landing Unit 6 paralleled at 04:11 on August 11, while Unit 7 was paralleled at 1800 on August 11. Diablo Canyon Unit 2 was returned to service at 1431 on August 15, Unit 1 at 0410 on August 16.

Underfrequency detection on UPS at Western's control center in Folsom switched communication, computer and SCADA equipment from the AC power feed to DC power (batteries). At 1614, the UPS failed because of low battery voltage interrupting power to the communication, computer and SCADA equipment. The emergency generator was not designed to startup on underfrequency and it didn't switch on undervoltage due to high AC voltage in the island. Losing their SCADA at 1614 prevented Western from switching out 800 MVAR of 500 kV shunt capacitors at Olinda and Tracy, exacerbating high voltage in the island. At 1655, equipment was bypassed to restore AC power to critical equipment and at 1715, the UPS was restored.

SMUD lost 1,000 MW and 160,586 customers during the disturbance. Most of the load was automatically shed by underfrequency relay, but 384 MW was manually shed. Load restoration was completed at 2103.

SOUTHERN ISLAND DETAILS

This island consisted of southern California, Arizona, New Mexico, southern Nevada, Northern Baja California, and El Paso, Texas. This island was formed due to out-of-step conditions and low voltage between Midway and Vincent and out-of-step conditions on the Northeast/Southeast boundary. Generation totaling 13,497 MW was tripped, along with 15,820 MW of load (4.2 million customers).

By 1548:54.938, separation of the NE/SE boundary (TOT2) including the Hesperus-Waterflow 345-kV, Lost Canyon-Shiprock 230-kV, Glen Canyon-Sigurd 230-kV, Glade Tap-Durango 115-kV, Red Butte-Harry Allen 345-kV, and Pinto-Four Corners 345-kV lines, was complete, with all lines tripping due to out-of-step conditions. Frequency in this island dropped to approximately 58.5 Hz, triggering underfrequency load shedding. In this island, key generating units tripped, including Palo Verde No. 1 and No. 3 (2,493 MW), all three Navajo units 2,130 MW), Mohave Unit 2 (642 MW), Four Corners Unit 5 (762 MW), Cholla Unit 1 (107 MW), Coronado Unit 2 (357 MW), all Glen Canyon units (700 MW), Ormond Beach Unit 2 (689 MW), Encina Units 4 and 5 (323 MW), South Bay Unit 1 (92 MW), Etiwanda (318 MW) and 200 MW of Phoenix area generation.

At 1549, Intermountain Unit 1 (854 MW) tripped due to a sub-synchronous resonance protective relay operation (the SSR relay operated in response to commutation failures, not SSR). The Intermountain-Adelanto HVDC southern Transmission System (STS) ramped down by the appropriate amount in response to the unit trip. Several minutes later, Intermountain Unit 2 ramped down by approximately 200 MW due to boiler instability. Again the STS ramped down by the appropriate amount in response.

Units at Scattergood (at 1555) and Haynes (at 1549) in the LDWP control area were also tripped as well as many other smaller units at numerous locations across the Southern Island.

The three Navajo units tripped when a potential transformer on a series capacitor failed. The resulting fire and smoke caused a phase-to-phase fault on the Navajo-McCullough 500-kV line. Four seconds before this, the Navajo-Moenkopi line had tripped on out-of-step. Loss of these two lines left only the Navajo-Westwing line to carry power from the three Navajo units and it tripped on out-of-step, leaving the units isolated.

At 1549, the 345-kV Pinnacle Peak terminal of the Glen Canyon-Flagstaff-Pinnacle Peak 1 and 2 lines opened, initiating the RAS to trip four units at Glen Canyon, leaving three units generating 300 MW. The 345-kV voltage at Glen Canyon was 506 kV, tripping the east bus. Ten minutes later, the WAUC dispatch center at Montrose was ready to parallel at Flagstaff but the WALC dispatch center in Phoenix was unable to close the Pinnacle Peak 345/230-kV transformer breakers because the relay was still detecting an overexcitation condition. An operator had to be called out.

At 1617, the 230-kV Glen Canyon-Navajo, Kayenta-Navajo and Kayenta-Shiprock lines relayed, islanding the three units at Glen Canyon.

At 1621, the Glen Canyon-Navajo-Kayenta line was energized, but a phase shifter differential operation at Glen Canyon sent a transfer trip signal to Navajo.

At 1632, Glen Canyon unit 4 was put on line to provide station service. At 1633, the west bus relayed on overvoltage. Unit 6 was placed on-line at 1633. At 1640, the Glen Canyon-Navajo line was energized and the Glen Canyon east bus was energized one minute later. At 1644, the Flagstaff terminals of the Glen Canyon and Pinnacle Peak lines were opened in preparation for a return to service.

At 1750, the 345-kV Glen Canyon-Flagstaff No. 2 line was energized to Flagstaff and the Flagstaff bus was energized two minutes later. One minute later, the Glen Canyon-Flagstaff No. 1 line was in service, as well as the Flagstaff-Pinnacle Peak No. 1 345-kV line. The Flagstaff-Pinnacle Peak No. 2 line was in service at 1756.

