WESTERN INTERCONNECTION (WSCC) SYSTEM DISTURBANCES — July 2 & 3, 1996

Detailed Description

A disturbance occurred at 1424:37 MDT on July 2, 1996 that ultimately resulted in the Western Systems Coordinating Council (WSCC) system separating into five islands (Figure 1) and in electric service interruptions to over two million customers. Electric service was restored to most customers within 30 minutes, except on the Idaho Power Company (IPC) system, a portion of the Public Service Company 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 1424:37.18 MDT on the 345 kV Jim Bridger – Kinport line (Figures 1 & 2). The fault occurred 97 miles east of Kinport and was caused by a flashover (arc) when the conductor sagged close to a tree. System protection removed the line from service clearing the fault in three cycles.

System protection opened the 345 kV Jim Bridger – Goshen line twenty milliseconds (ms) later due to misoperation of the ground element in a relay at Bridger. The relay was later 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 removed two generating units from service (Nos. 2 & 4) at Bridger (generating 1,040 MW total), bypassed the series capacitor at Burns and segment No.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 this Bridger generation with generation from throughout the entire Western Interconnection.

The next recorded event (1424:38.99) was system protection opening the 230 kV Round Up – LaGrande line due to misoperation of a zone 3 relay at Round Up. Voltage at the LaGrande 230 kV bus dropped from 220 kV, following the removal from service of the Bridger units, to 210 kV after the LaGrande line opened. Investigation by Bonneville Power Administration (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 corrosion 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 was replaced. This relay was last tested and calibrated on March 9, 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 supervisory control and data acquisition (SCADA) system sounded alarms that the voltage at BPA’s Anaconda Substation dropped to 219 kV and the Rattle Snake voltage was 224 kV. At 1424:47, 230 kV shunt capacitors at Anaconda were energized via a voltage control relay. In eastern Idaho, BPA’s Lost River 69 kV sounded an alarm at 63 kV, Heyburn sounded an alarm nine seconds later at 134 kV, and three seconds later Spar Canyon sounded an alarm at 217 kV. In Eastern Oregon, McNary sounded an alarm at 238 kV, and at 1424:45 LaPine sounded an alarm at 114 kV and Harney at 109 kV. In southern Oregon, Warner reported high voltage (242 kV) at 1424:59.
The redistribution of flows that followed resulted in 300 MW of increased loading on the 230 kV lines from Oregon and Washington to Idaho. Correspondingly, flows on the four 230 kV Brownlee – Boise Bench lines into the Boise area increased to 1,320 MVA (900 amps at about 212 kV). Flows on the 230 kV Antelope – Mill Creek line between Montana and Idaho measured at the Mill Creek end, increased to 377 MVA (900 amps at about 220 kV). In addition, the flow on the 500 kV Midpoint – Summer Lake line increased by 400 MW into Idaho.

The 345 kV Humboldt – Midpoint line between northern Nevada and southern Idaho picked up 72 MW of the dropped Bridger generation (import into SPP 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 (Pacific Gas & Electric Company) ties, 4 MW via the east SPP – PACE (PacifiCorp East) tie and 4 MW via the south SPP – SCE (Southern California Edison Company) ties. The remaining 12 MW came from Sierra Pacific’s frequency response characteristic.

At about 1424:51, system protection removed a C.J. Strike unit (26 MW) from service due to field excitation over current. At about 1425:01 a second 26 MW unit was removed from service at C.J. Strike for the same reason.

The 230 kV Mill Creek – Antelope line opened at 1425:01.052. The line was removed from service by a zone 3 impedance relay (timed out) at Mill Creek due to a high load condition input to the three-phase distance characteristic of the relay.

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

Following the opening of the Mill Creek – Antelope line, about 23 seconds after the Bridger units were removed from service, 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 (Figure 3).

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

The low voltage enable the Celilo HVDC RAS shunt capacitor bank insertion at Malin armed within 0.5 seconds from the Mill Creek – Antelope line opening.

At about 1425:02, the third unit at C.J. Strike (26 MW) also was removed from service due to field excitation over current. In addition, two McNary units were removed from service (130 MW) at 1425:03.2 due to suspected loss of excitation. At 1425:05.5, another 60 MW unit at McNary was removed for the same reasons. At the same time as, or immediately after system separation, two more McNary units were removed (120 MW).

The four 230 kV Brownlee – Boise Bench lines were opened by impedance relays over the period from 1425:04.404 to 1425:05.237. The first two lines (Nos.3 & 1) were removed from service by reverse zone 3 impedance relays at Boise Bench. The third line (No.2) was opened by a zone 2 relay at Brownlee, and the last line (No.4) was opened by a permissive over-reach scheme at both ends. The 230 kV Oxbow – Lolo and Hells Canyon – Walla Walla lines were removed from service 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 500 kV Malin shunt capacitor group 3 was switched into service via automatic voltage control. At 1425:05.700, the 115 kV Harney – Redmond terminal was removed from service and the Fort Rock Series Capacitors inserted on all three lines south of Grizzly one to three cycles later.

At Celilo, collapsing voltages affected the Pacific DC Intertie (PDCI). In an attempt to maintain electricity flows, the dc line controls automatically raised the line current. Once the maximum limit of 3,100 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 a 10-second sliding-window algorithm. At 1425:06.72, Celilo detected an ac overload condition and the 20-minute electricity loss integrated algorithm initiated just prior to the Malin – Round Mountain line openings.

In the five-second period prior to the California – Oregon Intertie separation, reactive flows increased from 400 to 2,400 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 500 kV Malin – Round Mountain No.2 line opened at Malin at 1425:06.787. opening was followed six milliseconds later by the opening of the Malin – Round Mountain No.1 line at Malin. These lines were opened by an under-impedance switch into fault logic. The 500 kV Captain Jack – Olinda line was opened 87 ms later, by positive sequence relay action at 1425:06.880.

Loss of the COI activated a RAS, 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 one to three cycles later.

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

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

Following the Captain Jack – Olinda line opening by system protection, the low voltage problem on the COI became a high voltage problem at Malin, and the disturbance changed to transient stability except in Idaho, where the voltage collapsed. The ensuing high voltage resulted in an arrester failure at Malin on the PacifiCorp West Summer Lake line reactor, and at 1425:07.217, system protection opened the 500 kV Summer Lake – Malin line. This action was followed by the opening of 500 kV Captain Jack – Meridian line at 1425:07.330 and the 500 kV Grizzly – Summer Lake line at 1425:07.344. The Captain Jack 500 kV circuit breaker (Olinda line) cleared the adjoining positions due to breaker failure in the open position. The Malin 500 kV shunt capacitors opened on over current after four seconds. Malin circuit breaker (for shunt capacitor group four) began arcing around the breaker housing, causing the breaker to fail clearing the Malin north bus. Also, on shunt capacitor group 3, six capacitor cells, 37 fuses, and six fuse holders failed.

