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Blackout 2011 – Volume I

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Blackout 2011 -Volume I
Events Leading Up to the Outage

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This course is a based on an April 2012 report by the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation titled, Arizona – Southern California Outage on September 8, 2011. The Report has been edited for brevity and clarity for this course.

Preface

On the afternoon of September 8, 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving approximately 2.7 million customers without power. The outages affected parts of Arizona, Southern California, and Baja California, Mexico. All of the San Diego area lost power, with nearly one-and-a-half million customers losing power, some for up to 12 hours. The disturbance occurred near rush hour, on a business day, snarling traffic for hours. Schools and businesses closed, some flights and public transportation were disrupted, water and sewage pumping stations lost power, and beaches were closed due to sewage spills. Millions went without air conditioning on a hot day.

Immediately following the blackout, FERC and NERC assembled a team of technical experts to investigate exactly what happened, why it happened, and what could be done to minimize the chance of future outages. The scope of NERC's investigation was to determine the causes of the blackout, how to reduce the likelihood of future cascading blackouts, and how to minimize the impacts of any that do occur. NERC focused its analysis on factual and technical issues including power system operations, planning, design, protection and control, and maintenance.

This is Volume I of a two part series about the September 8th outage. This course looks at the conditions on the bulk electric system that existed prior to and during the blackout, and explains how the blackout occurred. It covers the events leading up to the blackout and gives an overview of the conditions prior to the start of the system failure. Volume II reviews the causes, findings of the investigating committee, and gives recommendations to minimize a future event of this type.

Introduction

The loss of a single 500 kilovolt (kV) transmission line initiated the September 8, 2011 event, but was not the sole cause of the widespread outages. The system is designed, and should be operated, to withstand the loss of a single line, even one as large as 500 kV. The affected line—Arizona Public Service's (APS) Hassayampa-N. Gila 500 kV line (H-NG)—is a segment of the Southwest Power Link (SWPL), a major transmission corridor that transports power in an east-west direction, from generators in Arizona, through the service territory of Imperial Irrigation District (IID), into the San Diego area. It had tripped on multiple occasions, as recently as July 7, 2011, without causing cascading outages.

With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the system, increasing flows through lower voltage systems to the north of the SWPL, as power continued to flow into San Diego on a hot day during hours of peak demand. Combined with lower than peak generation levels in San Diego and Mexico, this instantaneous redistribution of power flows created sizeable voltage deviations and equipment overloads to the north of the SWPL. Significant overloading occurred on three of IID's 230/92 kV transformers located at the Coachella Valley (CV) and Ramon substations, as well as on Western Electricity Coordinating Council (WECC) Path 44, located south of the San Onofre Nuclear Generating Station (SONGS) in Southern California.

Path 44, also referred to as "South of SONGS," is an aggregation of five 230 kV lines that delivers power in a north-south direction from the Southern California Edison (SCE) footprint in the Los Angeles area into the SDG&E footprint.

The flow redistributions, voltage deviations, and resulting overloads had a ripple effect, as transformers, transmission lines, and generating units tripped offline, initiating automatic load shedding throughout the region in a relatively short time span. Just seconds before the blackout, Path 44 carried all flows into the San Diego area as well as parts of Arizona and Mexico. Eventually, the excessive loading on Path 44 initiated an intertie separation scheme at SONGS, designed to separate SDG&E from Southern California Edison (SCE). The SONGS separation scheme separated SDG&E from Path 44, led to the loss of the SONGS nuclear units, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's (CFE) Baja California Control Area. During the 11 minutes of the event, the WECC Reliability Coordinator (WECC RC) issued no directives and only limited mitigating actions were taken by the Transmission Operators of the affected areas.

CFE is Mexico's state-owned utility. Only its Baja California Control Area was affected on September 8, 2011.

As a result of the cascading outages stemming from this event, customers in the SDG&E, IID, Arizona Public Service (APS), Western Area Power Administration-Lower Colorado (WALC), and CFE territories lost power, some for multiple hours extending into the next day. Specifically,

- SDG&E lost 4,293 Megawatts (MW) of firm load, affecting approximately 1.4 million customers.
- CFE lost 2,150 MW of net firm load, affecting approximately 1.1 million customers.
- IID lost 929 MW of firm load, affecting approximately 146,000 customers.
- APS lost 389 MW of firm load, affecting approximately 70,000 customers.
- WALC lost 74 MW of firm load, 64 MW of which affected APS's customers. The remaining 10 MW affected 5 WALC customers.

After the blackout, the affected entities promptly instituted their respective restoration processes. All of the affected entities had access to power from their own or neighboring systems and, therefore, did not need to use "black start" plans. Although there were some delays in the restoration process due to communication and coordination issues between entities, the process was generally effective. SDG&E took 12 hours to restore 100% of its load, and CFE took 10 hours to restore 100% of its load. IID, APS, and WALC restored power to 100% of their customers in approximately 6 hours. The affected entities also worked to restore generators and transmission lines that tripped during the event. IID and APS restored generation—333 MW for IID and 76 MW for APS—in 5 hours.

Black start plans work to energize systems using internal generation to get from shutdown to operating condition without assistance from the Bulk Electric System (BES).

Meanwhile, CFE restored 1,915 MW of tripped generation in 56 hours; SDG&E restored 2,229 MW of tripped generation in 39 hours; and SCE restored 2,428 MW of tripped generation in 87 hours. IID restored its 230 kV transmission system in 12 hours and its 161 kV system in 9 hours; APS restored H-NG in 2 hours; SDG&E restored its 230 kV system in 12 hours; WALC restored its 161 kV system in 1.5 hours; and CFE restored its 230 kV system in 13 hours and its 115 kV system in 10 hours.

The following map (see Figure 1), showing the areas affected by the September 8th event and the key facilities involved during the event, can be used as a reference throughout the report:

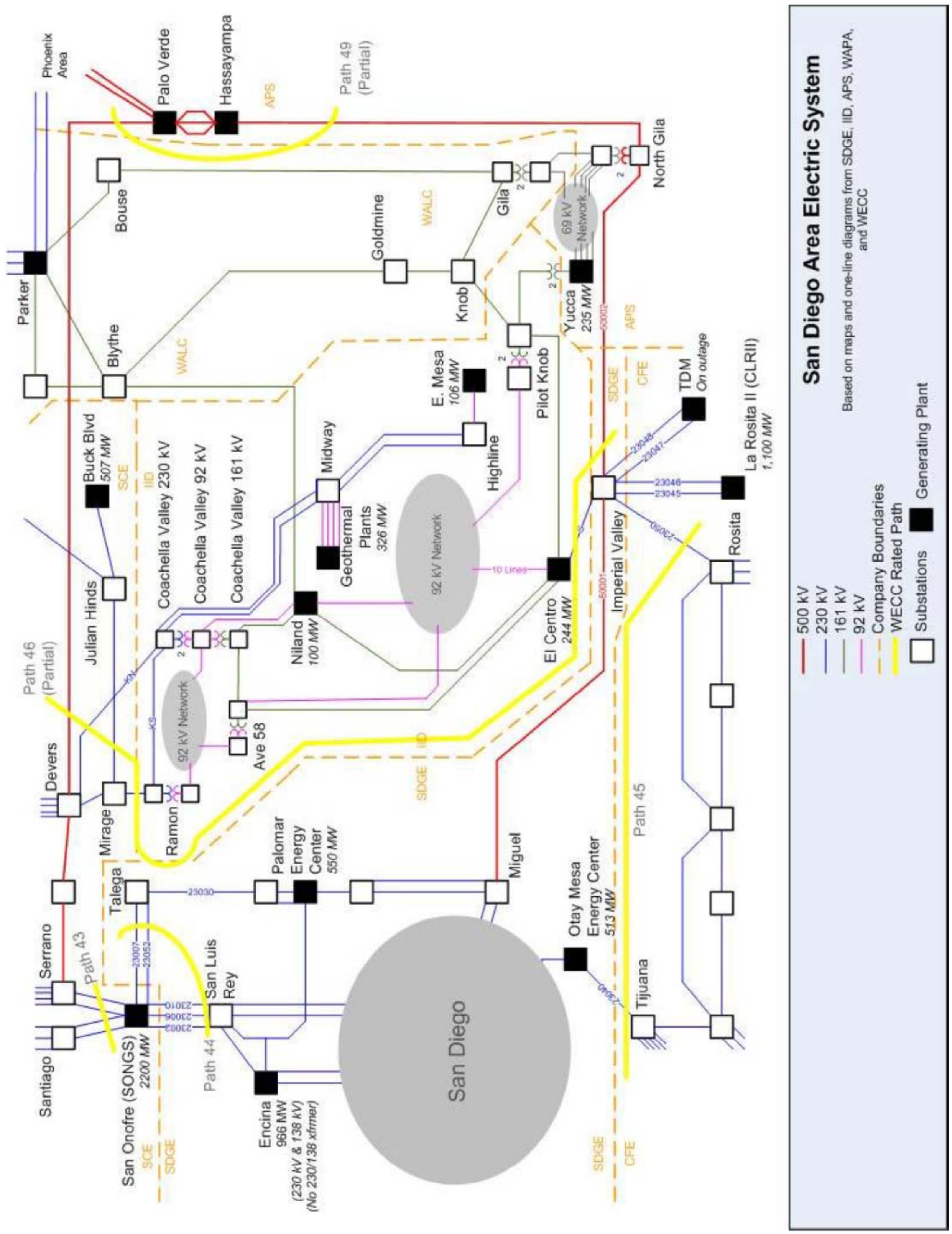
San Diego Area Electric System
Based on maps and one-line diagrams from SDGE, IID, APS, WAPA, and WECC
500 kV
230 kV
161 kV
92 kV
Company Boundaries
WECC Rated Path
Substations
Generating Plant
Phoenix Area
Palo Verde
Hassayampa
APS
Path 49 (Partial)
Parker
Bouse
Blythe
WALC
Goldmine
Knob
Gila
North Gila
69 kV Network
Yucca
235 MW
Pilot Knob
E. Mesa
106 MW
Highline
Buck Blvd
507 MW
SCE
IID
Coachella Valley 230 kV
Coachella Valley 92 kV
Coachella Valley 161 kV
Midway
Geothermal Plants
326 MW
92 kV Network
10 Lines
Julian Hinds
Niland
100 MW
El Centro
244 MW
Imperial Valley
SDGE
CFE
TDM
On outage
La Rosita II (CLRII)
1,100 MW
Rosita
Path 46 (Partial)
Devers
Mirage
Ramon
Ave 58
Path 45
Serrano
Path 43
Talega
Palomar Energy Center
550 MW
Miguel
Otay Mesa Energy Center
513 MW
Santiago
San Onofre (SONGS)
2200 MW
San Luis Rey
Path 44
Encina
966 MW
(230 kV & 138 kV)
(No 230/138 xfrmer)
San Diego
Tijuana

Figure 1

The September 8, 2011, event showed that the system was not being operated in a secure N-1 state. This failure stemmed primarily from weaknesses in two broad areas—operations planning and real-time situational awareness—which, if done properly, would have allowed system operators to proactively operate the system in a secure N-1 state during normal system conditions and to restore the system to a secure N-1 state as soon as possible, but no longer than 30 minutes.

> Reliability Standards require that the BES be operated so that it generally remains in a reliable condition, without instability, uncontrolled separation or cascading, even with the occurrence of any single contingency, such as the loss of a generator, transformer, or transmission line. This is commonly known as the "**N-1 criterion**."

Without adequate planning and situational awareness, entities responsible for operating and overseeing the transmission system could not ensure reliable operations within System Operating Limits (SOLs) or prevent cascading outages in the event of a single contingency. Inadequate situational awareness and planning were also identified as causes of the 2003 blackout that affected an estimated 50 million people in the United States and Canada.

The inquiry also identified other underlying factors that contributed to the event, including: Not identifying and studying the impact on Bulk-Power System (BPS) reliability of sub-100 kV facilities in planning and operations; the failure to recognize Interconnection Reliability Operating Limits (IROLs) in the Western Interconnection; not studying and coordinating the effect of protection systems, including Remedial Action Schemes (RASs), during plausible contingency scenarios; and not providing effective tools and operating instructions for use when reclosing lines with large phase angle differences across the reclosing breakers.

With regard to operations planning, some of the affected entities' seasonal, next-day, and real-time studies do not adequately consider: Operations of facilities in external networks, including the status of transmission facilities, expected generation output, and load forecasts; external contingencies that could impact their systems or internal contingencies that could impact their neighbors' systems; and the impact on BPS reliability of internal and external sub-100 kV facilities. As a result, these entities' operations studies did not accurately predict the impact of the loss of APS's H-NG or the loss of IID's three 230/92 kV transformers. If the affected entities had more accurately predicted the impact of these losses prior to the event, these entities could have taken appropriate pre-contingency measures, such as dispatching additional generation to mitigate overloads and prevent cascading outages.

To improve operations planning in the WECC region, this report makes several recommendations designed to ensure that TOPs and BAs, as appropriate: Obtain information on the operations of neighboring BAs and TOPs, including transmission outages, generation outages and schedules, load forecasts, and scheduled interchanges; identify and plan for external contingencies that could impact their systems and internal contingencies that could impact their neighbors' systems; and consider facilities operated at less than 100 kV that could impact BPS reliability. This effort should include a coordinated review of planning studies to ensure that operation of the affected Rated Paths will not result in the loss of non-consequential load, system instability, or cascading outages, with voltage and thermal limits within applicable ratings for N-1 contingencies originating from within or outside an entity's footprint.

