The Worst That Can Happen

EVEN in the middle of an emergency, there is a prevailing sense of calm and quiet on the control-room floor at the California Independent System Operator's headquarters. Operators silently and continually shift their focus between the ever-fluctuating load curves shown on their computer screens and the giant graphical representation of California's electrical transmission system that extends some 160 feet across an entire wall of the room.

Envision a map of the state turned on its side, with all natural boundaries or political jurisdictions erased and all topographic features stripped away. The Pacific Ocean might as well be the sea of carpet on the floor of the 15,000-square-foot Control Center as your eyes flow from Crescent City to San Diego, left to right along the imaginary coastline.

Instead of cities and rivers, or even the great bowl of the Central Valley or the extended spine of the Sierra Nevada mountain range, what you see are hundreds of lights and lines connecting them: a huge and dynamic electrical diagram at work 24 hours per day, every day.

The small dots of red or green represent the operational status of every major power-generation facility and transmission hub located in the state. Bright LED digits reveal the amount of power flowing from the plants or across tie lines at that exact moment in time. Points of interconnection, characterized by heavy black lines and identifying codes, indicate the routes and voltage levels for the 25,526 circuit-miles of power lines under California ISO's constant watch.

Some lines extend beyond the imaginary perimeter, the high-voltage interties that connect California with the rest of the Western transmission grid. Bold lines represent 500,000-volt (500 KV) power lines that pull electricity from the expansive Columbia River hydroelectric system in the Pacific Northwest, or draw excess power from coal plants and nuclear facilities in the desert Southwest.

The abstract island of California depicted by this map belies the physical reality of integrated operations among dozens of control areas in 11 states that make up the Western grid, as well as the cross-border ties to Mexico and Canada.

At any time of the day or season, power will be flowing in any and all directions, both into and out of the state. But on average, California is a sink where electric energy drains no matter where it might have been created.

On one particular day, June 14, 2000, the room was especially quiet as operators' concentration focused on the San Francisco region.

A record-breaking day of high temperatures—well above 100 degrees Fahrenheit in the normally cool Bay Area—threatened the stability of the entire system in a way that most California ISO staff members had never before faced.

Conversations among operators and their managers were almost beside the point, except for those telephone calls necessary to secure last-minute resources.

There are no windows to the outside world in the control room, unless you consider the full-length glass lens to the adjacent conference room that gives the area its nickname, "the fishbowl." No way to visually confirm whether it is day or night, sunny or stormy beyond the walls of the ISO building on Blue Ravine Road in Folsom, except for those computer screens and digital readouts.

Still, everyone in the room could see that trouble lay ahead.

Jim Detmers, the managing director of grid operations, had a growing sense of unease about the situation. Pacific Gas & Electric, the Northern California utility where Jim spent his early career before joining the ISO, was projecting an all-time record for electricity deliveries later that afternoon.

Resources were tight because the heat wave extended through much of the region, and imported energy was less available than anticipated. The unplanned outage that morning of a key generation plant in Pittsburg made the situation even tighter.

From long experience in keeping the lights on for PG&E customers, Detmers knew that a widespread and costly system failure was inevitable if loads kept climbing at this pace. And he knew there was only one way to prevent it.

For the first time in the more than two years since it had assumed control over the transmission grid in April of 1998, the California Independent System Operator was about to require that PG&E cut delivery of power to customers in San Francisco, the East Bay and Silicon Valley.

These were not the rare but sometimes necessary voluntary disruptions of service to industrial energy users who had signed discount-rate, "interruptible contracts" with their utilities. Most of PG&E's largest industrial customers already had agreed to shut down or reduce energy use, but the resulting 500-megawatt reduction—about half the output of a nuclear power plant—did not correct the problem.

What was necessary now was to shut off power to specific and identified blocks of utility customers in units of 100 MW. The outages would rotate by hour and affect as many as 100,000 customers per block. By 2:00 p.m., the decision was unavoidable. PG&E would need to drop as much as 200 MW, and neighboring municipal utility districts, even though they were not technically part of the ISO system, would also need to cut some service.

The operators were not even certain they could limit the outages to such small blocks, even though they had previously run simulations to provide assurance that the blackouts would not spiral out of control.

"You know we had never done this back at the utilities," Detmers explained in a pained voice. "You'd pull every trick out of the hat you could possibly think about pulling, and when it came down to giving the order to drop load, firm load, due to just lack of electricity, it was like we failed. I felt like we had failed."

Despite the passage of time and the perspective of having survived nearly a full year of emergency declarations, blackouts and the many, many last-minute saves that characterized the great California Power Crisis of 2000-01, both Detmers and colleague Tracy Bibb still felt the sting of defeat from needing to cut the flow of electricity on that hot June afternoon.

"We failed," Bibb concurred. "We failed," Detmers repeated softly.