As an electricity surge started through northern Nevada toward southern Idaho, the voltage dropped rapidly on the north 345 kV tie. About 168 MW of northern Nevada demand was shed during the transient low voltage (believed to be the result of motor contactors dropping out, etc.).
In northern Wyoming, the 161 kV Yellowtail – Rimrock and the 230 kV Yellowtail – Billings and Yellowtail –
Crossover lines were opened by out-of-step relay action between 1425:07.207 to about 1425:07.395, separating
Wyoming from Montana.

The above line openings 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 WSCC.

The 345 kV Borah – Bridger line opened at 1425:07.329 separating the remaining Bridger generation from
Idaho. At 1425:07.67, when frequency dropped below 59.3 Hz for 0.1 second, Sierra Pacific’s first step of
under frequency load shedding operated, dropping 160 MW of firm demand.

The first line opening between the Idaho – Utah regions occurred at 1425:07.760 when the 345 kV Borah – Ben
Lomond line opened at Borah. Although this line normally would be transfer opened by the Treasureton out-of-
step scheme, it actually opned 70 ms before that scheme activated at 1425:07.790. The Treasureton scheme
opened the 230 kV Treasureton – Brady line, the 138 kV Wheelon – American Falls line, the three 138 kV
Treasureton – Grace lines, separated the 345 and 230 kV Jim Bridger switchyards (the generators are tied to the
345 kV bus) and shed PacifiCorp’s Monsanto demand in southeastern Idaho. These actions separated the
PacifiCorp system in southeastern Idaho, leaving its demands 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, the Jim Bridger unit No.3, now isolated from any significant
demand, was removed from service.

The frequency in northern Nevada (still part of the southern island) dropped an additional 0.1 Hz to just below
59.1 Hz. This drop resulted in activation of Sierra Pacific’s second step of under frequency load shedding, and
dropping 90 MW of additional firm demand. 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 demand was now being supplied 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 opening (a shift of 670 MW). This shift in load flow
was supplied by Sierra Pacific’s other ties. These ties supplied 165 MW of generation, 250 MW of under
frequency load shedding, 168 MW of load shed due to transient low voltage, and 87 MW in SPP’s frequency
and electricity surge response (of which 80 MW was an increase in generator output).

At 1425:08.138, the 345 kV Valmy – Coyote Creek line in northern Nevada opened. In northern Nevada, the
230 kV Ft. Churchill – Austin line was removed from service at 1425:08.150. This line opening made the final
separation between southern Idaho and Utah and separated northern Nevada’s bulk electric system from the
Utah system.
Sequence of System Separations

Islands Formed -- July 2, 1996

Figure 1
In southern Idaho, the Idaho Power Company system continued to break up and shed demand due to low voltage. The 345 kV Kinport – Midpoint line opened at 1425:08.156. At 1425:08.167, the Borah – Adelaide-Midpoint No.1 line opened, followed by the No.2 line at 1425:08.182. These actions effectively separated the backbone transmission system between eastern and western Idaho. About 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 SPP’s ties to California via the weak 120 kV California – Summit, 120 kV North Truckee – Summit, and 60 kV Truckee – Summit ties. At about 1425:08.300, the 120 kV ties were opened by out-of-step relays. The 60 kV tie also opened. At 1425:09.255, the 345 kV Humboldt – Midpoint line was removed from service at Midpoint due to instability. An additional 55 MW of transmission dependent demand was shed as part of SPP’s remedial action scheme for loss of the Humboldt – Midpoint line.

When the Humboldt – Midpoint line opened, the Idaho (Island 4) and northern Nevada (Island 5) islands were formed, leaving the Western Interconnection separated into four islands. At this point, the northern Nevada island was in an “high frequency” condition.

The Rocky Mountain area was still connected with Arizona/California. The entire southern island was about 5,000 MW deficient in generating resources. The frequency in this island declined to 59.2 Hz at 1425:100. Under frequency load shedding of about 3,000 MW occurred in Utah and Colorado. The resultant excess generation in the Rocky Mountain area tried to flow to the Arizona/California area, which was still deficient in generation. This surge in generation flow caused an out-of-step line separation across the TOT 2 Path, (Utah/Colorado, Arizona/New Mexico/Nevada interface). This out-of-step electricity surge (at 1425:11) opened the 345 kV Waterflow – Hesperus, Pinto – Four Corners, and Red Butte – Harry Allen lines, the 230 kV Lost Canyon – Curecanti and Sigurd – Glen Canyon lines, and the 115 kV Durango – Glade Tap line. Sierra Pacific’s 55 kV ties to Southern California Edison Company opened 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). Formation of all five islands now was complete.

**Summary of Demand Shed Within Islands**

**Island 1**

Within Island 1, frequency dropped to 59.1 Hz and under frequency load shedding occurred with Pacific Gas & Electric Company shedding 2,400 MW and Southern California Edison Company shedding 505 MW. A total of about 4,484 MW were shed affecting about 1,183,000 customers. Over 90% of the demand was restored within 30 minutes and all demand was restored within 21/2 hours.

**Island 2**

Another major island consisted of Washington, Oregon, Montana, British Columbia, and Alberta. About 3,900 MW of generation was automatically removed from service in this island by over frequency relays and by the remedial action scheme that monitors the California-Oregon Intertie. Impact on customers was minimal. An estimated 7,452 customers (100 MW) were interrupted over a period ranging from minutes to about one hour. About 7 MW of firm BPA demand and 3 MW of an industrial customers demand at the Cowlitz County PUD No.1 was shed due to low voltage.
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<th>Time</th>
<th>Unit/Line</th>
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<td>Brady-Treasureton remedial action scheme takes affect</td>
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<td>29</td>
<td>1425:37.185</td>
<td>Silver Peak-Control line tripped</td>
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Figure 3
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 demand was shed, mostly due to under frequency, along with over voltage 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 removed from service in the island for various reasons. The frequency remained high for about six minutes. With demand restoration, generation ramping down, and 2,000 MW of generation removed from service, the frequency again fell as low as 59.3 Hz. This drop resulted in under frequency load shedding followed by additional demand being manually shed in the island in an effort to restore proper frequency. The frequency remained high for about six minutes. With demand restoration, generation ramping down, and 2,000 MW of generation removed from service, the frequency again fell as low as 59.3 Hz. This drop resulted in under frequency load shedding followed by additional demand being manually shed in the island in an effort to restore proper frequency. The under frequency load shedding operated as designed and frequency recovered to 59.35. At this time, various generator under frequency 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, ramping the Stegall (11 minutes after islanding) and Virginia Smith HVDC (22 minutes after standing islanding) ties in the wrong direction for one to three minutes exacerbated the island frequency condition. About 100 MW was being exported to rather than 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 demand and generation was interrupted. A small portion of BPA customer demand at LaGrande remained connected to six western Idaho generators that remained on line at Hells Canyon, Oxbow, and Brownlee. A portion of PacifiCorp’s demand in southeastern Idaho remained in this island, but did not have electric service. About 3,368 MW of demand (425,000 customers) was interrupted. Idaho Power Company lost all customer demand in Idaho and radially served demand located in northern Nevada as well as a small part of eastern Oregon.