The September 8^{th} event also exposed entities' lack of adequate real-time situational awareness of conditions and contingencies throughout the Western Interconnection. For example, many entities' real-time tools, such as State Estimator and Real-Time Contingency Analysis (RTCA), are restricted by models that do not accurately or fully reflect facilities and operations of external systems to ensure operation of the BPS in a secure N-1 state. Also, some entities' real-time tools are not adequate or operational to alert operators to significant conditions or potential contingencies on their systems or neighboring systems. The lack of adequate situational awareness limits entities' ability to identify and plan for the next most critical contingency to prevent instability, uncontrolled separation, or cascading outages. If some of the affected entities had been aware of real-time external conditions and run (or reviewed) studies on the conditions prior to the onset of the event, they would have been better prepared for the impacts when the event started and may have avoided the cascading that occurred.

To improve situational awareness in the WECC region, this report makes several recommendations: Expand entities' external visibility in their models through, for example, more complete data sharing; improve the use of real-time tools to ensure the constant monitoring of potential internal or external contingencies that could affect reliable operations; and improve communications among entities to help maintain situational awareness. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS. These improvements will enable system operators to utilize real-time operating tools to proactively operate the system in a secure N-1 state.

In addition to the planning and situational awareness issues, several other factors contributed to the September 8^{th} event. For example, WECC RC and affected entities do not consistently recognize the adverse impact that sub-100 kV facilities can have on BPS reliability. The prevailing SOLs should have included the effects of facilities that had not been identified and classified as part of the BES, as well as the effects of critical facilities such as Special Protection Systems (SPSs) and the SONGS separation scheme. Relevant to the event, these entities did not consider IID's 92 kV network and facilities, including the CV and Ramon 230/92 kV transformers, as part of the BES, despite some previous studies indicating their impact on the BPS due to the fact they were electrically in parallel with higher-voltage facilities. If these facilities had been designated as part of the BES, or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems, the cascading outages may have been avoided. Accordingly, the inquiry makes a recommendation to ensure that facilities that can impact BPS reliability, regardless of voltage level, are considered for classification as part of the BES and/or studied as part of entities' planning in various time horizons.

The inquiry also found some significant issues with protection system settings and coordination. For example, IID used conservative overload relay trip settings on its CV transformers. The relays were set to trip at 127% of the transformers' normal rating, which is just above the transformers' emergency rating (110% of normal rating). Such a narrow margin between the emergency rating and overload trip setting resulted in the facilities being automatically removed from service without providing operators enough time to mitigate the overloads. As a result of these settings, both CV transformers tripped within 40 seconds of H-NG tripping, initiating cascading outages. To avoid a similar problem in the future, the inquiry recommends that IID and other Transmission Owners (TOs) review their transformers' overload protection relay settings. A good guideline for protective relay settings is Reliability Standard PRC-023-1 R1.11, which states that relays be "set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater." TOPs should also plan to take proper pre-contingency mitigation measures with due consideration for the applicable emergency ratings and overload protection settings (MW and time delay) before a facility loads to its relay trip point and is automatically removed from service.

The SONGS separation scheme's operation provides another example of the lack of studies on, and coordination of, protection systems. This scheme, classified by SCE as a "Safety Net," had a significant impact on BPS reliability, separating SDG&E from

SCE, resulting in the loss of both SONGS nuclear generators, and blacking out SDG&E and CFE. Nevertheless, none of the affected entities, including SCE, as the owner and operator of the scheme, studied its impact on BPS reliability. The September 8th event shows that all protection systems and separation schemes, including Safety Nets, RASs, and SPSs, should be studied and coordinated periodically to understand their impact on BPS reliability to ensure their operation, inadvertent operation, or misoperation does not have unintended or undesirable effects.

I. System Overview

This section provides an overview of: The Western Interconnection and its position in the North American electric grid; the reliability entities responsible for operating the grid; a description of the affected entities; and a discussion of the interconnected nature of these entities.

The Western Interconnection

NERC shares its mission of ensuring the reliability of the BPS in North America with eight Reliability Entities (Res) through a series of delegation of authority agreements. WECC is the designated RE responsible for coordinating and promoting BPS reliability in the Western Interconnection. In its capacity as the RE, WECC monitors and enforces compliance with Reliability Standards by the users, owners, and operators of the BPS. WECC also functions as an Interconnection-wide planning facilitator, aiding in transmission and resource integration planning at the request of its members, as well as a provider of data, analysis, and studies related to transmission planning and reliability issues.

The WECC region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, the states of Washington, Oregon, California, Idaho, Nevada, Utah, Arizona, Colorado, Wyoming, and portions of Montana, South Dakota, New Mexico, and Texas. See Figure 2, on the next page. The WECC region is nearly 1.8 million square miles in size, has over 126,000 miles of transmission, and serves a population of 78 million. WECC contains 37 BAs and 53 TOPs. Due to the diverse characteristics of this extensive region, WECC encounters unique challenges in day-to-day coordination of its interconnected system. WECC is tied to the Eastern Interconnection through a number of high-voltage direct current transmission ties.

WECC also operates two RC offices that provide situational awareness and real-time monitoring of the entire Western Interconnection. WECC RC was an affected entity, and will be discussed with other affected entities below.

Reliability Responsibilities

NERC categorizes the entities responsible for planning and operating the BPS in a reliable manner into multiple functional entity types. The NERC functional entity types most relevant to this event are BAs, TOs, TOPs, Generator Operators (GOPs), Planning Coordinators (PCs), Transmission Planners (TPs), and RCs. These functions are described in more detail in NERC's Reliability Functional Model. Some of the affected entities conduct multiple reliability functions.

Balancing Authority
The BA integrates resource plans ahead of time, maintains in real time the balance of electricity resources (generation and interchange) and electricity demand or load within its footprint, and supports the Interconnection frequency in real time. There are 37 BAs in the WECC footprint. The following five BAs were affected by the event: APS, IID, WALC, CAISO, and CFE.

Figure 2

Transmission Owner, Transmission Operator and Generator Operator

The TO owns and maintains transmission facilities. The TOP is responsible for the real-time operation of the transmission assets under its purview. The TOP has the authority to take corrective actions to ensure that its area operates reliably. The TOP performs reliability analyses, including seasonal and next-day planning and RTCA, and coordinates its analyses and operations with neighboring BAs and TOPs to achieve reliable operations. It also develops contingency plans, operates within established SOLs, and monitors operations of the transmission facilities within its area. There are 53 TOPs in the WECC region. The following seven TOPs were affected by the event: APS, IID, WALC, CAISO, CFE, SDG&E, and SCE. The GOP operates generating unit(s) and performs the functions of supplying energy and other services required to support reliable system operations, such as providing regulation and reserve capacity.

Planning Coordinator

The PC is responsible for coordinating and integrating transmission facility and service plans, resource plans, and protection systems.

Transmission Planner

The TP is responsible for developing a long-term (generally one year and beyond) plan for the reliability of the interconnected bulk transmission systems within its portion of the Planning Coordinator Area.

Reliability Coordinator

The RC and TOP have similar roles, but different scopes. The TOP directly maintains reliability for its own defined area. The RC is the "highest level of authority" according to NERC, and maintains reliability for the Interconnection as a whole. Thus, the RC is expected to have a "wide-area" view of the entire Interconnection, beyond what any single TOP could observe, to ensure operation within IROLs.

The RC oversees both transmission and balancing operations, and it has the authority to direct other functional entities to take certain actions to ensure reliable operation. The RC, for example, may direct a TOP to take whatever action is necessary to ensure that IROLs are not exceeded. The RC performs reliability analyses including next-day planning and RTCA for the Interconnection, but these studies are not intended to substitute for TOPs' studies of their own areas. Other responsibilities of the RC include responding to requests from TOPs to assist in mitigating equipment overloads. The RC also coordinates with TOPs on system restoration plans, contingency plans, and reliability-related services.

Descriptions of Affected Entities

The following entities were affected by the September 8th event:

WECC RC

In its capacity as the RC, WECC is the highest level of authority responsible for the reliable operation of the BPS in the Western Interconnection. WECC RC oversees the operation of the Western Interconnection in real time, receiving data from entities throughout the entire Interconnection, and providing high-level situational awareness for the entire system. WECC RC can direct the entities it oversees to take certain actions in order to preserve system reliability. Although WECC is both an RE and an RC, these two functions are organizationally separated.

Imperial Irrigation District (IID)

IID, which encompasses the Imperial Valley, the eastern part of Coachella Valley in Riverside County, and a small portion of San Diego County, in California, owns and operates generation, transmission, and distribution facilities in its service area to provide comprehensive electric service to its customers. Thus, IID is a vertically integrated utility. IID's generation consists of hydroelectric units on the All-American Canal as well as oil-, nuclear-, coal-, and gas-fired generation facilities, with a total net capability of 514 MW. IID purchases power from other electric utilities to meet its peak demands in summer, which can exceed 990 MW. IID's transmission system consists of approximately 1,400 miles of 500, 230, 161, and 92 kV lines, as well as 26 transmission substations. Among other NERC registrations, IID is a TOP, BA, and TP responsible for resource and transmission planning, load balancing, and frequency support for its footprint.

Arizona Public Service (APS)

APS is a vertically integrated utility that serves a 50,000 square mile territory spanning 11 of Arizona's 15 counties. Among other NERC registrations, APS is the TOP and BA for its territory. APS engages in both marketing and grid operation functions, which are separated. APS owns and operates transmission facilities at the 500 (including H-NG), 345, 230, 115, and 69 kV levels, and owns approximately 6,300 MW of installed generation capacity. APS's 2011 peak load was 7,087 MW.

Western Area Power Administration – Lower Colorado (WALC)

WALC is one of the four entities constituting the Western Area Power Administration, a federal power marketer within the United States Department of Energy. WALC operates in Arizona, Southern California, Colorado, Utah, New Mexico, and Nevada, and is registered with NERC as a BA, TOP, and PC for its footprint. As a net exporter of energy, WALC's territory has over 6,200 MW of generation, serving at most 2,100 MW of peak load. A majority of WALC's generation is federal hydroelectric facilities, with the balance consisting of thermal generation owned and operated by independent power producers. WALC also operates an extensive transmission network within its footprint, and is interconnected with APS, SCE, and nine other balancing areas.

San Onofre Nuclear Generating Station (SONGS)

SONGS is a two-unit nuclear generation facility capable of producing approximately 2,200 MW of power, and is located north of San Diego. SONGS produces approximately 19% of the power used by SCE customers and 25% of the power used by SDG&E customers. SONGS is jointly owned by SCE (78.21%), SDG&E (20%), and the City of Riverside (1.79%). SCE, as TO and GO, is responsible for ensuring the safe and reliable operation of SONGS within the grid.

California Independent System Operator (CAISO)

CAISO runs the primary market for wholesale electric power and open-access transmission in California, and manages the high-voltage transmission lines that make up approximately 80% of California's power grid. CAISO operates its market through day-ahead and hour-ahead markets, as well as scheduling power in real time as necessary. Among other registrations, CAISO is PC and BA for most of California, including the city of San Diego. It also acts as TOP for several entities within its footprint, including SDG&E and SCE. CAISO likewise engages in modeling and planning functions in order to ensure long-term grid reliability, as well as identifying infrastructure upgrades necessary for grid function.

San Diego Gas and Electric (SDG&E)

SDG&E is a utility that serves both electricity and natural gas to its customers in San Diego County and a portion of southern Orange County, and is the primary utility for the city of San Diego. SDG&E owns relatively little generation—approximately 600 MW—although generation owned by others in its footprint brings the total generation capacity of the area above 3,350 MW. Peak load for the area can exceed 4,500 MW in the summer. SDG&E also operates an extensive high-voltage transmission network at the 500, 230, and 138 kV levels. SDG&E, operating as a TOP within CAISO's BA footprint, has delegated part of its responsibilities as a TOP to CAISO.

Comisión Federal de Electricidad – Baja California Control Area (CFE)

CFE is the only electric utility in Mexico, servicing up to 98% of the total population. CFE's Baja California Control Area is not connected to the rest of Mexico's electric grid but is connected to the Western Interconnection. CFE's Baja California Control Area covers the northwest corner of Mexico, including the cities of Tijuana, Rosarito, Tecate, Ensenada, Mexicali, and San Luis Rio Colorado. CFE's Baja California Control Area operates transmission systems at the 230, 161, 115, and 69 kV levels, and owns 2,039 MW of gross generating capacity and the rights to a 489 MW independent power producer within the Baja California Control Area. CFE's Baja California Control Area had a net peak load of 2,184 MW for summer 2010. CFE's Baja California Control Area is connected at the 230 kV level with SDG&E through two transmission lines on WECC Path 45. CFE functions as the TO, TOP, and BA for its Baja California Control Area under the oversight of WECC RC. For the remainder of this report, "CFE" refers only to its Baja California Control Area.

Southern California Edison (SCE)
SCE is a large investor-owned utility which provides electricity in central, coastal, and southern California. SCE is a wholly-owned subsidiary of Edison International, which is also based in California. Among other NERC registrations, SCE operates as a TOP within CAISO's BA footprint, and has delegated part of its responsibilities as a TOP to CAISO. SCE is also registered as TP, and is responsible for the reliability assessments of the SONGS separation scheme. SCE owns 5,490 circuit miles of transmission lines, including 500, 230, and 161 kV lines. SCE also operates a sub-transmission system of 7,079 circuit miles at the 115, 66, 55, and 33 kV levels. Of the affected entities, SCE is interconnected with APS, IID, and SDG&E at various transmission voltage levels. SCE owns over 5,600 MW of generation, including a majority share in SONGS, and its peak load exceeds 22,000 MW. Along with SONGS staff, SCE is responsible for the safe and reliable operation of the nuclear facility.