In reality, the problem was much more than "just lack of electricity," as measured in unavailable megawatts. Similarly, the decision to shed firm load was not a failure in and of itself but a way of preventing something far worse—a swift and substantial drop in the frequency of power flows that could trip power plants across the entire system, permanently damaging transformers and other sensitive equipment.

To the general public, the job of an electric utility is to keep the lights on at a somewhat reasonable cost, as usually determined by appointed regulators or a publicly elected board. For a transmission controller, however, the operative phrase is "maintaining 60 cycles"; that is, holding a standard level of frequency for the waves of electrical energy that flow from power plants to transmission lines to customers. The cost is secondary.

Through a century of trial and error, of daily success and occasional failure, the American electric industry has chosen 60 cycles as its standard, regardless of whether the voltage level is 500 KV, as on the big interties, or 120 volts running through the circuits and appliances in your home.

The Daily High-Wire Act

Some fluctuation around the 60-cycles-per-second (also known as 60 hertz) figure is tolerable, noted California ISO chief executive officer Terry Winter, but 60 is the magic number to ensure reliable operations for power flowing throughout North America. Anything significantly above or below that level signals trouble. Utility engineers, under the auspices of the Western Electricity Coordinating Council (WECC) or the North American Electric Reliability Council (NERC)—the industry agencies that set reliability standards—select certain frequencies as benchmarks for remedial action in order to maintain stability.

Too much demand compared to the amount of generation capacity causes frequency levels to fall. An unexpected loss of load, perhaps caused by a lightning strike or a tree falling onto a power line to disconnect customers from the system, will bring a frequency excursion above 60 cycles. Either event can occur, and they do, sometimes daily.

Extreme deviations in either direction cause automatic systems to kick in to try to restore the balance and prevent a cascading outage.

“At 59.56 hertz, the first set of relays drops generation and load,” Winter explained. “At 59.3, it’s all gone.”

Imagine a circus tightrope walker—the utility transmission system operator—hovering without a safety net some hundreds of feet above the ground. The tension of the rope is measured by its frequency response, with power generation acting like a helium balloon to tug the line upward. Electricity consumption, called load, is a weight exerting a downward pull.

As long as the two forces balance each other, and the frequency stays at 60 cycles, the acrobat can successfully cross the chasm that represents each day’s supply/demand curve. This equilibrium is measured not just hourly but essentially every four seconds.

But that’s too simple of a model, Winter cautioned, because of the complexity of a network system in which thousands of generation sources pump power into the system while millions of load pockets—power users—pull electrons out.

“I use the example in a network,” he said. “If you take two chairs and tie a spider-web of rubber bands between the two chairs, and you hang all the generators as helium balloons and you hang all the load as weights on this network, you can see as the balloons rise up, the load comes with it. If the balloons start losing pressure or generation, the weight pulls it down. And it all flows on this grid, moving up and down. What you don’t want to have happen is to suddenly have a balloon break or a load fall off, because then this whole spider web of rubber bands starts popping up and down. If it goes up or down so far that it disconnects balloons or load, then you have what we call the unstable system. It all falls apart.”

If unchecked, the frequency fluctuation and resulting voltage instability could spread in a matter of seconds, triggering a massive and cascading outage that might not be contained within the local region. All those dots of light and LED readouts on the big map would go dark. Tens of millions of people from British Columbia to Baja California would flip their light switches or try to turn on their televisions and radios to find out what was wrong, but there would be no juice in the system, no power, no light, and no way of knowing exactly how long it would take to restore service.

It had happened before.

Before the extended California crisis, the date August 10, 1996, was fixed in the memories of utility personnel and control-room operators as the single worst event in the history of the Western interconnection.

On that date, four million people and hundreds of thousands of businesses in 11 states lost power for much of the day. It was the second system outage of that summer but much more widespread than a prior incident in July.

Perhaps it was not as severe as the New York Blackout of 1965, which plunged much of the Eastern seaboard into darkness, or as influential as that event had been in eliciting national policies for the creation of eight separate “reliability regions” like the WECC across North America. Nonetheless, the August 10 outage became the hobgoblin of reliability in the West.

“This should be put in the same category as a nuclear meltdown,” said California Public Utilities Commission member Jessie Knight, Jr., at the time.[1] It was an episode that no transmission professional would ever want to see repeated—and certainly not on his or her watch.

Anatomy of a Catastrophe

Occurring during an extremely hot Saturday, when PG&E and smaller public power districts in Northern California were on their way to setting new record peak loads, the triggering event of the August 1996 outage was the instantaneous grounding of power. A heavily loaded transmission line in the Pacific Northwest came into contact with a tree.

This was recognized by the system as if it were a huge, instantaneous increase in demand or a sudden loss of generation.

As you might expect, however, there was a full and complicated set of circumstances underlying the incident. Controllers at the Bonneville Power Administration, the federal power-marketing agency that owned and operated the line, later admitted they had missed some of the warning signs of a potential disaster.