BPA customer demand in the LaGrande, Baker, John Day, and Bums was in a sub-island carried by IPC’s Hells Canyon complex generation. Following the Roundup – LaGrande and Mill Creek – Antelope line openings, 40 MW of demand was dropped due to extremely low voltage at LaGrande. One customer lost 14 distribution arresters in the LaGrande and Baker areas due to high voltage. This same customer removed from service its West John Day and Bums (Hines) demands via over voltage protection. The Baker demand was shed at 1455 and stayed out till 1647.

Island 5

A fifth island was formed in northern Nevada at 1425:09.255. Before electric service restoration could be completed, SPP demand dropped 550 MW. Of this amount, about 418 MW was shed during the transient frequency and voltage dips, which coincided with an electricity surge going through northern Nevada toward southern Idaho. The 418 MW loss occurred as the first island began to separate from the rest of theWSCC at 1425:07.395. Of the 418 MW, 250 MW was comprised of under frequency load shedding; the remaining 168 MW was uncontrolled loss of voltage sensitive demands. Voltage sensitive demands consist primarily of motor load, which is shed when motor contactors open during severe low voltage. Although the loss of 168 MW of customer demand was scattered throughout northern Nevada, 103 MW was shed in the system north of Valmy. At 1425:09.255, the 345 kV Humboldt – Midpoint tie opened when transmission between southern Idaho and northern Nevada became unstable. This instability initiated a RAS that successfully shed 55 MW of transmission dependent demand. Frequency jumped to 60.75 Hz in northern Nevada once the island formed. At 1427:11, 17 MW were shed on the 120 kV system south of Anaconda Moly due to over voltage. At 1430:26, the 230 kV Austin-Frontier line opened at the Austin end due to over voltage and sent a signal to Gonder to open the Gonder end of the 230 kV Gonder – Machheck line. This action removed from service 20 MW of demand from the 230 kV system between Fort Churchill and Gonder. Gonder demands were still being served via Utah. An additional 40 MW was shed on under frequency load shedding during the restoration sequence.
July 3 Disturbance

The following day, July 3, 1996, at 2:03 p.m., a similar chain of events began. The 345 kV Jim Bridger – Kinport line again flashed (arced) to a tree and was automatically disconnected by protective devices, clearing the short circuit. At nearly the same time, the 345 kV Jim Bridger – Goshen 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 activated 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 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 generating unit No.5 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 supplied by their units. As a precautionary measure to avoid possible unit shedding 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 the load shed. It is not clear whether the IPC system operators would have had to resort to shedding firm demand had the Brownlee plant continued to contribute full reactive support.

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

Conclusions and Recommendations

Due to the significant nature of this system-wide disturbance, 24 conclusions and 44 recommendations were made. They are all in the final WSCC report dated September 19, 1996. The Disturbance Analysis Working Group selected four key conclusions and associated recommendations to give the reader a sample of the problems identified.

Conclusion:

1. The simultaneous combination of operating conditions on July 2, characterized by record peak summer demands in Idaho and Utah, maximum water flow conditions in the Pacific Northwest, high north-to-south electricity transfers on the California-Oregon ac and dc interties, transfers from the Northwest to Idaho and Utah, high volumes of electricity transfers from Canada to the Northwest, and high amounts of thermal generation in Wyoming and Utah were not anticipated or studied. The speed of the collapse seen July 2 was not observed in this region and was not anticipated in studies.

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 345 kV Jim Bridger lines, should not have resulted in the system separations and loss of demand experienced on July 2, 1996.

Recommendation:

Idaho Power Company, PacifiCorp, Bonneville Power Administration, and other Northwest area entities shall reduce scheduled electricity transfers at 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.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

Conclusion:

2. WSCC and its member systems conduct hundreds of studies each year to access 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 Planning Coordination Committee/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.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 4 — System Coordination, D. System Protection Coordination
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

Conclusion:

12. The voltage collapse in the Idaho Power Company system on July 2 resulted in a black out of the IPC system. On July 3, IPC dispatchers demonstrated the viability of load shedding in preventing voltage collapse.

Recommendation:

IPC shall consider implementing automatic under voltage 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 under voltage load shedding programs, as appropriate. WSCC members shall report to WSCC staff the measures implemented.

Refer to: NERC Operating Policy 5 — Emergency Operations, D. Separation from the Interconnection
NERC Operating Policy 6 — Operations Planning, C. Automatic Load Shedding
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, B. Demand-Side Resources
Conclusion:

21. 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 currently accomplished by individual control areas.

Recommendation:

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.

Refer to:
- NERC Operating Policy 2 — Transmission, A. Transmission Operations
- NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
- NERC Operating Policy 4 — System Coordination, A. Monitoring System Conditions
- NERC Operating Policy 4 — System Coordination, B. Coordination With Other Systems — Normal Operations
- NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
- NERC Operating Policy 6 — Operations Planning, C. Automatic Load Shedding
- NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, B. Security
- NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

Anyone interested in obtaining a hard copy of the WSCC disturbance report is asked to submit in writing a request to the WECC Technical Staff at the Western Electricity Coordinating Council (formerly the Western Systems Coordinating Council) office.
BIG RIVERS ELECTRIC CORPORATION DISTURBANCE —
AUGUST 7, 1996

Summary

Big Rivers Electric Corporation (BREC) experienced a system disturbance that islanded part of its system on Wednesday, August 7, 1996. This disturbance resulted in the loss of a total of 347 MW of demand, consisting of 259 MW of BREC demand and 88 MW of load of Henderson Municipal Power & Light (HMPL) demand, which is within the BREC control area. System protection removed some 1,180 MW of generation within the BREC control area within the island. The outage occurred during switching to alleviate overloads on BREC ties to Southern Indiana Gas & Electric Company (SIGE) and Hoosier Energy Rural Electric Cooperative, Inc. (HE).