Interconnected Operations

The September 8^{th} event exemplifies the interconnected operations of three parallel transmission corridors through which power flows into the area where the blackout occurred. Typically, BAs, through dispatch, balance the flows on these corridors so that no one corridor experiences overloads in an N-1 situation, but this did not happen on September 8^{th}.

The first transmission corridor consists of the 500 kV H-NG, which is one of several transmission lines forming Path 49 ("East of River"). Along with two 500 kV lines, one from North Gila to Imperial Valley and another from Imperial Valley to Miguel, they form the SWPL. The majority of the SWPL is geographically parallel to the United States-Mexico border. The SWPL meets the SDG&E and IID systems at the Imperial Valley substation. This is shown as the "H-NG Corridor" on Figure 3, on the next page.

The second corridor is Path 44, also known as "South of SONGS," operated by CAISO. This corridor includes the five 230 kV lines in the northernmost part of the SDG&E system that connect SDG&E with SCE at SONGS.

The third transmission corridor, shown as the "S Corridor" on Figure 3, consists of lower voltage (230, 161 and 92 kV) facilities operated by IID and WALC in parallel with those of SCE, SDG&E, and APS. The only major interconnection between IID and SDG&E is through the 230 kV "S" Line, which connects the SDG&E/IID jointly-owned Imperial Valley Substation (operated by SDG&E) to IID's El Centro Switching Station. The "S" Line interconnects the southern IID system with SDG&E and APS at Imperial Valley, which is also a terminus for the SWPL segment from Miguel and the SWPL segment from North Gila. WALC is connected to the SCE system and the rest of the Western Interconnection by 161 kV ties at Blythe, to IID by the 161 kV tie between WALC's Knob and IID's Pilot Knob substations, and to APS by a 69 kV tie via Gila at North Gila.

The eastern end of the SWPL, which terminates at APS's Hassayampa hub, is connected to SCE via a 500 kV line that connects APS's Palo Verde and SCE's Devers substations. The northern IID system is connected to SCE's Devers substation via a 230 kV transmission line that connects from Devers to IID's CV substation. These connections, along with SDG&E's connection to SCE via Path 44's terminus at SONGS, make the SWPL, Path 44, and IID's and WALC's systems operate as electrically parallel transmission corridors.

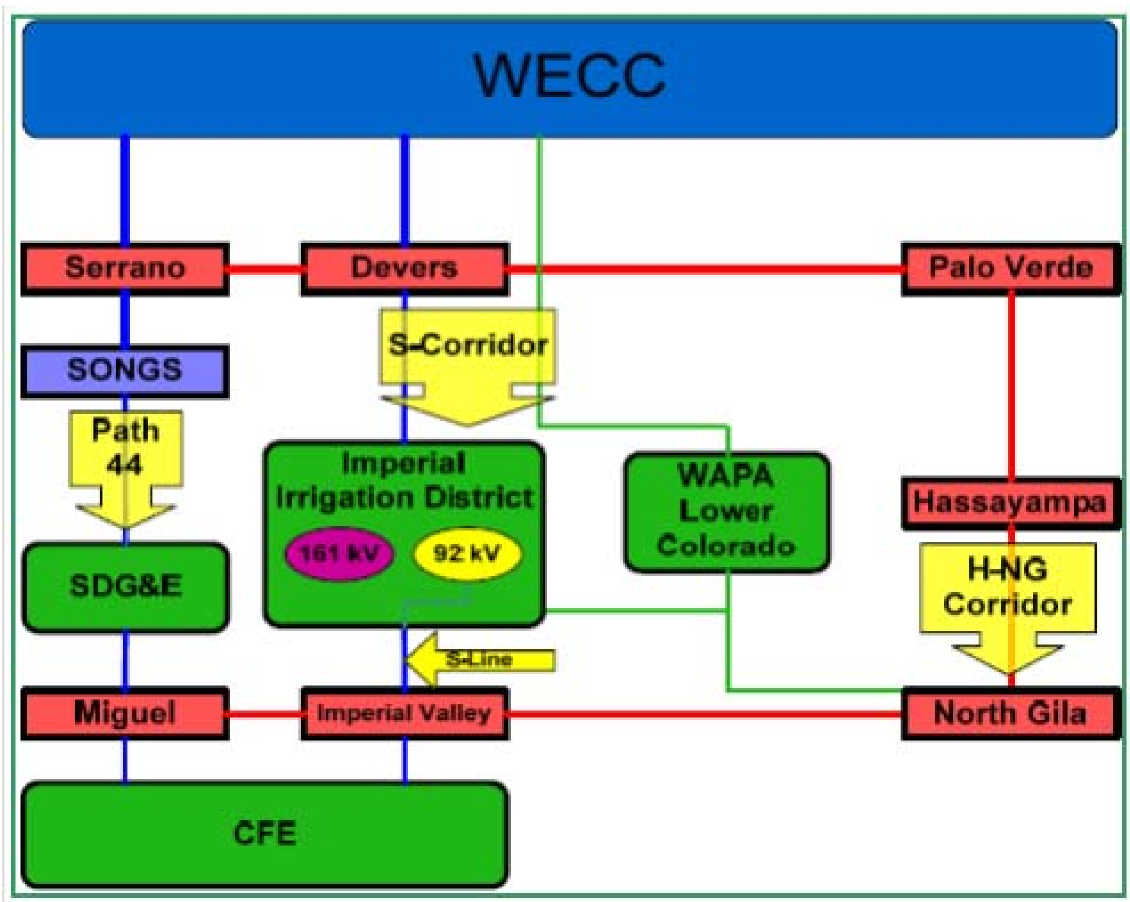

Figure 3

II. SEQUENCE OF EVENTS

The 11 minutes of the disturbance are divided into seven phases, as highlighted in Figure 4, on the next page. This figure displays the progressive loading of the five 230 kV tie lines from SCE north of San Diego that form Path 44. This section describes how the loss of various elements during an 11-minute period combined to exceed the 8,000 amp setting on the SONGS separation scheme. After sustained loading on Path 44 above 8,000 amps, the SONGS separation scheme operated. Once the SONGS separation scheme operated, San Diego and IID, CFE, and Yuma, Arizona, blacked out in less than 30 seconds. This section is divided into subsections for each phase, including the key events during the phase, their causes and effects, and, where relevant, what the affected entities knew and did not know as the events were unfolding. Each section begins with a brief summary. A final subsection describes restoration efforts after the blackout.

All times are in Pacific Daylight Time (PDT) unless otherwise noted. Times are listed to millisecond (three decimal places) or tenth-of-second (decimal place) accuracy when possible. If milliseconds or tenth-of-seconds are not listed, the event is reconciled to the nearest second.

Figure 5 shows all seven phases of the disturbance. The seven phases of the disturbance were,

1. Pre-disturbance conditions,
2. Trip of Hassayampa-North Gila 500 kV Line,
3. Trip of the Coachella Valley 230/92 kV transformer and voltage depression,
4. Trip of Ramon 230/92 kV Transformer and collapse of IID’s Northern 92 kV system,
5. Yuma load pocket separates from IID and WALC,
6. High-speed cascade, Operation of the SONGS separation scheme and islanding of San Diego, IID, CFE, and Yuma, and
7. Collapse of the San Diego/CFE/YUMA island.

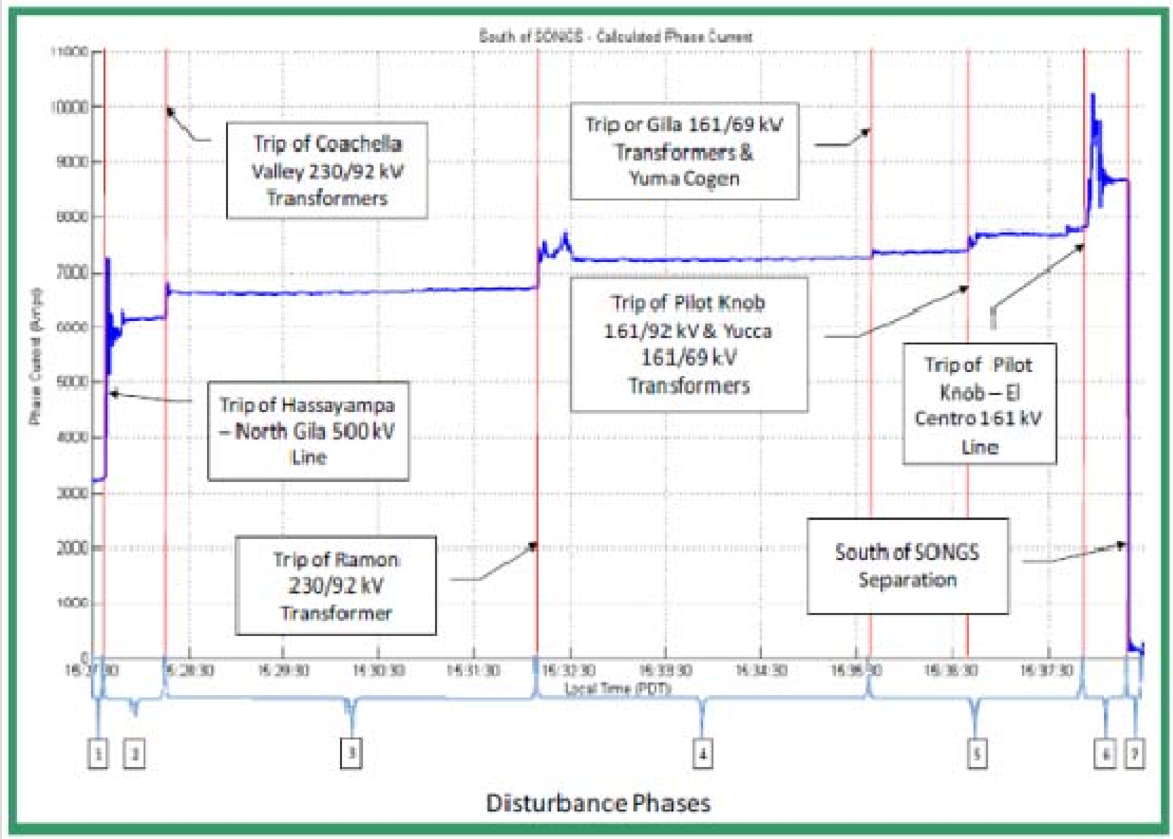

Figure 4

Phase 1: Pre-Disturbance Conditions

Phase 1 Summary:

- Timing: September 8, 2011, before H-NG trips at 15:27:39
- A hot, shoulder season day with some generation and transmission maintenance outages
- Relatively high loading on some key facilities: H-NG at 78% of its normal rating, CV transformers at 83%
- 44 minutes before loss of H-NG, IID’s RTCA results showed that the N-1 contingency loss of the first CV transformer would result in an overload of the second transformer above its trip point
- An APS technician skipped a critical step in isolating the series capacitor bank at the North Gila substation

September 8, 2011, was a relatively normal, hot day in Arizona, Southern California, and Baja California, Mexico, with heavy power imports into Southern California from Arizona. In fact, imports into Southern California were approximately 2,750 MW, just below the import limit of 2,850 MW. September is generally considered a “shoulder” season, when demand is lower than peak seasons and generation and transmission maintenance outages are scheduled. By September 8th, entities throughout the WECC region, including some of the affected entities, had begun generation and transmission outages for maintenance purposes. For example, on September 8th maintenance outages included over 600 MW of generation in Baja California and two 230 kV transmission lines in SDG&E's territory. However, there were no major forced outages or major planned transmission outages that would result in a reduction of the SOLs in the area.

Disturbance Phases

Pre-Disturbance Conditions in IID

Despite September being considered a shoulder month, temperatures in IID's service territory reached 115F on September 8th. IID's load headed toward near-peak levels of more than 900 MW, which required it to dispatch local combustion turbine generation in accordance with established operating procedures. Prior to the event, loading on IID's CV transformers reached approximately 125 megavolt amperes (MVA) per transformer, which is approximately 83% of the transformers' normal limit. Loading on IID's Ramon transformer was 153 MVA, which is approximately 68% of its normal limit.

IID's "S" Line ties IID to SDG&E, and through SDG&E, to generation in Mexico at La Rosita. It also ties CFE and IID, through SDG&E's La Rosita international transmission line. Before the event, IID was importing power on the "S" Line, and thus power was flowing northward from the jointly owned Imperial Valley substation to IID's El Centro substation. Flows on the "S" Line would reverse multiple times during the event. When power flowed on the "S" Line from south to north, the implication was that IID was supplied radially through SDG&E. Throughout the event, as power flowed from north to south, the implication was that flows intended for SDG&E and/or CFE were moving through IID's system. Eventually, in Phase 6, south to north flows on the "S" Line would activate a RAS that would ultimately trip more than 400 MW of generation at La Rosita and the "S" Line, thereby worsening the loading on Path 44.

Forty-four minutes prior to the loss of H-NG on September 8, 2011, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in an overload of the second transformer above its trip point. The IID operator was not actively monitoring the RTCA results and, therefore, was not alerted to the need to take any corrective actions. At the time of the event, IID operators did not keep the RTCA display visible, and RTCA alarms were not audible. By reducing loading on the CV transformers at this pre-event stage, the operator could have mitigated the severe effects on the transformers that resulted when H-NG tripped. Since the event, IID has required, and now requires, its operators to have RTCA results displayed at all times. The loading on IID's CV transformers was pivotal to this event. Loading on the CV transformers is influenced by: (1) the pre-contingency flow on H-NG; (2) load and generation in

IID's 92 kV network; (3) flow on the "S" Line; and (4) to a lesser extent, generation connected to the Imperial Valley substation.