Other utilities affected by the outage blamed BPA for a failure to communicate that three high-voltage transmission lines had relayed out of service earlier in the day, weakening the system in advance of the triggering event. With more warning, they complained, they might have been able to shield their systems from the catastrophe.

At about 3:40 p.m., the 500 KV line connecting the Keeler and Alston substations in Oregon was carrying a full load of power for use in the Northwest and for export to California.

The combination of hot temperatures and being fully loaded caused the line to sag so much that it touched the tree line in a heavily wooded area, immediately shorting the line.

The resulting frequency oscillations set up a cascade of outage events, knocking off line 13 hydroelectric units at McNary Dam, tripping the direct-current (DC) intertie that runs between Oregon and Southern California, and causing a breakdown in the connections between utility control areas—not only between the Northwest and California but also in Nevada, New Mexico and Arizona.

That triggered further outages throughout the West.

The reliability criteria for such a system outage call for “islanding,” or separating control areas into autonomous pools so that service can be restored more quickly. The problem was that with so much generation out of service, controllers did not have enough residual voltage support to bring power stations back on line. Huge nuclear power stations at Diablo Canyon and San Onofre in California and at Palo Verde in Arizona fell from full capacity to zero in a matter of minutes. Restoring power after such a “scram” at a nuclear unit can take days. Throughout the system, generation had to be brought back from what operators call a "black start condition."[2]

Ed Riley, now California ISO's director of regional coordination, was an area controller for the Los Angeles Department of Water & Power at the time of the outage. That hot Saturday, he was enjoying an outing with his grandson at Disneyland in nearby Anaheim. "All of a sudden, people start coming out of the rides and there's nothing going on," he recalled. The amusement park was silent and still. "I'm going, 'Hmm, must be a local power outage.' And then my pager went off," signaling that something far more serious had occurred. "So I had to get back to work."

'It's All on the Ground'

To be sure, there had been several other serious system events during the careers of California ISO operators, both before and after the corporation had been created. When Detmers and Bibb reminisced about them, it was like listening to two tall-tale tellers finishing each other's thoughts and trying to top each other's stories.

"The biggest breakup the Western states had ever seen prior to August 10th was December 22, 1982, at 4:29 p.m. I was there. It was burned into my vision. I was there that day," Bibb said. Fierce winds had blown down six 500 KV transmission lines in PG&E's territory east of San Francisco, and the resulting shocks to the grid blacked out up to four million people in three states.[3]

Detmers countered, citing the major windstorm of December 14, 1995. "It blew down lines, and the entire Western United States went unstable," he said.

About 1.75 million PG&E customers lost power for several hours, some for days.[4] "That was the big one you never want to see again, when the wind exceeded 100 miles per hour, exceeded the engineering of the lines and took out the towers. I remember the phone call with the guy in the helicopter. He had just flown from Table to Round Mountain [along the Pacific Intertie in Northern California] and it was still during the storm and they were flying to find out why the lines were out. The towers were gone. They were all laid down for eight miles. Didn't see it when they flew over the first time.

They started coming back, and he called me on his cell phone at the window of the helicopter. He was shook up. He said, 'It's all laying on the ground.'"

The two veterans batted about memories of other big outage events, ranging from the 1989 Loma Prieta earthquake centered near Santa Cruz to the 1992 Northridge temblor that wrecked a wide area of Southern California. There was the accidental grounding of energy by a PG&E substation repair crew in December 1998 that left San Francisco without power for a full day and led to unprecedented sanctions against the utility by the new Independent System Operator.

None of it really compared with the August event, which made them "look like a walk in the park," Bibb concluded. "August 10th was catastrophic, because of the magnitude of how many people were off, how many transmission lines tripped out, how many generators tripped off. And having to rebuild the system in many cases from a black start. Yeah, everything ripped apart. Diablo was off, San Onofre units were off, all the nuclear was off."

And yet, the ISO's June 14, 2000, call for firm-load curtailments over a 90-minute period was something these professionals would take far more personally and emotionally than any of the other incidents they had ever experienced. "That was just dealing with our work," Detmers said of the past reliability episodes. "So we were working, doing what we had to do to operate the system, to engineer it, to put the whole thing back together to get the lights back on. We knew what the problems were; it was a storm, it was a quake and whatever. We knew what the problem was and we were dealing with it."

June 14, 2000, was different because of a sense, still lingering, of personal failure.

"In my mind, I pictured people stranded in elevators. I pictured people stranded in stores and checkout lines. All I could think about was the inconvenience, and sitting here thinking . . . thinking, what rock did we not look under to maybe prevent this," he said.

Detmers, Bibb and nearly everybody else at California ISO knew that June 14th was just the beginning of a long, terrible summer. What they didn't realize was that the situation would turn out to be worse than they feared.

Θ

by Arthur O'Donnell, excerpted from *Soul of the Grid: A Cultural Biography of the California Independent System Operator* publication pending from iUniverse