As a result of this outage, BREC has taken a number of internal corrective actions, and is pursuing improvements to system security in the future through the participation in the development of the Midwest Independent System Operator (ISO).

ECAR also will pursue improvements in communicating study results to system operation personnel, reemphasis on the importance of proper right-of-way and protection equipment maintenance, and improvements in the MAIN-ECAR-TVA (MET) line loading relief procedure.

Pre-Event Conditions

Network electricity flows through the BREC system were unusual on August 7 in that they exhibited a south-to-north bias, with the BREC southern ties having lower than normal flows and the northern ties higher than normal. Typical flow bias is north-to-south during the summer.

Key Events

On the morning of August 7, the BREC 161 kV transmission interconnection between its Coleman station and Hoosier Energy at SIGE’s Newtonville station, and the SIGE 161/138 kV tie transformer at Newtonville were heavily loaded.

Over the course of the morning, loadings on those system elements drifted upward, eventually exceeding their normal thermal ratings. At 1030 CDT, BREC redispached internal generation to alleviate the loadings, achieving a 4% reduction on the 161 kV Coleman – Newtonville tie flow. However, across the next hourly ramping period (1050 to 1110 hours), network south-to-north flows increased by about 40 MW, eradicating the line loading relief previously achieved by the redispatch of generation. This change in flows was later attributed to an electricity transaction accepted by the BREC system operator of a 50 MW purchase from the south, coupled with a 50 MW sale to the north. This transaction resulted in a 30 MW increase in loading on the already-overloaded 161 kV Coleman – Newtonville tie to HE.
At 1105 CDT, SIGE advised BREC of its intent to open the low-side breaker on the 161/138 kV Newtonville tie transformer to protect it from damage. The BREC system operator requested five minutes to alleviate the loadings and began an immediate significant reduction in generation. Before the effects of the generation reduction could be realized, the BREC system operator opened the 345 kV Wilson – Coleman line (1109) to divert flows from the Coleman area. This operator action was premature, but the operator believed that it would alleviate the overload problem. The opening of the 345 kV Wilson – Coleman line resulted in an overload of the Reid – Davies County 161 kV line, causing it to sag into a tree about four (4) minutes after the 345 kV line was opened. The Reid – Davies County line outage caused subsequent overloads on two additional circuits, the 161 kV Hopkins County – Barkley tie line to TVA and the 161/138 kV tie transformer to SIGE at BREC’s Henderson County station. System protection opened both circuits, effectively isolating or islanding a major segment of the BREC system.

The islanded section of the system suffered severe voltage and frequency swings and system protection removed all but one generator serving 12 MW of local demand in the HMPL system, resulting in loss of all 347 MW of other demand in the islanded system.
System Restoration

All BREC customers had electric service restored (47 MW) in about five minutes except for an aluminum smelter. Voltage and reactive support concerns for this industrial customer (212 MW) delayed its restoration until adequate local generation could be returned to service. The HMPL customers were returned to service in 10 to 12 minutes. All circuits opened or removed from service during the outage were returned to service by 1131, and an additional 69 kV tie that had been operated open prior to the incident was closed for additional voltage support. Throughout the incident, all protective relays operated as expected.

Generation Outages

The total amount of generation removed from service during the disturbance was 1,180 M. It comprised: Green units Nos.1 & 2 (445 MW), HMPL Station 2, units Nos.1 & 2 (Operated by BREC, 308 MW), Reid unit No.1 (52 MW), and Wilson unit No.1 (375 MW)

BREC’s Coleman units 1, 2, & 3 (440 MW) was not part of the island and remained on-line through the event. Also, HMPL Station 1 unit No.6, which is connected to the HMPL 69 kV system within the islanded area, remained on line through the incident carrying about 12 MW of local HMPL demand. BREC’s Reid Combustion Turbine was off-line during the outage.

Big Rivers Corrective Actions

BREC cited that following corrective actions in their internal outage report to prevent similar future occurrences:

1. BREC will participate in the organization and operation of the Midwest ISO, which will be empowered to oversee flows of neighboring utilities and take an area approach to dealing with overloads.

Refer to: NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy
2. BREC will be completing a new 161 kV interconnection with Kentucky Utilities by the end of 1996. This tie line offers significant benefits in strengthening BREC’s interconnection capacity.

Refer to: NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy

3. BREC’s management issued operational orders prohibiting the opening of its internal transmission lines and the jeopardizing customer service reliability in support of electricity exports.

Refer to: NERC Operating Policy 3 — Interchange, A. Interchange

4. BREC will increase its right-of-way clearing maintenance efforts in areas near creeks and streams where its current four-year maintenance cycle is insufficient to keep fast growing trees from endangering line operation.

ECAR MSDTF Findings and Recommendations

The ECAR Major System Disturbance Task Force determined:

1. Finding: The main cause of the outage was operator error.
   - Failure to follow established operating procedure, i.e., reduction of generation output to alleviate overloads
   - Failure to analyze system impacts of buy/sell (south-to-north) transactions
   - Failure to use all tools at the system operator’s disposal to analyze situation

Recommendation: Improve operator training in these areas.

Refer to: NERC Operating Policy 8 — Operating Personnel and Training, C. Training

2. Finding: All relay operations were correct and appropriate.

Recommendation: ECAR should emphasize among its members the importance of good relay coordination and maintenance.

Refer to: NERC Operating Policy 4 — System Coordination, B. Coordination With Other Systems — Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

3. Finding: Inadequate tree trimming was a factor in precipitating this outage.

Recommendation: ECAR should emphasize among its members the importance of good relay coordination and maintenance.

Refer to: NERC Operating Policy 4 — System Coordination, B. Coordination With Other Systems — Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems
4. Finding: The MAIN-ECAR-TVA (MET) Line Loading Relief Procedure may have been helpful in managing these overloads.

Heavy line loading problems caused by north-to-south electricity transfers in the BREC area during the summer of 1993 resulted in the establishment of the MET Line Loading Relief Procedure. That procedure specifically addresses north-to-south overload problems in MAIN and southern ECAR, and was incorporated in the ECAR Security Process, administered by American Electric Power (AEP) as the Security Coordinator.