Area Control Error (ACE)
The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.

Pre-Disturbance Conditions in CFE

At 15:07 CFE's Presidente Juarez Unit 11 tripped, which required CFE to activate its Baja California Control Area contingency reserves to restore its Area Control Error (ACE.) At 15:15 PDT CFE returned its ACE to where it had been before the unit tripped. Although still complying with the spinning reserve requirements, CFE was short on non-spinning reserve, with all of its available resources in use or already deployed.

Pre-Disturbance Focus of WECC RC

Prior to the event, WECC RC operators were monitoring unscheduled flow on several paths in Northern California. WECC RC did not view any of the scheduled transmission or generation outages as significant. As illustrated in Table 1below, two minutes before the event (at 15:25), major paths in the blackout area were operating below their Path ratings:

Table 1

Major Paths in the Blackout Area	Established Path Ratings/Flow Limits	Path Loadings MW and Percent
500 kV H-NG (Part of Corridor 1 into blackout area)	1,800 MW	1,397 MW (78%)
Path 44 (Corridor 2 into blackout area)	2,200 MW	1,302 MW (59%)
230 kV "S" Line (Part of Corridor 3 into blackout area)	239 MW	90 MW (38%)
SDG&E Import SOL	2,850 MW	2,539 MW (89%)
SDG&E to CFE Path 45	800 MW S-N 408 MW N-S	241 MW (60%)

Pre-Disturbance Conditions in APS

APS manages H-NG, a segment of the SWPL. At 13:57:46, the series capacitors at APS's North Gila substation were automatically bypassed due to phase imbalance protection. APS sent a substation technician to perform switching to isolate the capacitor bank. The technician was experienced in switching capacitor banks, having performed switching approximately a dozen times. APS also had a written switching order for the specific H-NG series capacitor bank at North Gila. After the APS system operator and the technician verified that they were working from the same switching order, the operator read steps 6 through 16 of the switching order to the technician. The technician repeated each step after the operator read it, and the operator verified the technician had correctly understood the step. The technician then put a hash mark beside each of steps 6 through 16 to indicate that he was to perform those steps. The technician did not begin to perform any of steps 6 through 16 until after all steps had been verified with the system operator.

A **series capacitor** is a power system device that is connected in series with a transmission line. It increases the transfer capability of the line by reducing the voltage drop across the line and by increasing the reactive power injection into the line to compensate for the reactive power consumption. In simple terms, a 50% series compensated line means it has the equivalent of 50% of the electric distance (or impedance) of the otherwise uncompensated line.

The technician successfully performed step 6, verifying that the capacitor breaker was closed, placing it in "local" and tagging it out with "do not operate" tags. However, because he was preoccupied with obtaining assistance from a maintenance crew to hang grounds for a later step, he accidentally wrote the time that he had completed step 6 on the line for step 8. For several minutes, he had multiple conversations about obtaining assistance to hang the grounds. He then looked back at the switching order to see what step should be performed next. His mistake in writing the time for step 6 on the line for step 8 caused him to pick up with step 9, rather than step 7. Thus, he skipped two steps, one of them the crucial step (step 8) of closing a line switch to place H-NG in parallel with the series capacitor bank. This step would bypass the capacitor bank, resulting in almost zero voltage across the bank and virtually zero current through the bank. Because he skipped step 8, when he began to crank open the hand-operated disconnect switch to isolate the capacitor bank, it began arcing under load. He could not manage to toggle the gearing on the switch to enable its closure, so he stayed under the arcing 500 kV line, determined to crank open the switch far enough to break the arc, thereby preventing additional damage to the equipment.

Figure 5 shows load flows during Phase I.

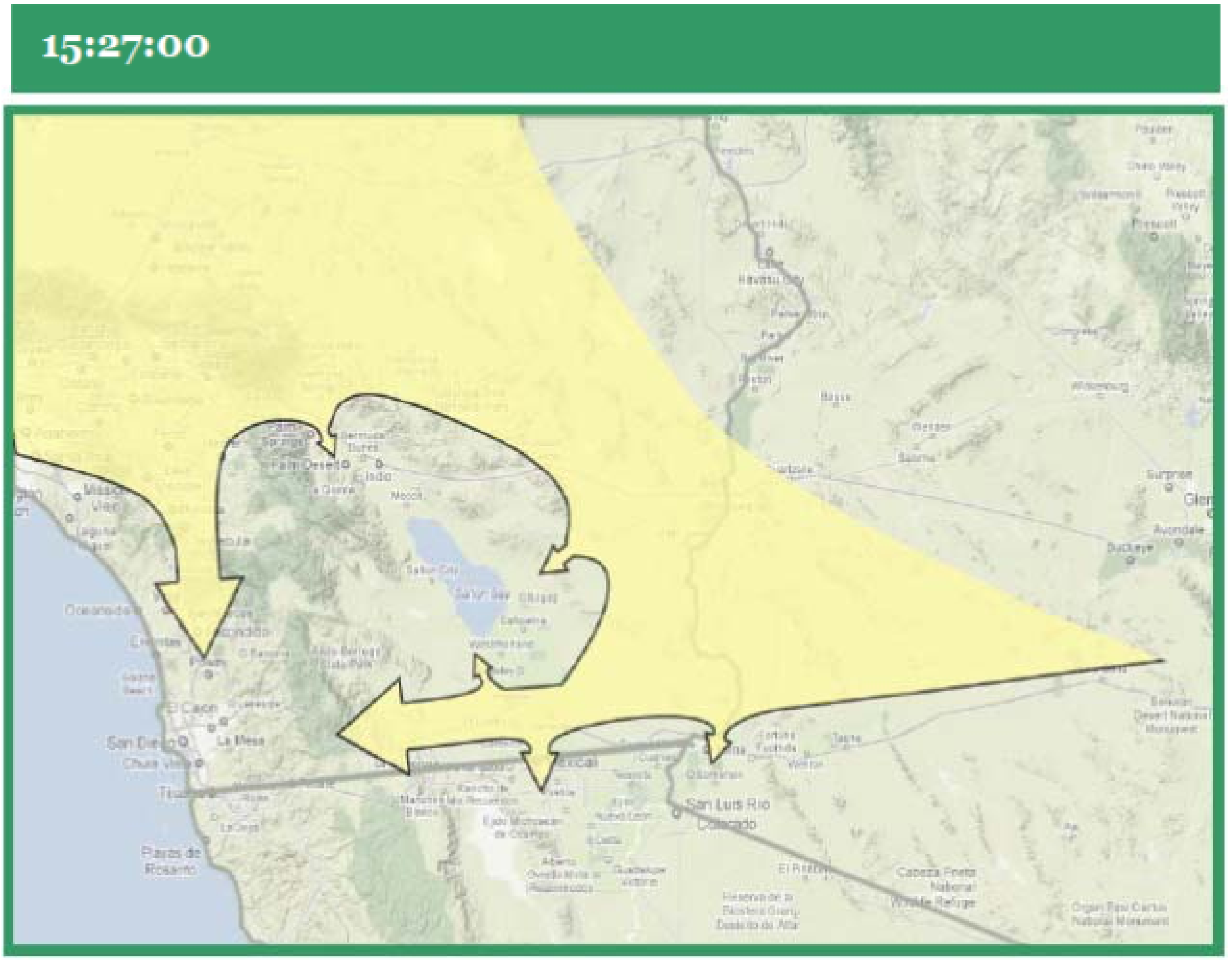

Figure 5

Phase 2: Trip of the Hassayampa-North Gila 500 kV Line

Phase 2 Summary:

- Timing: 15:27:39 to 15:28:16, just before CV transformer No. 2 trips
- H-NG trips due to fault; APS operators believe they will restore it quickly and tell WECC RC
- H-NG flow redistributed to Path 44 (84% increase in flow), IID, and WALC systems
- CV transformers immediately overloaded above their relay setting
- At end of Phase 2, loading on Path 44 at 5,900 out of 8,000 amps needed to initiate SONGS separation scheme

At 15:27:39, the arc that had developed on each phase of the disconnect switch lengthened as the switch continued to open, to the point where two phases came into contact. This caused H-NG to trip to clear this phase-to-phase (A to C) fault. The high-speed protection system correctly detected the fault and tripped the line in 2.6 cycles (43 milliseconds). After discussion with the technician, APS operators erroneously believed that they could return the line to service in approximately minutes, even though they had no situational awareness of a large phase angle difference caused by the outage. More time would have been needed to re-dispatch generation to reduce the phase angle difference to the allowed value. APS system operators informed CAISO, Salt River Project (SRP), and WECC RC that the line would be reclosed quickly, even though they were unaware that this was not possible because of the large phase angle difference that existed between Hassayampa and North Gila. The post-contingency angular difference was beyond the allowed North Gila synch-check relay reclosing angle setting of 60 degrees, and there would not have been adequate generation for re-dispatch to reduce the phase angle difference to within the allowed value. APS operators were only able to see the angular difference on EMS displays after isolating the North Gila capacitor bank and re-energizing H-NG from the Hassayampa substation (before closing at North Gila).

When a line trips, the phase angle at one end of the line may be much larger than the phase angle at the other end. If the difference between the two angles is too great, reclosing the line could cause damage to generators or even system instability.

H-NG, which has a flow limit of 1,800 MW with a 30 minute emergency rating of 2,431 MW, was carrying 1,391 MW flowing from east to west along the SWPL at the time of the trip. As a result of the line trip, flows redistributed across the remaining lines into the San Diego, Imperial Valley, and Yuma areas. The IID and WALC systems, located between the two parallel high voltage Paths, were forced to carry approximately 23% of the flow that had initially been carried by H-NG. The majority of the flow diverted to Path 44, as discussed below.

Immediately after the loss of H-NG, the loading on both of IID's CV transformers increased to 130% of their normal rating and 118.5% of their emergency rating. The time overcurrent relays on the CV transformers picked up because the current flow was above the overcurrent relay setting, and began timing according to their very inverse time delay. The CV transformers would both trip within 40 seconds of the loss of H-NG. At the same time, loading on IID's Ramon 230/92 kV transformer increased to 94% of its normal rating and 85% of its emergency rating. Three seconds after the loss of H-NG, SCADA metering for the CV transformer banks stopped recording accurate readings due to remote terminal unit (RTU) exceeding maximum scale. IID and WECC RC no longer had accurate information about or situational awareness of the loading on these important transformers.

IID also experienced increased loading on several of its 161 kV lines immediately after the loss of H-NG: Blythe-Niland and Knob-Pilot Knob loading increased by 49% and 55%, respectively. Flows on IID's "S" Line reversed from south to north (SDG&E to IID) to north to south (IID to SDG&E) during this phase of the event, indicating that flows intended for SDG&E were being routed through IID's 161 and 92 kV systems. While IID was aware of the flow changes on the "S" Line, it was unable to see the loss of H-NG in real time.

Flows on WALC's Gila 161/69 kV transformers increased from approximately 12 MVA to 60 MVA, still well below their normal limits of 75 MVA each, but indicative of the sudden increase in flows on WALC's system just after the loss of H-NG. WALC also experienced significant voltage drops on its 161 kV system, particularly at Blythe (6.9% drop) and Kofa (6.7% drop) substations, due to the increased flows on that system.

The loss of H-NG interrupted the southern 500 kV path into San Diego. The majority of the flow diverted to the northern entry to SDG&E, Path 44. Flow on Path 44 increased by approximately 84%, from 1,293 MW to 2,362 MW. This flow equates to a tie current of 5,900 amps relative to the 8,000 amps required to initiate the SONGS separation scheme.

After seeing the alarm for the loss of H-NG, the WECC RC operator promptly called the line's operator, APS. APS told WECC RC it could get H-NG restored within minutes. While WECC RC was monitoring Rated Paths, it took no action specific to Path 44, believing it would take five or ten minutes for APS to restore H-NG. As the entire event took only 11 minutes, WECC RC did not issue any directives in connection with the loss of H-NG.

Shortly after H-NG tripped, at 15:27:49, one of the combustion turbines at CFE's Central La Rosita substation tripped while producing 156 MW. This trip may have been triggered by transients caused by the initial fault at North Gila and subsequent trip of H-NG. Loss of this unit further increased the flow on Path 44, raising the current to 6,200 amps out of the 8,000 needed to initiate the SONGS separation scheme. However, the La Rosita trip alone was not significant in causing the cascading that followed. CFE was also unaware in real time that H-NG had tripped. After losing the Central La Rosita unit, CFE was unable to recover its ACE with its own resources, and at 15:30, it requested 158 MW of emergency assistance from CAISO for the remainder of the hour.

Figure 6 shows load flows during Phase 2.