All Glen Canyon units were returned to service by 1752.

At 1606:47, an additional 1,400 MW of manual load shedding was implemented by SCE at Valley 115-kV, Villa Park 66-kV and Chino 66-kV substations to help restore system frequency.

The frequency in the Southern Island remained below 60 Hz for over an hour. SRP manually shed 216 MW of load (after tripping 1,444 MW by underfrequency relaying).

As the frequency in the Southern Island began to recover and several key units in the Southern Island returned to service, system load restoration began at 1657. The frequency returned to normal at 1655 PAST.

At 1847, twenty-nine minutes after the Northern California Island synchronized to the Northern Island, Midway-Vincent 500-kV lines No. 1 and No. 3 were paralleled at Vincent, reestablishing the 500-kV tie between PG&E and SCE and reconnecting the Southern and Northern California Islands. At 1848, Midway-Vincent No. 2 was returned to service. Between 1850 and 1857, starting with the Four Corners-Pinto 345-kV line, the NE/SE lines were returned to service, completely restoring the WSCC bulk power transmission system.

By 2142, all the load shed in the Southern Island during the disturbance had been restored.

Major unit restoration began with Coronado Unit 2 at 1730, followed by Ormond Beach Unit 2 at 1915, Springerville Unit 1 at 2131, and Navajo Unit 1 at 2215. Palo Verde Unit 3 returned to service on August 11 at 1756 and Unit 1 was synchronized at 0454 on August 12. Navajo Unit 3 was the last of the major units to be restored, returning to service at 0608 on August 12.

ALBERTA ISLAND DETAILS

At 1554, approximately five minutes after the Northern Island separated from the rest of WSCC, the BCHA to Alberta interconnection (138-kV and 500-kV) tripped, separating the Alberta system from the Northern Island. At the time of the separation, the interconnection was supplying 1,230 MW to Alberta. The 138-kV tie tripped on transformer overcurrent and the parallel 500-kV tie tripped on undervoltage. Governor action in response to high frequency caused the loading on this interconnection to increase from 400 MW to 1,230 MW prior to the lines tripping. Frequency in the Alberta Island dipped to 59.0 Hz. In this island, 146 MW of generation was tripped and 968 MW of load was lost by underfrequency load shedding, affecting 192,000 customers. Alberta resynchronized with British Columbia at 1629. All load was restored by 1739.

Detailed data for each system are included in Appendices 1 through 4.

V. <u>SEQUENCE OF EVENTS</u>

See Appendix 5

VI. DISTURBANCE EVALUATION CHECKLIST

DISTURBANCE CATEGORY	DEFINITION	CONTRIBUTING FACTOR IN CAUSING THE DISTURBANCE, INCREASING ITS SEVERITY, OR HINDERING RESTORATION? (YES OR NO)	EXPLANATORY COMMENTS
1. Power System Facilities	The existence of sufficient physical facilities to provide a reliable bulk power supply system.	No	
2. Relaying Systems	Detection of bulk power supply parameters that are outside normal operating limits and activation of protection devices to prevent or limit damage to the system.	Yes	There were erroneous relay actions on exciters at McNary and the Merwin-St. Johns 115-kV line. The McNary units tripped at high reactive output levels.
3. System Monitoring, Operating, Control, and Communications Facilities	Ability of dispatch and control facilities to monitor and control operation of the bulk power supply system. Adequacy of communication facilities to provide information within and between control areas.	Yes	Several EMS/SCADA systems failed for a variety of reasons during the disturbance.
4. Operating Personnel Performance	Ability of system personnel to react properly to unanticipated circumstances which require prompt and decisive action.	Yes	One 500-kV line outage was known to PGE and another to PG&E by interutility data exchange, but the three 500-kV line outages experienced by BPA during the hour and a half prior to the disturbance were not reported to other WSCC members. NWPP procedures in place at the time did not identify the lines as “key” facilities for notification purposes. BPA operators did not understand the implications of a potential Keeler-Allston 500-kV line outage and take the necessary steps to mitigate its impact on system operation.
5. Operational Planning	Study of near term (daily, weekly, seasonal) operating conditions. Application of results to system operation.	Yes	BPA failed to identify the Keeler-Allston 500-kV line outage as a critical outage and develop a contingency plan. Reduced support from Lower Columbia plants was not accounted for in operating studies.
6. System Reserve and Generation Response	Ability of generation or load management equipment to maintain or restore system	Yes	Governor action in Alberta overloaded and tripped BCHA/TAUC ties. There was uncontrolled loss of generation in the underfrequency islands.