Recommendations:
- Review training of ECAR system operations personnel on use of the MET procedure
- Improve the MET procedure to make it more readily usable with the Interregional Security Network and security process

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 8 — Operating Personnel and Training, C. Training
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

5. Finding: Outage resembles a scenario analyzed in the January 1996 Assessment of ECAR Transmission Systems Conformance to ECAR Document No. 1: System Collapse in the BREC Area for Loss of the Wilson-Coleman 345 kV Circuit, followed by a loss of the Reid-Davies County 161 kV circuit during heavy BREC exports to Indiana. The BREC System Operator was not aware of those ECAR study results.

Recommendation: ECAR should improve dissemination of Regional and Interregional study result to system operations personnel.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Operating Policy 8 — Operating Personnel and Training, C. Training
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

For additional information on this event, please contact the East Central Area Reliability Agreement (ECAR) office.
WESTERN INTERCONNECTION (WSCC) SYSTEM DISTURBANCE — AUGUST 10, 1996

Summary

A major disturbance occurred in the Western Interconnection (Western Systems Coordinating Council, WSCC) at 1548 PDT, August 10, 1996 resulting in the Interconnection separating into four electrical islands (Figure 1). Conditions prior to the disturbance were marked by high summer temperatures (near or above 100 degrees Fahrenheit) 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 California–Oregon Intertie (COI) North to South electricity flow was within parameters established by recent studies initiated as a result of the July 2-3, 1996 disturbance (see disturbance No.3, Page 22). The flow on the COI was about 4,350 MW and the flow on the Pacific DC Intertie (PDCI) was 2,848 MW.

Operations Prior to Disturbance

At 1401 PDT, system protection opened the 500 kV Big Eddy – Ostrander line when it flashed (arced) and grounded to a tree. The Portland General Electric Company (PGE) McLoughlin terminal of the 230 kV Big Eddy – McLoughlin line opened and reclosed for this fault, which was close to the Ostrander terminal. The Big Eddy – Ostrander line was tested and returned to service at 1403. At 1406 (Figure 2), “A” phase opened on the Big Eddy – Ostrander line, reclosed, then all three phases opened and remained out of service. PGE’s Big Eddy – McLoughlin again opened and reclosed. Bonneville Power Administration (BPA) dispatchers began to receive low voltage alarms, which were corrected by switching out of service shunt reactors and switching into service shunt capacitors.

At 1452:37, the 500 kV John Day – Marion line opened and locked out when the line flashed and grounded to a tree near Marion. Because a Marion 500 kV circuit breaker was out of service, the 500 kV Marion – Lane line was forced out of service. At 1456 the John Day – Marion line opened when it was tested.

At 1542:37, 50 minutes after the John Day – Marion line faulted, the 500 kV Keeler – Allston line opened after flashing to a tree near Keeler. At this point, five 500 kV line segments were out of service, removing several hundred MVAr of reactive support from the system while simultaneously increasing the reactive requirement as other lines picked up the electricity flow previously carried by the out of service lines. BPA dispatchers requested maximum reactive power boost from John Day and The Dalles (both hydro plants) within one minute of the Keeler – Allston opening. Prior to the Keeler – Allston trip, the 13 McNary hydro 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 opened on test at 1544. The John Day substation was receiving 408 MVAr from the John Day powerhouse and Big Eddy was receiving 77 MVAr from The Dalles. The reactive output of the McNary generating units was boosted from 260 to 475 MVAr (which was over their maximum sustained MVAr output at that power level) immediately following the Keeler – Allston opening.

At 1547:36, the 230 kV Ross – Lexington line opened when it flashed to a tree. This relay operation resulted in system protection also removing PacifiCorp’s Swift generating unit (207 MW). The reactive output of the McNary units was boosted to 480 MVAr, then to 494 MVAr. The units held at this level for a short time, then system protection began removing them from service. Between 1547:40 and 1549 all 13 units were removed from service as a result of erroneous operations of a phase unbalance relay in the generator exciters. Following
the loss of the McNary units, the Boardman Plant was supplying 275 MVAr in response to collapsing voltage while in constant excitation mode.

**Power Oscillations**

Following the removal from service of the McNary units, a mild oscillation began on the transmission system. Grand Coulee, Chief Joseph, and John Day hydro generation began to increase generation to make up the difference. When McNary generation dropped to about 350 MW, the oscillation became negatively damped. The Malin 500 kV shunt capacitor Group 3 was automatically switched in 45 seconds after the Ross – Lexington line opened. This operation raised the voltage, but the 0.224 Hz system oscillations continued to increase. Five seconds later BPA switched in a 115 kV shunt capacitor group at Walla Walla.

The PDCI also began to fluctuate in response to the ac voltage. The PDCI response during the oscillation indicated that system inertia synchronizing power was decreasing (decreasing dc power while ac power was increasing). At 1548:51, when the ac system oscillations had increased to about 1,000 MW and 60 kV peak-to-peak at Malin, the voltage collapsed. At that time, the 500 kV Buckley – Grizzly line opened via a zone one relay. 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.

The opening of the 500 kV Keeler – Allston line at 1542:37 overloaded the 230 kV lines into the Portland, Oregon area and led to the opening of the 230 kV Ross – Lexington line at 1548:36. Electricity flows shifting east of the Cascades led to additional reactive demands in the McNary area and consequent removal from service of all 13 units at McNary. Finally, growing oscillations reached a level that opened all three lines of the COI in just over one minute.

**California-Oregon Intertie Separation**

One-and-a-half cycles after the Buckley – Grizzly line opened, the Malin 500 kV voltage dropped to 315 kV, and the 500 kV Malin – Round Mountain No.1 and No.2 lines opened by the traveling wave relay switch-into-fault logic at 1548:52:632. These operations were followed shortly by the opening of the 500 kV Captain Jack – Olinda line, which completed separation of the California–Oregon Intertie. The North island frequency rose to 60.9 Hz dropping to 60.4 Hz within two seconds where it remained for about 14 minutes. The frequency crossed 60 Hz three minutes later. During the disturbance, the PDCI experienced several power reductions, and at 1605:12.4, the Sylmar AC Filter Bank 4 opened due to blown fuses, which was probably caused by high harmonic current resulting from reduced voltage operation after the loss of the other valve groups. The PDCI ramp began at 1606:19 and was blocked at 1612.