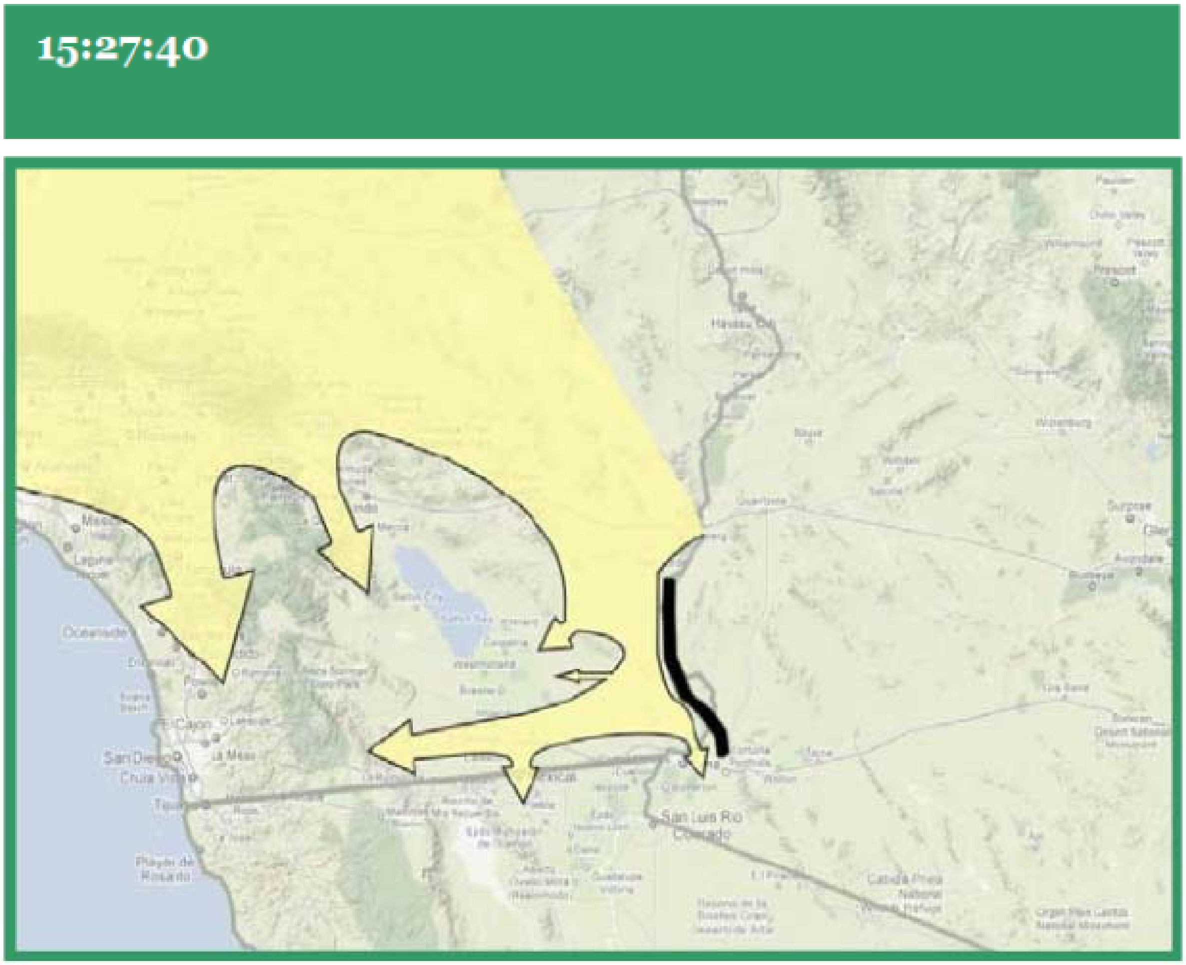

Figure 6

Phase 3: Trip of the Coachella Valley 230/92 kV Transformer and Voltage Depression

Phase 3 Summary:

- Timing: 15:28:16, when CV transformer bank No. 2 tripped, to just before 15:32:10, when Ramon transformer tripped
- Both CV transformers tripped within 40 seconds of H-NG tripping
- IID knew losing both CV transformers would overload Ramon transformer and "S" Line connecting it with SDG&E
- Severe low voltage in WALC's 161 kV system
- At end of Phase 3, loading on Path 44 at 6,700 amps out of 8,000 needed to initiate SONGS separation scheme

At 15:28:16, less than a minute after H-NG tripped, IID's CV transformer bank No. 2 tripped on the 230 kV side. The CV overload protection relays detected an overload immediately after H-NG was lost. The overloads were caused by through-flows on IID's 92 and 161 kV systems which parallel APS's 500 kV system. The normal ratings for these transformers are 150 MVA, but immediately after H-NG tripped, each CV transformer was carrying more than 191 MVA. The relays were set to trip at approximately 127% of the transformers' normal ratings, or 191.2 MVA at nominal voltage. The inverse time relays took 37.5 seconds to trip bank No. 2 and 38.2 seconds to trip bank No. 1. Thus, CV bank No. 1 tripped only 677 milliseconds after bank No. 2, again on the 230 kV side. Although the primary winding or high side voltages of the CV transformers are 230 kV, the banks were not considered as elements of the BES because their secondary winding or low side voltages are below 100 kV. Because these transformers and the underlying 92 kV system were not classified as elements of the BES, IID, neighboring TOPs, and WECC RC did not assess the impact of critical external contingencies on overloading the CV banks, the effect of losing the CV banks and the subsequent impact on the Ramon bank, and, finally their overall adverse effect on BPS reliability.

IID was aware of the potential for local cascading if the CV transformers tripped. IID's next-day plan for September 8, 2011, which was not based on updated studies, indicated that if both CV transformers tripped the Ramon 230/92 kV transformer would trip and the "S" Line tie with SDG&E would overload to 109% of its normal rating. The next-day plan also indicated that this overloading, in turn, would result in tripping generation because the "S" Line RAS trips generation supplied to Imperial Valley when the "S" Line loads to 108% of its normal rating. IID's next-day mitigation plan for loss of the CV transformers required starting turbines at Coachella and Niland and asking CAISO to re-dispatch generation to relieve the "S" Line. This was a post-contingency mitigation plan. But after the event, IID's operator admitted that if the CV transformers tripped on overload, he would have "very little time to mitigate the Ramon [transformer], if at all." Even the quickest-starting turbines take about 10 minutes to start and ramp to full load, but IID effectively had only four minutes before the Ramon transformer would trip, after the loss of the CV transformers.

The loss of the CV banks caused flows on the "S" Line between SDG&E and IID to again reverse direction. Because its load exceeded internal generation, IID began pulling power from SCE through SDG&E due to the loss of key facilities in IID's northern system. The tripping of the second CV bank also open-ended the Coachella Valley-Ramon 230 kV "KS" Line (at CV), which was carrying about 41 MVA. This further increased loading on the Mirage-Ramon 230 kV line and through-flow from IID's 230 kV collector system through Devers, but had little effect on the overall disturbance. By 15:31:35, IID's operators switched in 92 kV capacitor banks at Avenue 42, Avenue 58, and Highline due to low voltage.

The loss of IID's two CV transformers caused the aggregate current on Path 44 to increase from 6,200 amps to 6,600 of the 8,000 amps necessary to trigger the SONGS separation scheme. However, by the end of this Phase aggregate Path 44 current reached 6,700 amps.

The loss of the CV banks caused a severe voltage depression on the WALC 161 kV system south of Blythe. During this period, loads in that area (largely irrigation pumps) were highly susceptible to motor stalling, which can create additional reactive demand and exacerbate transmission loading, both of which contribute to additional voltage decline. At 15:28:18, the Blythe 161 kV bus alarmed at 142 kV (0.882 per unit). WALC continued to experience severe low voltage on its 161 kV system until the "S" Line tripped at 15:38:02.4.

On September 8, 2011, CAISO had partial visibility of IID's system, but could not see that the CV banks had tripped. Prior to the event CAISO and IID had been working together to increase their mutual visibility and those efforts are continuing. Currently, CAISO receives loading data from the 230 kV side of the CV transformers.

Despite the fact that it did not consider the CV banks to be part of the BES, WECC RC does observe much of IID's 92 kV system in real time, including the CV banks. The WECC RC operator did notice the CV transformers trip, but he was focused on when APS would return H-NG to service.

Figure 7 shows the load flows during Phase 3.

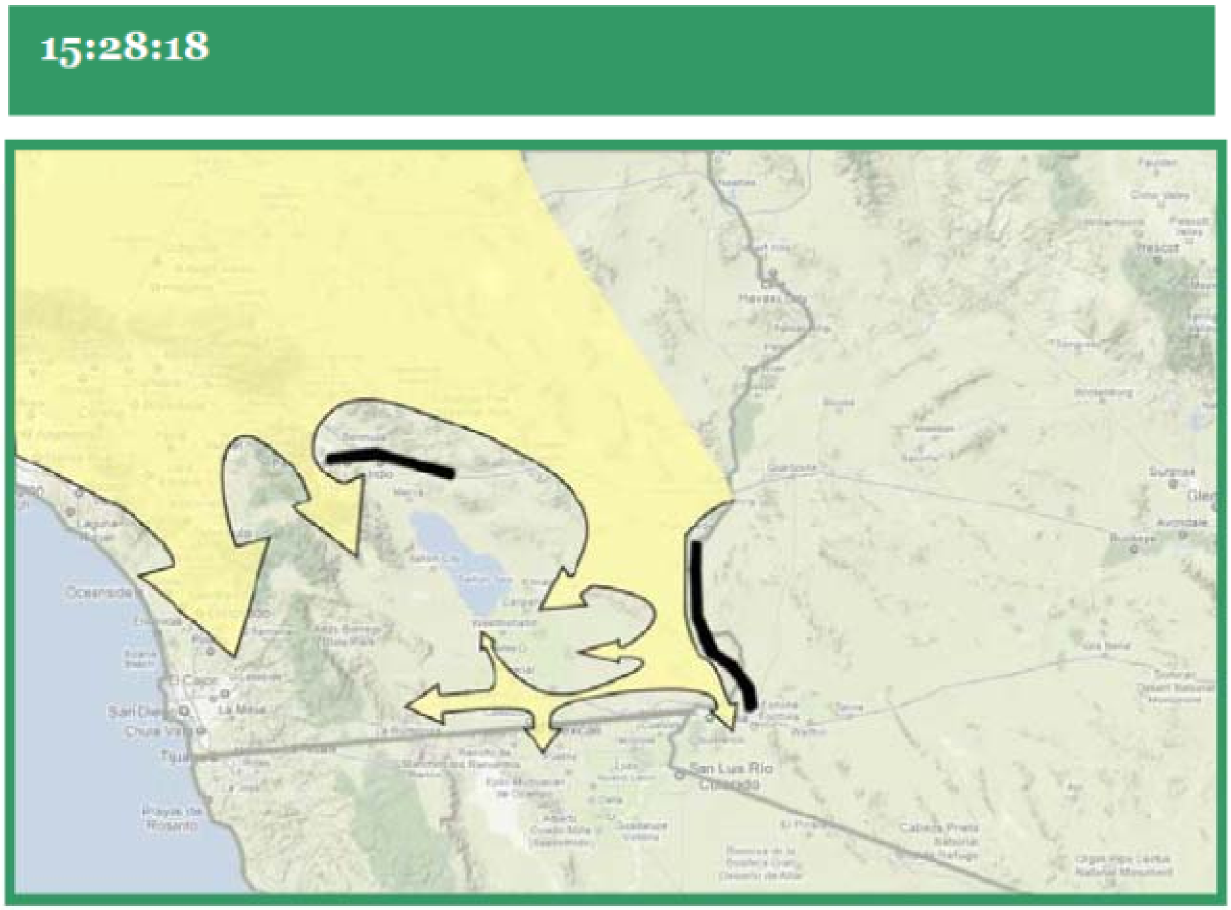

Figure 7

Phase 4: Trip of Ramon 230/92 kV Transformer and Collapse of IID's Northern 92 kV System

Phase 4 Summary:

- Timing: 15:32:10 to just before 15:35:40
- IID's Ramon 230/92 transformer tripped at 15:32:10, was set for 207% of its normal rating instead of its design setting of 120%, which allowed it to last approximately four minutes longer than CV transformers
- IID experienced undervoltage load shedding, generation and transmission line loss in its 92 kV system
- Path 44 loading increased from approximately 6,700 amps, to as high as 7,800 amps, and ended at around 7,200 amps (out of 8,000 needed to initiate the SONGS separation scheme)

At 15:32:10.621, less than five minutes after the trip of H-NG, IID's Ramon 230/92 kV transformer tripped on the 92 kV side. The normal rating for this transformer was 225 MVA, and its relays were set to trip above 207% of its normal rating, or 466 MVA. Before it tripped, the SCADA metering for the Ramon bank had stopped recording accurate readings due to RTUs exceeding maximum scale, just as for the CV banks. Following the loss of the CV transformers, the inverse time relays took less than four minutes to trip the Ramon transformer. IID had intended to set the Ramon transformer to trip at 120% of its normal rating. Had it been set at this level, the Ramon transformer would have tripped almost immediately after the loss of the CV transformers, approximately four minutes earlier than the time of its actual trip. IID believed that the Ramon transformer would overload beyond the trip point upon the loss of both CV transformers. Its next-day plan noted, “the Ramon Bank #1 transformer will overload and relay out of service because the overcurrent settings are set to trip at 120%.” IID’s next-day plan relied on a post-contingency operating philosophy of starting the Coachella Gas Turbines to mitigate overloads following the loss of the CV transformers, but the plan was unrealistic as IID would not have had time to start any additional generation between the loss of the CV transformer banks and the loss of the Ramon transformer.

Within less than one second after the loss of the Ramon transformer, automatic distribution undervoltage protection in IID’s northern 92 kV system began tripping distribution feeders and shedding load. From 15:32:11 to 15:33:46, 444 MW of IID’s load tripped, with nearly half of the load being shed within 10 seconds of the Ramon transformer tripping. The severe voltage depression following the loss of the Ramon transformer appears to have prompted a local voltage collapse within IID’s northern 92 kV system, evidenced by both the steep drop-off in voltage as well as a sharp rise in reactive power flow due to motor stalling.

The loss of IID’s northern resources and subsequent system response caused IID to lose multiple generators connected to its 92 kV system, including IID’s Niland Gas Turbine 2 (generating 45 MW), IID’s CV Gas Turbine 4 (generating 20 MW), independent power producer Colmac’s unit (generating 46 MW), and IID’s Drop 4 Unit 2 Hydro Generator (generating 10.3 MW).