DISTURBANCE CATEGORY	DEFINITION	CONTRIBUTING FACTOR IN CAUSING THE DISTURBANCE, INCREASING ITS SEVERITY, OR HINDERING RESTORATION? (YES OR NO)	EXPLANATORY COMMENTS
	frequency and tie line flows to acceptable levels following system disturbance.		
7. Preventive Maintenance	A program of routine inspections and tests to detect and correct potential equipment failures.	Yes	Inadequate right-of-way maintenance (tree trimming) was a significant factor in this disturbance. Previously identified danger trees had not been trimmed or removed.
8. Load Relief	The intentional disconnection of customer load in a planned and systematic manner to restore the balance between available power supply and demand.	Yes	Coordination of underfrequency load shedding was inadequate.
9. Restoration	Orderly and effective procedures to quickly reestablish customer service and return the bulk power supply system to a reliable condition.	Yes	Automatic load restoration delayed frequency recovery in the Northern California Island. Southern Island manual load restoration was not effectively coordinated. Cutting complex schedules is difficult and time consuming, delaying frequency recovery.
10. Special Protection Systems	Use of relays to initiate controlled separation and generator tripping to prevent a widespread blackout.	Yes	The NE/SE Separation Scheme was not in service. That may have caused additional transmission and unit tripping.
11. System Planning	Comprehensive planning work utilizing appropriate planning criteria to provide a reliable bulk power supply system.	Yes	Generator reactive capabilities used in planning studies were higher than the actual capabilities for key units along the lower portion of the Columbia River. PSS was represented in studies at unrealistically high in-service levels.
12. Other	Any other factor not listed above which was significant in causing the disturbance, making the disturbance more severe or adversely affecting restoration.	Yes	Generator underfrequency protection is not adequately coordinated with other UF programs.

VII. EXHIBITS

Summary of Plots and Figures: Very good information was obtained from the Portable Power System Monitor (PPSM) at Dittmer and other locations on the power system to help reconstruct the events of the disturbance. A selection of plots is provided showing some of the key events described. PPSM scaling may be in error on some plots. Subtract 5 seconds from time scale to match sequence of events timing.

Exhibit 1 Response to loss of Keeler-Allston (Dittmer PPSM)
Shown in **Exhibit 1A** are step changes in line flows in the northwest resulting from outage of the Keeler-Allston line. **Exhibit 1B** includes voltage at Slatt (near McNary) showing reduction in voltage. Also shown is response on COI as indicated by PG&E Olinda MW. Oscillation is lightly damped.

Exhibit 2 Response to loss of Ross-Lexington (Dittmer PPSM)
Exhibits 2A-2F show the Northwest response on selected lines and generators to the Ross-Lexington trip. **Exhibit 2D** illustrates the reduction in power at McNary resulting from sequential tripping of all 13 units. All figures show the system oscillation of 0.224 Hz which began at the time of loss of Ross-Lexington and initial tripping of McNary units and becomes more negatively damped (unstable) as additional units are tripped. **Exhibit 2A** shows that voltage at Malin drops lower on successive swings until the COI opens. **Exhibit 2F** shows a detailed plot of the initial response following loss of the Ross-Lexington line before the system oscillation began to grow.

Exhibit 3 DC Schedule-Actual (Dittmer PPSM)
This figure shows the response of the PDCI at the time of COI separation. Dynamic swings on the PDCI resulted in initiating PDCI remedial actions. Also initiated is the PDCI algorithm to automatically change schedules to actuals intended to minimize impact of a monopole outage on the COI initiated by swings on the PDCI.

Exhibit 4 COI and Midway-Vincent Separations (PG&E DSM)
Shown are the responses for the North Tie (Malin-Round Mountain 1 and 2) and the South Tie (Midway-Vincent). Outage of the South Tie occurs very soon after loss of the North Tie (approximately 2 seconds) as a power reversal occurs to support the northern California area.

Exhibit 5 Table Mountain response at time of separation (PG&E DSM) **Exhibit 5A** shows Table Mountain voltage and frequency. **Exhibit 5B** shows MW and MVAR flows at Table Mountain. **Exhibit 5C** shows a detailed plot of the system oscillation.

Exhibit 6 - McNary MVAR (USCE McNary recorder)
This Exhibit shows the initial plant loading of 260 MVAR followed by an increase to over 360 MVAR after loss of the Keeler-Allston and Ross-Lexington lines.

Exhibit 7 - SCE Island frequency (SCE recording)
This figure shows the frequency decline in the Southern Island following the disturbance.

Exhibit 8 - Diagram with northwest sequence of events.

Exhibit 9 - Map showing islands formed and sequence of significant events leading to separation.

Exhibit 10 - BCHA-Alberta power transfer, frequency plots for Alberta, and BPA frequency/time error plots.

Exhibit 11 - PG&E frequency plot, indicating unit tripping and load shedding times.

Exhibit 12 - WSCC Interchange Diagram and Supplemental Line Flow Report; Hour Before Disturbance

Appendix 1

Customers Affected and Load Lost

Appendix 2

Generation Lost

Appendix 3

Transmission Lines Tripped

Appendix 4

Abnormal Conditions

Appendix 5

Sequence of Events

Exhibit 9

Significant Events Leading to System Separation

Map Showing Sequence of System Separation

Exhibit 10

BCHA-Alberta Power Transfer

Frequency Plots for Alberta

BPA Frequency/Time Error Plots