**Island Details**

**North Island**

This island (Figure 1) 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 line openings on the Northeast/Southeast boundary. Shortly after the Captain Jack – Olinda line opened, the Malin south bus differential relays operated to deenergize the 500/230 kV PacifiCorp transformer, and the 500 kV Grizzly – Summer Lake line opened. All remaining lines on the Oregon section of the COI were opened between John Day and Malin. PacifiCorp lost about 450 MW of customer demand, interrupting service to 154,000 customers in portions of southern and central Oregon, and northern California. Electricity was restored to these customers between 1620 and 1701.
Northern California Island

This island was formed following out-of-step conditions and low voltages between Midway and Vincent substations two seconds after the COI separation and following separation from Sierra Pacific Power Company. At 1548:54.7, the 500 kV Midway – Vincent No.1 and No.2 lines opened when the 500 kV bus voltage at Vincent dropped to 40% of normal. The Midway – Vincent No.3 line opened 65 milliseconds later separating northern and southern California. Frequency within the Northern California Island dropped to 58.3 Hz eight minutes into the disturbance. The under frequency load shedding program within this island removed all ten blocks of customer demand, representing about 50% of the Northern California demand. The Northern California Island lost 7,937 MW of generation and 11,602 MW of demand (about 2.9 million customers).

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 more than three minutes (Figure 3). Some of Pacific Gas & Electric’s (PG&E) demand that was automatically shed was automatically restored after three minutes. (The PG&E load shedding program is designed to restore customer demand in three to six minutes after frequency returns to near 60 Hz.) Over the next five minutes, as demand was automatically restored and additional generation was removed from service, frequency further declined to 58.3 Hz so that the demand that had been automatically restored was removed from service again. Frequency then returned to slightly above 59.0 Hz where it began to stabilize. At 1607, frequency returned to 59.5 Hz where it stayed for about 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 its reconnection with the Northern Island. From 1722 to 1732, PG&E manually shed 2,524 MW of additional customer demand. This demand was restored by 2037.

Connections to southern California were restored at 1847 when the Midway – Vincent No.1 and No.3 lines were returned to service. The Midway – Vincent No.2 line was returned to service at 1848. By 2154, 91% of the PG&E customers had electric service restored; all customers had electric service restored by 0100 on August 11.

Southern Island

This island consisted of Southern California, Arizona, New Mexico, Southern Nevada, Northern Baja, California Mexico, 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 removed from service, along with 15,820 MW of customer demand (about 4.2 million customers).