IID also began losing transmission lines. The Blythe-Niland 161 kV “F” Line, which saw increased loading during Phase 2, tripped at 15:32:13 (approximately 3 seconds after loss of the Ramon banks). Its normal rating was 165 MVA, and it was set to trip at 129% of the normal rating (212 MVA at nominal voltage) with a 3-second time delay.46 The Niland-CV 161 kV “N” Line, carrying 83 MVA, tripped approximately 2 seconds later at 15:32:15.29 due to Zone 3 distance protection.

A **distance relay** is a relay that compares observed voltage and current on a line and operates when that ratio is below its pre-set value. Zone 3 relays are typically set to protect against faults that are more than one substation away from the observed line as backup protection. An appropriate time delay should be set in the relay to give the remote station relays the opportunity to operate and isolate the minimum amount of equipment necessary to clear the fault.

In WALC's territory, the Blythe-Goldmine-Knob and Parker-Kofa 161 kV lines overloaded approximately four seconds after the Ramon transformer tripped, at 15:32:14, but did not trip. These lines each had a normal rating of 167 MVA, but were loaded to 177 MVA. Power flows redistributed through the Parker and Blythe areas after IID lost the Blythe-Niland line. WALC took some actions in an attempt to arrest the voltage depression it was experiencing, including a directive to start hydropower generation units Parker 3 and 4 for voltage support at 15:34:07. At the time, Parker area voltage was at 150 kV (0.932 per unit). WALC also switched in shunt capacitors on the 69 kV system at Gila and Kofa. At the time, voltage at Gila was at 65.5 kV (0.906 per unit) while Kofa was at 59 kV (0.86 per unit).

CAISO attempted to bring on generation through its exceptional dispatch process to bring Path 44 back within its limit of 2,500 MW, anticipating that it had 30 minutes to do so. At 15:35, it dispatched the Larkspur No. 2 peaking unit (rated 50 MW) within San Diego, which has a 20-minute start-up time. Also at this time, APS began taking steps to restore H-NG by completing the bypass of the series capacitor bank.

During Phase 4, aggregate loading on the South of SONGS 230 kV transmission lines increased from approximately 6,700 amps to as high as 7,800 amps. The loading settled around 7,200 amps and remained there for the rest of Phase 4.

Figure 8 shows the load flows during Phase 4.

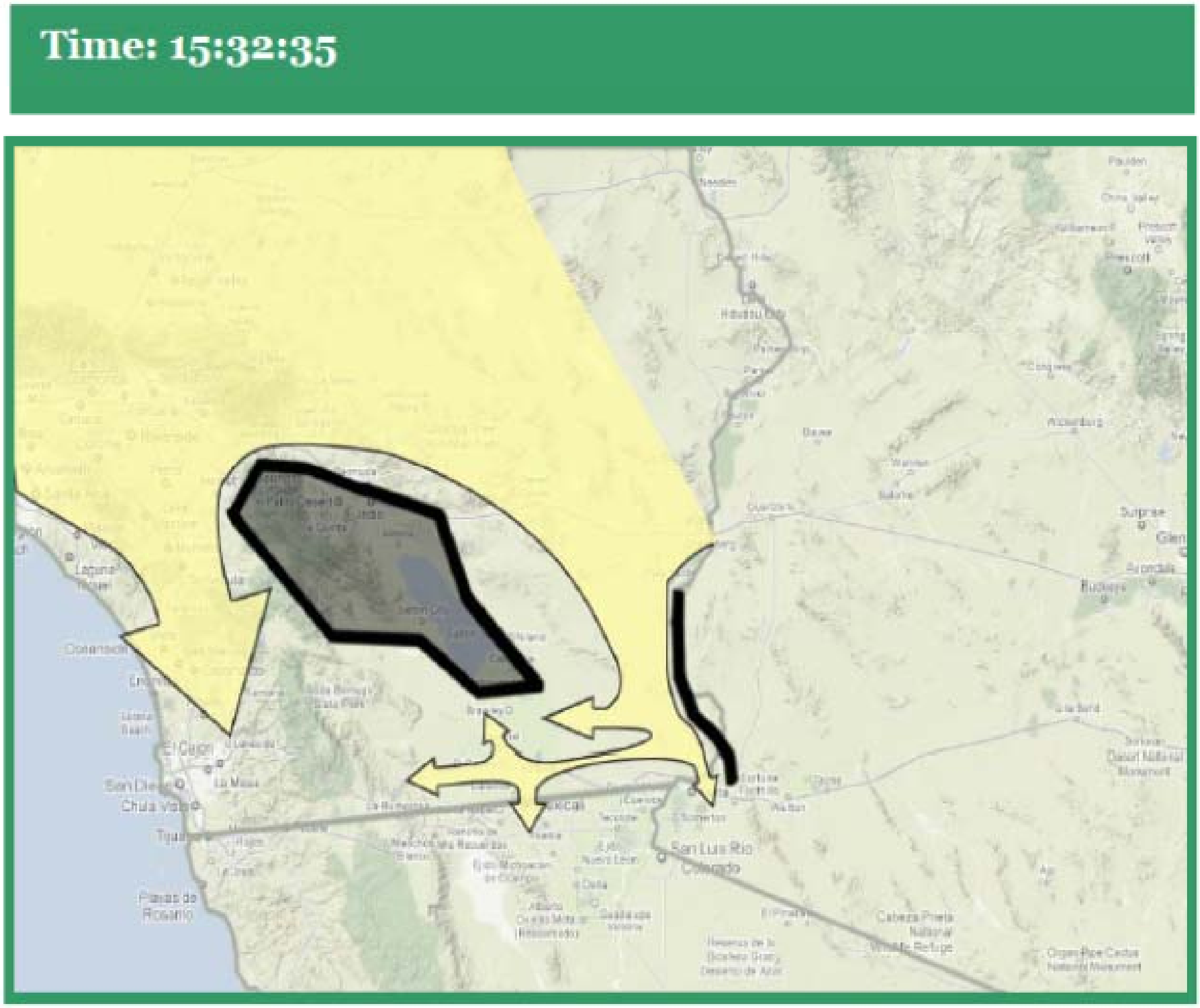

Figure 8

Phase 5: Yuma Load Pocket Separates from IID and WALC

Phase 5 Summary:

- Timing: 15:35:40 to just before 15:37:55
- The Gila and Yucca transformers tripped, isolating the Yuma load pocket to a single tie with SDG&E
- Path 44 loading increased from 7,200 to 7,400 amps after Gila transformer tripped, and ended at 7,800 amps after loss of the Yucca transformers and YCA generator (very close to the 8,000 amps needed to initiate the SONGS separation scheme)

At 15:35:40, approximately eight minutes after H-NG tripped, WALC's Gila 161/69 kV transformers tripped due to time-overcurrent protection. The two transformers are each rated 75 MVA, but the 69 kV bus section that connects the transformers to the rest of the 69 kV substation is rated 1,200 amps (143 MVA at nominal voltage), and the overcurrent protection is set accordingly at 1,200 amps. The bus was carrying 1,312 amps at the time of the trip.

One minute later, at 15:36:40, the Yucca 161/69 kV transformers 1 and 2 tripped when their common 69 kV breaker tripped due to overload protection. Bank No. 1 is owned by IID and is rated 73 MVA, and bank No. 2 is owned by APS and is rated 75 MVA. The IID Yucca generator and four out of the six APS combustion turbines connected to APS's 69 kV system were offline at the time of the event, as was the IID GT21 combustion turbine on the 161 KV side. These generators may have supported load in the area had they been in service. Almost immediately, the Pilot Knob breaker on the Pilot Knob-Yucca 161 kV "AX" transmission line, which is effectively the 161 kV breaker for the Yucca 161/69 kV transformers, received a direct transfer trip from the Yucca transformer overload protection, thereby tripping the AX Line. As a result of the loss of the Yucca and Gila transformers, the Yuma load pocket was isolated to only one tie to the SDG&E system, causing loading on each N. Gila 500/69 kV transformer bank to increase from 57 MVA to 164 MVA.

Less than one second after the Yucca transformers and AX Line tripped, at 15:35:40, the Yuma Cogeneration Associates (YCA) combined cycle plant on the Yuma 69 kV system tripped. The combustion turbine is rated at 35 MW and the heat recovery unit is rated at 17 MW, totaling 52 MW. It appears that both units were fully loaded at the time of the trip. The cause of the trip is unknown, but the loss of the YCA unit hastened the collapse of the Yuma load pocket.

Approximately one minute later, at 15:37:41, a common 161 kV breaker tripped IID's Pilot Knob 161/92 kV transformers Nos. 2 and 5 for No. 2 overload protection. The overload protection was set to trip the banks at 121% of the normal rating (37.5 MVA at nominal voltage).

At WALC's request, between 15:36:48 and 15:36:52, SCE directed Metropolitan Water District operators to drop 80 MW of pumping load attached to the Gene substation (near Parker) to improve 230 kV voltage support at Parker in an attempt to arrest declining voltages.

As it had done during Phase 4, CAISO ordered exceptional dispatch to bring Path 44 below its 2,500 MW limit. At 15:36:00, CAISO called SCE and ordered an exceptional dispatch of Larkspur Peaking Unit No. 1 (rated 50 MW), and Kearny GT2 and GT3 (each rated 59 MW) to go to full load. The Larkspur unit takes 20 minutes to start, and the Kearny units are 10-minute "quick start" peaking generators. All of these units were offline at the time, and they were unable to come online before the system collapsed.

The tripping of the Gila 161/69 kV transformers caused the aggregate loading on Path 44 to increase from approximately 7,200 amps to approximately 7,400 amps, out of the 8,000 amps necessary to initiate the SONGS separation scheme. After the loss of the Yucca 161/69 kV transformers, the YCA plant, and the Pilot Knob 161/92 kV transformers, the loading further increased to approximately 7,800 amps.

Figure 9 shows the load flows during Phase 5.

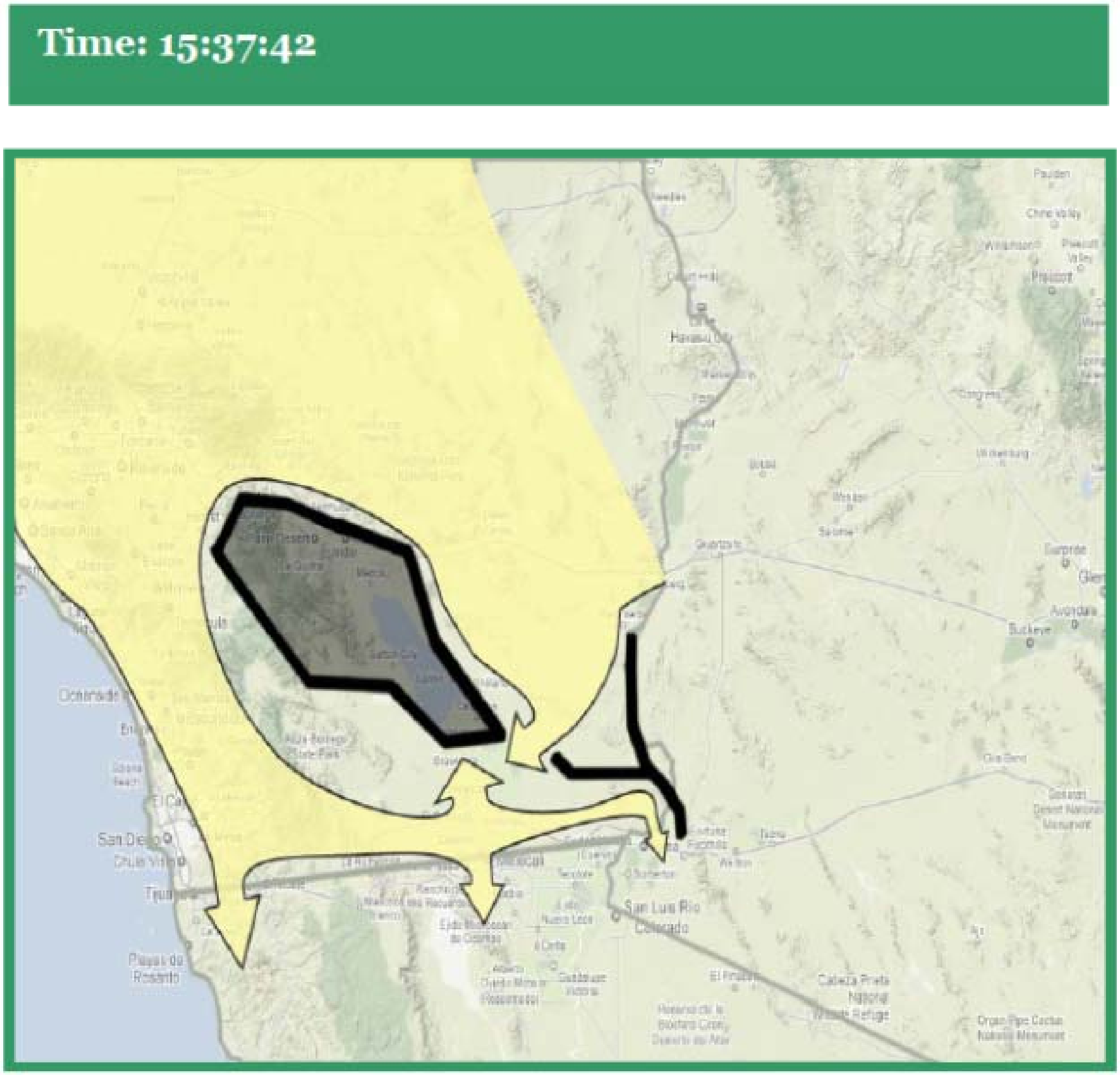

Figure 9

Phase 6: High-Speed Cascade, Operation of the SONGS Separation Scheme and Islanding of San Diego, IID, CFE, and Yuma

Phase 6 Summary:

- Timing: 15:37:55 to 15:38:21.2
- IID's El Centro-Pilot Knob line tripped, forcing all of IID's southern 92 kV system to draw from SDG&E via the "S" Line
- "S" Line RAS operates, tripping generation at Imperial Valley and worsening the loading on Path 44
- "S" Line RAS trips "S" Line, isolating IID from SDG&E
- Path 44 exceeds trip point of 8,000 amps, to as high as 9,500 amps
- SONGS separation scheme operates and creates SDG&E/CFE/Yuma island

When the El Centro-Pilot Knob 161 kV line tripped at 15:37:55 (10 minutes after loss of H-NG), it isolated the southern IID 92 kV system onto a single transmission line from SDG&E: the "S" Line. Forcing all of the remaining load in IID to draw through the SDG&E system pushed the aggregate current on Path 44 to 8,400 amps, well above the trip point of 8,000 amps. If the aggregate current on Path 44 remained above 8,000 amps, the definite minimum time relay would initiate the SONGS separation scheme to separate SDG&E from SCE at SONGS.