The frequency in the Southern Island remained below 60 Hz for over an hour (Figure 4). Salt River Project (SRP) manually shed 216 MW of demand (after removing from service 1,444 MW by under frequency relays). As the frequency in the island began to recover and several key units in the island returned to service, system demand restoration began at 1657. The frequency returned to normal at 1655. By 2142, all the demand shed in the Southern Island was restored.
Figure 1
<table>
<thead>
<tr>
<th>EVENT NUMBER</th>
<th>TIME</th>
<th>EVENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>14:06:59:769</td>
<td>500 kV Big Eddy-Dinwiddie single phase-to-ground fault, relay tripped three phases. Flashed to tree.</td>
</tr>
<tr>
<td>1</td>
<td>14:52:37:156</td>
<td>500 kV John Day-Marion single phase-to-ground fault, flashed to tree.</td>
</tr>
<tr>
<td>2</td>
<td>15:42:03:139</td>
<td>500 kV Keesler-Allentown single phase-to-ground fault; opened single pole with unsuccessful reclose. Flashed to tree.</td>
</tr>
<tr>
<td>3</td>
<td>15:47:29</td>
<td>115 kV Merwin-St. Johns line opened due to relay misoperation. (Note: time is approximate)</td>
</tr>
<tr>
<td>4</td>
<td>15:47:36</td>
<td>230 kV Fault on Ross-Leominster line, Flashed to tree. Fault started small fire. (BEGINNING OF DISTURBANCE)</td>
</tr>
<tr>
<td>5</td>
<td>15:47:36</td>
<td>McNary trips 317 MW (2 units) (Time is from Event 4 for rest of table)</td>
</tr>
<tr>
<td>7</td>
<td>15:47:40</td>
<td>McNary trips 215 MW (3 units)</td>
</tr>
<tr>
<td>7</td>
<td>15:47:44</td>
<td>McNary trips 75 MW (1 unit)</td>
</tr>
<tr>
<td>7</td>
<td>15:48:09</td>
<td>McNary trip (1 unit)</td>
</tr>
<tr>
<td>7</td>
<td>15:48:52:613</td>
<td>500 kV Malin-Round Mountain No. 2 line open at Malin.</td>
</tr>
<tr>
<td>8</td>
<td>15:48:52:618</td>
<td>500 kV John Day-Grizzly No. 1 line open at John Day; open at Grizzly at 52.633.</td>
</tr>
<tr>
<td>9</td>
<td>15:48:52:632</td>
<td>500 kV Malin-Round Mountain No. 1 line open at Malin.</td>
</tr>
<tr>
<td>10</td>
<td>15:48:52:641</td>
<td>500 kV John Day-Grizzly No. 2 line open at Grizzly; open at John Day at 52.654.</td>
</tr>
<tr>
<td>11</td>
<td>15:48:52:662</td>
<td>500 kV Captain Jack-Meridian line open at Captain Jack power circuit breaker (PCB Nos. 4983, 4990); reclose blocked.</td>
</tr>
<tr>
<td>12</td>
<td>15:48:52:740</td>
<td>500 kV Grizzly Malin No. 2 line open at Grizzly (PCB No. 6083); open at Malin at 52.760.</td>
</tr>
<tr>
<td>13</td>
<td>15:48:52:778</td>
<td>500 kV Captain Jack-Grizzly line open at Captain Jack (PCB Nos. 4993, 4990); Grizzly open at 52.794.</td>
</tr>
<tr>
<td>14</td>
<td>15:48:52:782</td>
<td>500 kV Grizzly-Maline line open at Maline (PCB Nos. 4977, 4980); (CROSS OPEN BETWEEN OREGON AND CALIFORNIA)</td>
</tr>
<tr>
<td>15</td>
<td>15:48:52:878</td>
<td>500 kV Grizzly-Summer Lake line open at Grizzly; open at Summer Lake at 52.907.</td>
</tr>
<tr>
<td>16</td>
<td>15:48:53:000</td>
<td>500 kV Round Mountain-Mountain No. 3 line open ended at Round Mountain.</td>
</tr>
<tr>
<td>17</td>
<td>15:48:53:255</td>
<td>500 kV Malin-Summer Lake line open at Summer Lake; Malin terminal opens at Summer Lake; Malin terminal opens at 52.358.</td>
</tr>
<tr>
<td>18</td>
<td>15:48:53:622</td>
<td>Colstrip Unit No. 3 and 4 trip off line.</td>
</tr>
<tr>
<td>18</td>
<td>15:48:53:649</td>
<td>Colstrip Unit No. 1 trips off line.</td>
</tr>
<tr>
<td>21</td>
<td>15:48:54:415</td>
<td>345 kV Four Corners-Pino line opens at Four Corners.</td>
</tr>
<tr>
<td>22</td>
<td>15:48:54:576</td>
<td>500 kV North Gila-Imperial Valley line open.</td>
</tr>
<tr>
<td>23</td>
<td>15:48:54:672</td>
<td>500 kV Palo Verde-Devore opens at Palo Verde; at Devore it opens at 54.672.</td>
</tr>
<tr>
<td>24</td>
<td>15:48:54:700</td>
<td>500 kV Midway-Vincent Nos. 1 and 2 lines opened by outage relay.</td>
</tr>
<tr>
<td>26</td>
<td>15:48:54:765</td>
<td>500 kV Midway-Vincent No. 3 line opens due to voltage collapse. (IN SOUTHERN CALIFORNIA NOW SEPARATED FROM SOUTHERN CALIFORNIA)</td>
</tr>
<tr>
<td>27</td>
<td>15:48:54:825</td>
<td>500 kV Navajo-Moenkopi line opens at Navajo.</td>
</tr>
<tr>
<td>28</td>
<td>15:48:54:844</td>
<td>Corcoran terminal of the 133 kV Corcoran-Monument line open (Zone 1).</td>
</tr>
<tr>
<td>29</td>
<td>15:48:54:936</td>
<td>Hesperia terminal of the 345 kV Waterflow-Hesperia line and both terminals of 345 kV Barstow-Hesperia line opened by outage relays.</td>
</tr>
<tr>
<td>30</td>
<td>15:48:54:938</td>
<td>City of Farmington, NM; Gladys-Tucumcari 115 kV tie opened at Gladys Tap by outage relay (two paths now open).</td>
</tr>
<tr>
<td>31</td>
<td>15:48:55</td>
<td>129 kV North Truckee-Summit line, 120 kV California-Summit line, and 60 kV Truckee-Tahoe line open.</td>
</tr>
<tr>
<td>32</td>
<td>15:48:55:141</td>
<td>Diablo Canyon Unit No. 7 trips off line.</td>
</tr>
<tr>
<td>33</td>
<td>15:48:55:405</td>
<td>Diablo Canyon Unit No. 5 trips off line.</td>
</tr>
<tr>
<td>34</td>
<td>15:48:58:496</td>
<td>500 kV Navajo-McCullough line opens at Navajo.</td>
</tr>
<tr>
<td>35</td>
<td>15:48:58:803</td>
<td>300 kV Nanajo-Westwater line opens at Navajo.</td>
</tr>
<tr>
<td>36</td>
<td>15:49:00:000</td>
<td>345 kV East line and Blackwater-de Converter trip out of service.</td>
</tr>
<tr>
<td>37</td>
<td>15:49:00:341</td>
<td>Navajo Unit No. 1 trips off line.</td>
</tr>
<tr>
<td>38</td>
<td>15:49:00:349</td>
<td>Navajo Unit No. 2 trips off line.</td>
</tr>
<tr>
<td>39</td>
<td>15:49:00:000</td>
<td>Glen Canyon Unit Nos. 2, 5, 7, and 8 are removed from service by a remedial action scheme while carrying about 430 MW. These trips were caused by loss of both 345 kV Glen Canyon-Flagstaff lines.</td>
</tr>
<tr>
<td>40</td>
<td>15:49:07:140</td>
<td>Navajo Unit No. 3 trips off line.</td>
</tr>
<tr>
<td>41</td>
<td>15:49:13:315</td>
<td>500 kV Panamint Unit No. 1 trips off line.</td>
</tr>
<tr>
<td>42</td>
<td>15:49:13:405</td>
<td>500 kV Panamint Unit No. 3 trips off line.</td>
</tr>
<tr>
<td>43</td>
<td>15:49:14:000</td>
<td>Hoover Dam: Units 2, 3, and 4 trips off line.</td>
</tr>
<tr>
<td>45</td>
<td>15:49:45:271</td>
<td>Glen Canyon terminals of the 345 kV Glen Canyon-Flagstaff Nos. 1 and 2 lines open.</td>
</tr>
<tr>
<td>47</td>
<td>15:49:52:723</td>
<td>Mohave Unit No. 2 trips off line.</td>
</tr>
<tr>
<td>48</td>
<td>15:50:00:000</td>
<td>Hoover Dam Unit No. 2 and Mohave Dam Unit Nos. 1-4 trips off line.</td>
</tr>
<tr>
<td>49</td>
<td>15:54</td>
<td>55 kV Silver Peak line opens at Silver Peak.</td>
</tr>
<tr>
<td>50</td>
<td>15:54</td>
<td>55 kV Craftbrook-Langdon line opens. (FINA, SYSTEM SEPARATION)</td>
</tr>
</tbody>
</table>

**Figure 2**
Figure 3
Figure 4

System Disturbances — 1996
Alberta Island

At 1544, about five minutes after the Northern Island separated from the rest of WSCC, the British Columbia Hydro and Power Authority (BCHA) to Alberta interconnections (138 kV and 500 kV) opened, separating the Alberta system from the North Island. At the time of the separation, the Interconnection was supplying 1,230 MW to Alberta. Frequency in the Alberta Island dipped to 59.0 Hz. In this island, 146 MW of generation was removed from service and 968 MW of demand was shed by under frequency load shedding, affecting 192,000 customers. Alberta resynchronized with British Columbia at 1629. Electric service was restored to all customers by 1739.

Contributing Factors

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

1. High Northwest Transmission Loading
   - The 500 kV and underlying interconnected transmission system from Canada south through Washington and Oregon to California was heavily loaded due to:
     - Relatively high demands, caused by hot weather throughout much of the WSCC Region.
     - Excellent hydroelectric conditions in Canada and the Northwest, leading to high electricity 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 electricity was flowing into the Northwest from Idaho. The excellent hydro conditions allowed exports to California on the COI of up to 4,750 MW, as determined by operating nomogram limits developed by BPA, PG&E, Idaho Power Company, and PacifiCorp following the July 2, 1996 disturbance.

   During these periods of high transmission loading, BPA operators had previously noticed small changes in electricity 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 support for the transmission system. Two of the outages were caused by flashovers (arcs) to trees resulting from inadequate right-of-way maintenance, and one outage resulted from a circuit breaker being out of service.

   - The 115 kV Allston – Rainier line was out of service due to degraded capability of line hardware. The 115 kV Longview – Lexington line was out of service for fiber-optic cable installation. These outages contributed to system stress following the loss of the Keeler – Allston 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). Because Northwest demands are historically lower in the summer than in the winter, BPA performs most system maintenance during the summer.
3. Triggering Events

- The Keeler – Allston line sagged too close to a tree and arced to ground, forcing the 500 kV Pearl – Keeler line out of service. These outages overloaded parallel 230 kV and 115 kV lines in the Portland area, and depressed the 500 kV voltage.

- Five minutes after the above mentioned lines opened, the 115 kV St. Johns – Merwin line opened due to a zone 1 relay malfunction, contributing to the loading of other parallel lines.

- The overloaded 230 kV Ross – Lexington line sagged too close to a tree and arced to ground, resulting in the removal from service of Swift generation, further depressing the system voltage.

- System protection began removing units from service at McNary and increasing power and voltage oscillations began. These oscillations increased until the three 500 kV COI lines opened due to low voltage.

- Some of the electricity that had been flowing on the COI lines surged east and south through other parts of WSCC causing numerous transmission lines to open due to out-of-step conditions and low voltage, creating islands.

4. Key Factors

- BPA’s right-of-way maintenance was inadequate. Consequently, BPA’s failure to trim trees and remove others identified as a danger to the system caused flashovers from and the opening 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 such that a single-contingency outage (the Keeler – Allston line) would overload parallel transmission lines. BPA operators were aware that on July 13, the 500 kV Pearl – Keeler line sagged too close to a tree, flashed to ground and opened. The July 13 line opening forced open the Keeler – Allston line at Keeler due to a breaker outage. The outage loaded the parallel 115 kV Longview – Allston No.4 line to 109% of capacity. Additionally, a jumper burned open within two minutes due to failure of conductor hardware that had degraded. The jumper was not loaded above its thermal rating. The two 230 kV Allston – Trojan lines and the 230 kV Ross – Lexington line were loaded to their thermal limits. Loading on other lines also increased substantially. Although the July 13 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 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 500 kV Big Eddy – Ostrander, John Day – Marion and Marion – Lane lines were forced out of service. Although the opening of none of these lines was individually judged crucial by BPA dispatchers, the cumulative impact resulted in a weaker system. BPA dispatchers 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. Nor did BPA 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 events to be key facility outages for reporting purposes.

- All the units at McNary were removed from service due to exciter protection as units responded to reduced voltage after the Keeler – Allston and subsequent line trips. Even though the loss of McNary units 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 (opening of the 500 kV Keeler – Allston, 230 kV Ross – Lexington, and other lower voltage lines),
  - a shift of generation to Grand Coulee and Chief Joseph following removal from service of the McNary units, and
  - reduced reactive support to the COI resulting from removal from service of the McNary units and nonparticipation of Coyote Springs, and Hermiston, which were operating on constant power factor control rather than voltage control.

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

5. Widespread Loss of Generation and Demand

- The opening of the COI (which also occurred on July 2) resulted in about 28,000 MW of under frequency load shedding and about 20,000 MW of unanticipated generation removed from service 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 500 kV Keeler – Allston line outage. Inadequate tree trimming practices, operating studies, and instructions to dispatchers also played a significant role in the disturbance.

Due to the significant nature of this system-wide disturbance, there were 32 conclusions and 100 recommendations, which are included in the final report. DAWG selected four key conclusions and associated recommendations to give the reader a sample of the problems identified.
Conclusions & Recommendations

Conclusions:

1. System operation was not in compliance with the WSCC Minimum Operating Reliability Criteria (MORC) prior to the outage of the 500 kV Keeler – Allston line. Outage of this line precipitated the overloading and opening of parallel lines, voltage drops, the undesirable removal from service of key hydro units, and subsequent increasing oscillations, all of which led to opening the California–Oregon Intertie (COI) and other major lines, and the formation of four islands, causing the widespread uncontrolled outage of generation and interrupting electric service to about 7.5 million customers.

Recommendation:

BPA shall assess why it failed to identify that a 500 kV Keeler – Allston 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 were or are being taken shall be submitted to WSCC’s Compliance Monitoring and Operating Practices Subcommittee (CMOPS).

Refer to:
- NERC Operating Policy 2 — Transmission, A. Transmission Operations
- NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
- NERC Operating Policy 4 — System Coordination, A. Monitoring System Conditions
- NERC Operating Policy 4 — System Coordination, B. Coordination With Other Systems — Normal Operations
- NERC Operating Policy 4 — System Coordination, D. System Protection Coordination
- NERC Operating Policy 5 — Emergency Operations, D. Separation from the Interconnection
- NERC Operating Policy 8 — Operating Personnel and Training, C. Training
- NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, A. Adequacy
- NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, B. Security
- NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination
- NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, D. Protection Systems

Conclusion:

10. The system oscillations increased until voltage finally collapsed on the COI, leading to the COI opening and the subsequent formation of four islands in 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 was greatly reduced by fish operation constraints, particularly at The Dalles.

Recommendation:

By November 1997, the WSCC Compliance Work Group (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-owing 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.

Refer to: NERC Operating Policy 1 — Generation Control and Performance, A. Operating Reserve
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, A. General

Conclusion:

12. 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 Intertie Studies Group (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 support due to these operations. The WSCC ISG shall report its findings and recommendations to CMOPS.

Refer to: NERC Operating Policy 2 — Transmission, B. Voltage and Reactive Control
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, II. Resources, Guides, A. General

Conclusion:

31. 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, Standards of Conduct, such close coordination may be limited.

Recommendation:

The WSCC Operating Committee shall assess the potential impact of FERC Order 889 on coordination between generation marketers/owners and transmission operators during disturbances and make appropriate recommendations to improve the coordination of system restoration.

Refer to: NERC Operating Policy 2 — Transmission, A. Transmission Operations
NERC Operating Policy 3 — Interchange, A. Interchange
NERC Operating Policy 5 — Emergency Operations, A. Coordination With Other Systems
NERC Operating Policy 6 — Operations Planning, A. Normal Operations
NERC Planning Principles & Guides, Policies, Procedures, and Principles and Guides, for Planning Reliable Bulk Electric Systems, III. Transmission, Guides, C. Coordination

Anyone interested in obtaining a hard copy of this disturbance report is asked to submit in writing a request to the WECC Technical Staff at the Western Electricity Coordinating Council (formerly the Western Systems Coordinating Council) office.