IID's El Centro-Pilot Knob 161 kV line open-ended at El Centro when a 161 kV breaker at El Centro tripped on Zone 3 relay protection with a one second delay. The apparent impedance detected on the Zone 3 relay at El Centro was hovering near its trip zone immediately following the Pilot Knob 161/92 kV transformer trips (12 seconds earlier), but did not cross into the Zone 3 tripping region until this time.

By this time in the event, the South of SONGS lines were San Diego's only source of critical imported generation, and were also keeping IID and CFE's Baja California Control Area from going dark. If the aggregate current was brought below 8,000 amps, the blackout could have been avoided, but at this point no operator action could have occurred quickly enough to save the South of SONGS Path. Had there been formal operating procedures that recognized the need to promptly shed load as the aggregate current approached 8,000, and had operators been trained on the 8,000 amp set point, it is possible that operation of the SONGS separation scheme could have been averted by earlier control actions.

Milliseconds after the loss of IID's El Centro-Pilot Knob 161 kV line, at 15:37:55.890, NextEra's Buck Boulevard combustion turbine generator tripped due to operation of SCE's Blythe Energy RAS, dropping 128 MW of generation. This was caused by a reduction of counter-flows on the Julian Hinds-Mirage 230 kV line that had been created by heavy flows from the Julian Hinds-Eagle Mountain 230 kV line feeding toward the WALC 161 kV system to support the heavy north to south 161 kV flows toward Pilot Knob. When the El Centro-Pilot Knob 161 kV line tripped, those counter-flows disappeared, initiating the RAS operation. The Buck Boulevard heat recovery unit ramped down by 82 MW over the next few minutes. The Buck Boulevard combined cycle plant was generating 409 MW (535 MW rating) at the time the combustion turbine tripped. Tripping the Buck Boulevard generator did not increase loading on Path 44, because it is not located south of Path 44.

Had the "S" Line RAS not operated at all, or only operated to trip the CLR II generators, Path 44 flows would have settled above the 8,000 amp threshold and thus the SONGS separation scheme would still have operated.

Just three seconds after the loss of IID's El Centro-Pilot Knob 161 kV line, at 15:37.58.2, the "S" Line RAS at Imperial Valley Substation initiated the tripping of two combined cycle generators at Central La Rosita in Mexico. The "S" Line RAS currently protects El Centro's 161/92 kV transformer No. 2 by initially tripping a combination of CLR II generators when the flow on the "S" Line exceeds 269 MW flowing northward from SDG&E into IID. Two combustion turbines were loaded to 152 MW (193.5 MW rating), and 153 MW (193.5 MW rating), respectively, and the associated steam heat recovery unit (which also tripped following loss of the turbines) was loaded to 127 MW (159.3 rating), totaling 432 MW of generation.

Loss of the CLR II generation drove the South of SONGS flows from about 8,400 amps to about 9,500 amps, which remained above the 8,000 amp setting of the SONGS separation scheme. The inquiry's simulation showed that had the "S" Line tripped without the "S" Line RAS tripping the CLR II generation, the flow on Path 44 would have fallen below 8,000 amps to settle at an estimated 7,730 amps, and the SONGS separation scheme might not have operated.

Approximately four seconds after the "S" Line RAS tripped the CLR II generators, at 15:38:02.4 the "S" Line RAS tripped the "S" Line itself due to flow above 289 MW toward IID from SDG&E. Tripping of this line created an IID island. IID reported that from 15:37:59 to 15:40:24, 507.85 MW of load tripped on its system, mostly in the southern 92 kV system.

The tripping of the "S" Line meant that IID was no longer pulling power from SDG&E and CFE through Path 44, so the aggregate Path 44 flows decreased from approximately 9,500 amps to approximately 8,700 amps, but were still above the 8,000 amps required to trigger the SONGS separation scheme.

At 15:38:21.2, not quite 11 minutes after H-NG tripped, the SONGS separation scheme operated, reconfiguring the SONGS 230 kV switchyard and isolating the SONGS generators onto the SCE system to the north. This reconfiguration effectively separated all five South of SONGS 230 kV transmission lines from the SONGS units and the SCE system, and separated SDG&E from the rest of the Western Interconnection. Operation of the SONGS separation scheme created an island consisting of the SDG&E system, the remaining Yuma-area load connected through the 500 kV system from Miguel to North Gila, and CFE’s Baja California Control Area.

September 8, 2011, was the first time that the SONGS separation scheme had ever activated, and its effects on neighboring systems had not been studied. Although this sequence of events has focused on how the loss of elements combined over the 11 minutes to exceed the 8,000 amp SONGS separation scheme trigger, in real time, no entity was monitoring that limit or recognized the potential consequences of its operation.

WECC RC, responsible for the reliable operation of the BPS, and with having a wide area view of the BPS, did not have any alarm that would alert operators before operation of the separation scheme. Although WECC RC operators were monitoring the Path limit on Path 44, they were not watching the aggregate flows with respect to the SONGS separation scheme trigger. WECC RC operators noticed the five South of SONGS breakers open after the scheme had already operated.

CAISO, the TOP for SDG&E and SCE, did not have any alarms specifically tied to the operation of the SONGS separation scheme either. CAISO only has alarms for when Path 44 exceeds its Path rating, but had no ability to monitor the SONGS separation scheme, set at 3,100 MW (8,000 amps). After the loss of H-NG, which caused Path 44 to exceed its Path rating, CAISO operators were primarily concerned with returning flows on Path 44 to below the Path rating of 2,500 MW, but believed they had 30 minutes to do so. Unlike Path ratings, the separation scheme would not allow CAISO operators 30 minutes to reduce flows on Path 44. CAISO did attempt to dispatch additional generation within SDG&E to reduce flows on Path 44. The other method to reduce flows would have been to manually shed load in SDG&E in time to prevent operation of the SONGS separation scheme. SDG&E estimates that it could have shed approximately 240 MW in between two and two-and-a-half minutes. However, SDG&E was never instructed to shed load and was unaware of the need to shed load.

Figures 10, 11, and 12 show the conditions during Phase 6.

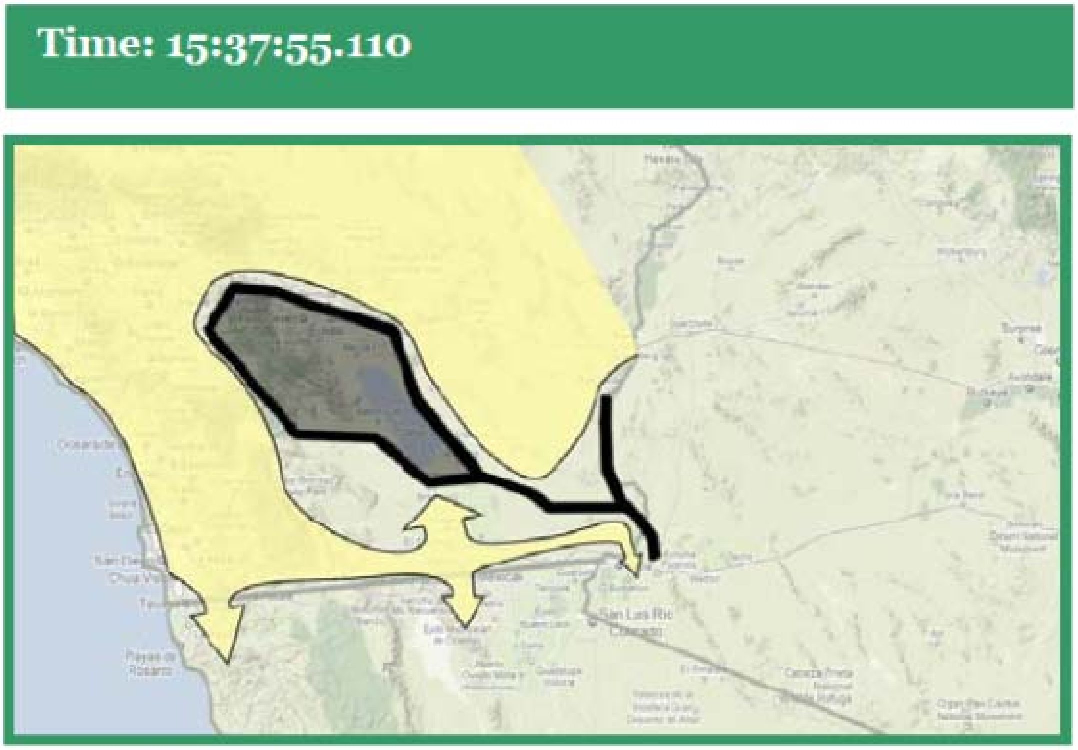

Figure 10

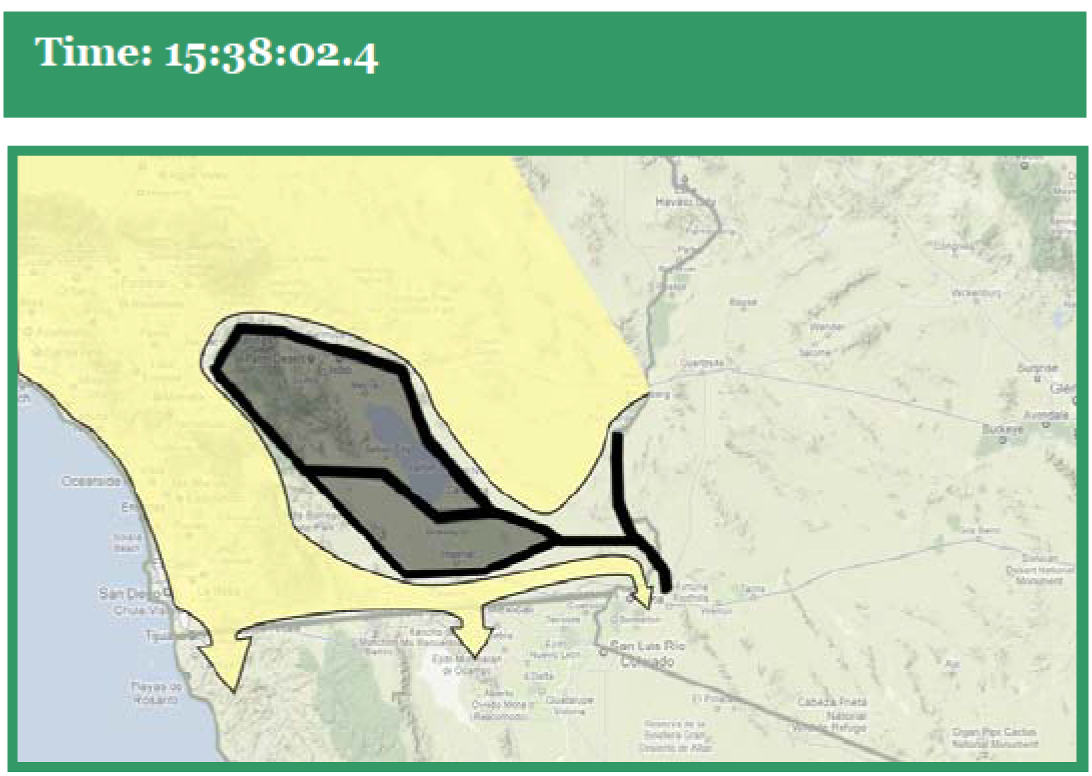

Figure 11

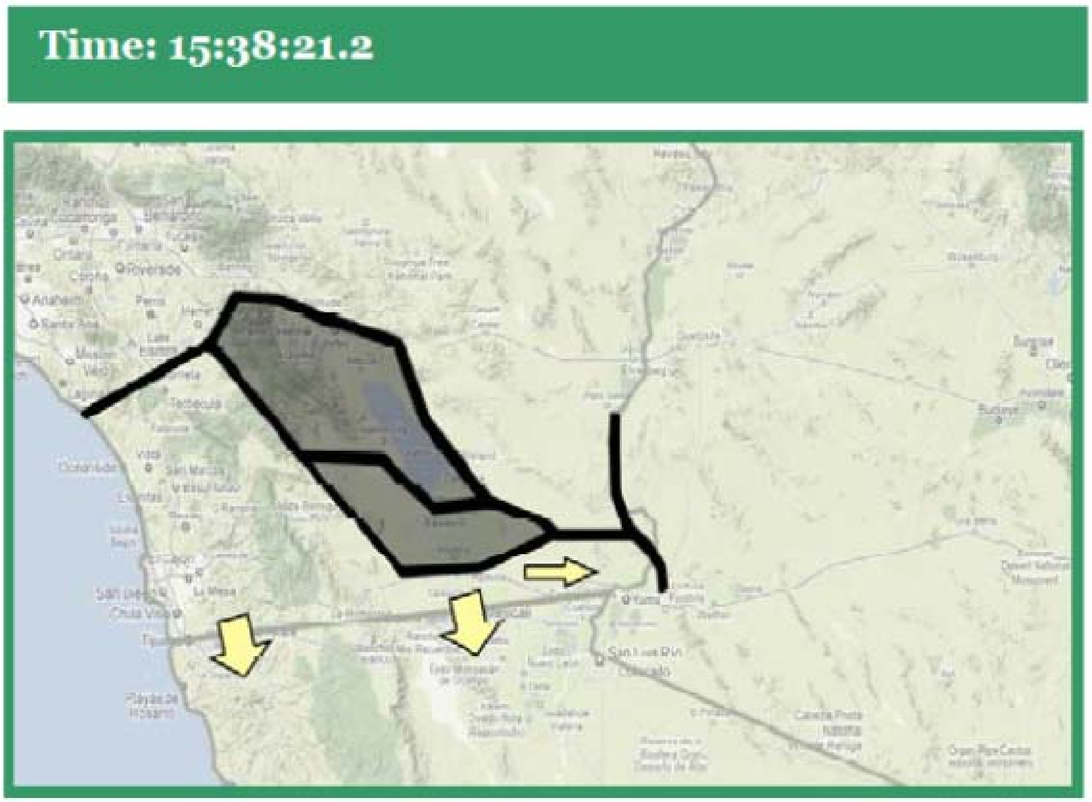

Figure 12

Phase 7: Collapse of the San Diego/CFE/Yuma Island

Phase 7 Summary:

- Timing: Just after 15:38:21.2 to 15:38:38
- Underfrequency Load Shedding (UFLS) was not able to prevent the SDG&E/CFE/Yuma island from collapsing
- SONGS nuclear units shut down even though they remained connected to the SCE side of the SONGS separation scheme

During phase 7 of the event the SDG&E/CFE/Yuma island broke into three separate islands, all of which collapsed due to an imbalance between generation and demand, resulting in severe underfrequency which tripped both loads and generation.

The SDG&E/CFE/Yuma island created by operation of the SONGS separation scheme had a significant imbalance between generation and load from the beginning. As a result, the frequency in the island rapidly declined. By less than a second after the SONGS separation scheme activated (15:38:22), the UFLS programs of SDG&E, APS, and CFE had all began activating within the island. Figure 13, below show the frequency within the island as it collapses.

All steps of the UFLS systems activated and system frequency in the island briefly stalled at approximately 57.2 hertz (Hz). CFE’s UFLS analysis showed 512 MW of load shed by 15:38:21.901.

However, the same analysis showed that three CFE generators, totaling 459 MW, tripped offline beginning at 15:38:21.905, partially negating CFE’s UFLS actions. In addition, a number of smaller generators, totaling about 130 MW, tripped only 0.5 seconds later while CFE was still connected to SDG&E and while SDG&E’s UFLS program was still working to shed load. The net effect of CFE’s UFLS actions and generator trips—512 MW shed by UFLS and 590 MW of tripped generation—was that CFE’s imports from SDG&E increased from approximately 440 MW to approximately 520 MW. This worsened CFE’s system conditions and increased the stress on SDG&E before SDG&E’s underfrequency separation protection systems opened the ties between CFE and SDG&E. SDG&E also had three generators with underfrequency protection that operated at 57.3 Hz, above the frequency at which the system leveled out. Due to these early generation losses, the frequency continued to decline below 57 Hz, which was the underfrequency setting for the majority of generators in the island. Thus, the island blacked out, shortly after separating into three sub-islands.

Frequency, Voltage in the SDG&E/Yuma/CFE Island

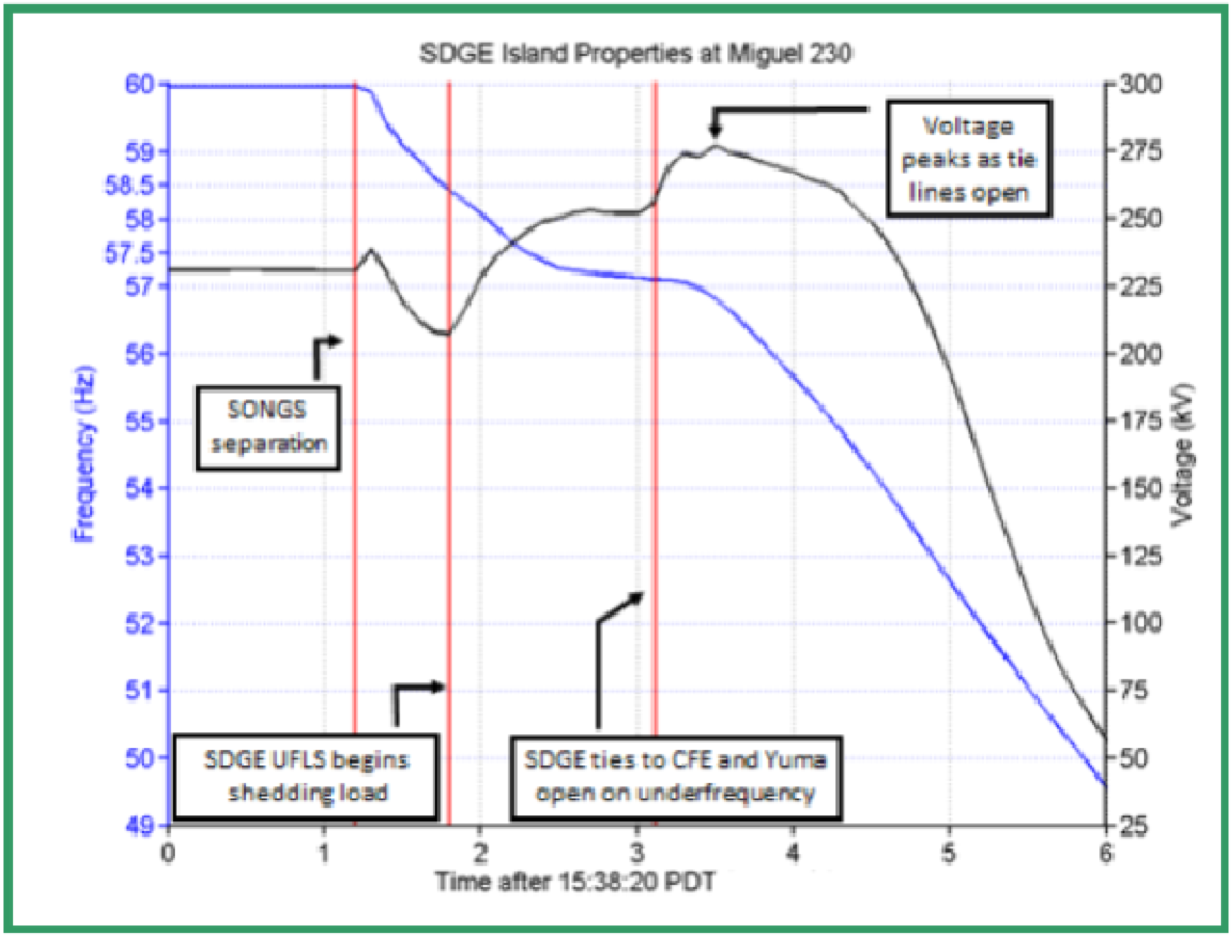

Figure 13

The CFE island separated from SDG&E after their only two remaining ties tripped in rapid succession. At 15:38:22.2, the Otay Mesa-Tijuana 230 kV transmission line open-ended at Tijuana in CFE's territory due to underfrequency protection. Less than a second later, at 15:38:23.13, the Imperial Valley-La Rosita 230 kV transmission line open-ended at Imperial Valley in SDG&E's territory by underfrequency protection. According to CFE, its UFLS program was not designed for the operation of a SDG&E/CFE/Yuma island, but for the operation of a "southern WECC island."

The Yuma island separated from SDG&E at 15:38:23.12, when the Imperial Valley-North Gila 500 kV transmission line tripped by underfrequency protection. APS's UFLS operated on 26 out of the 28 feeders in the Yuma area prior to the loss of the local Yucca steam generators that were on line. However, there was insufficient local generation to stabilize the load pocket in Yuma. At 15:38:38, the Yuma island internal units tripped on underfrequency protection.

At about the same time that it separated from CFE and APS's Yuma pocket, SDG&E lost four generating units, totaling 570 MW, due to the generators' underfrequency protection.

Although the SONGS generators remained connected to the SCE side of the switchyard at SONGS, at about 15:38:27.5, or approximately six seconds after the SONGS separation scheme initiated, the SONGS turbines both experienced a brief acceleration in speed and tripped due to turbine control logic. At the same time, local system frequency at SONGS was observed to spike from 59.974 Hz to 61.203 Hz. After the initial impulse caused by the system separation, the frequency in the main body of the Western Interconnection peaked near 60.170 Hz. The turbine trip initiated a reactor shutdown, and the units began coasting down. A little more than a second later, at 15:38:28.963, SONGS Unit 3 electrically disconnected from the system, and less than three seconds after the reactors shut down, at 15:38:30.209, SONGS Unit 2 electrically disconnected from the system. Loss of the 2,300 MW of SONGS' generation effectively reduced the loss of load for the main body of the Western Interconnection from a 3,400 MW loss to a net 1,100 MW load loss. This made the recovery from the resulting over frequency event much easier. The SONGS generators did not lose offsite power because the SONGS switchyard was still connected to the SCE system.

By 15:38:38, the SDG&E, CFE and Yuma islands had all collapsed, leaving approximately 2.7 million customers without power. Figure 14, 15, and 16 show the conditions during this phase.

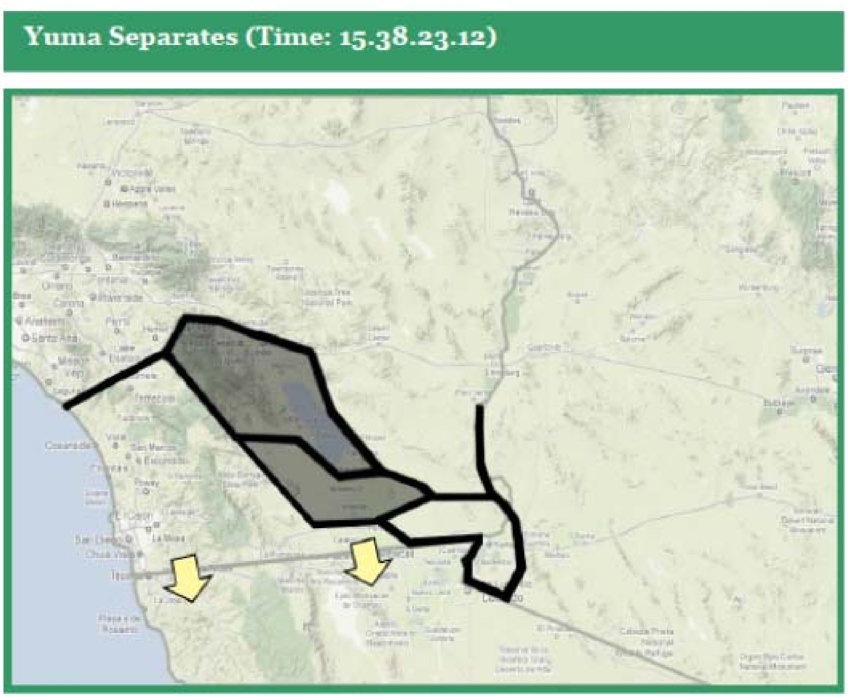

Figure 14

CFE Separates (Time: 15.38.23.13)

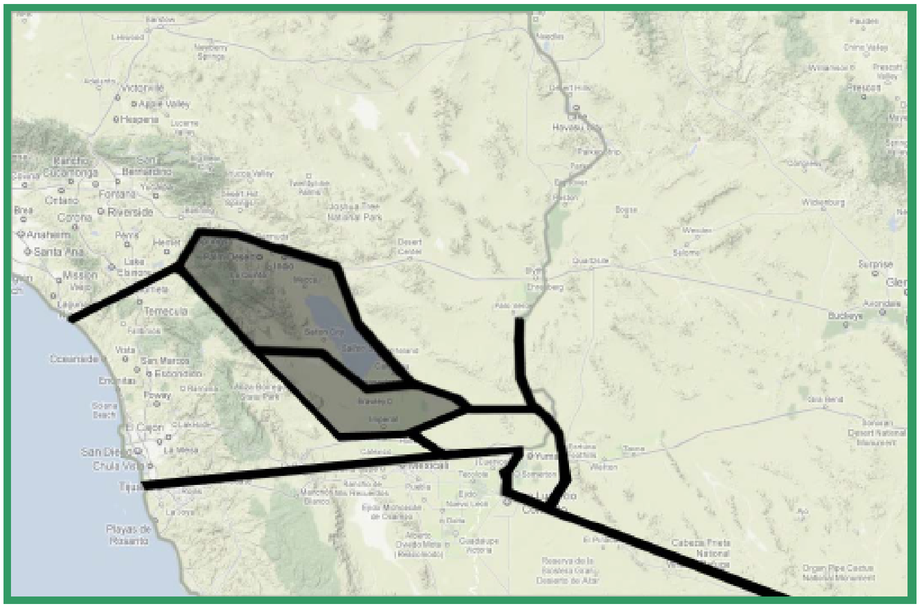

Figure 15

SDG&E, CFE, and Yuma Blackout (by 15.38.30)

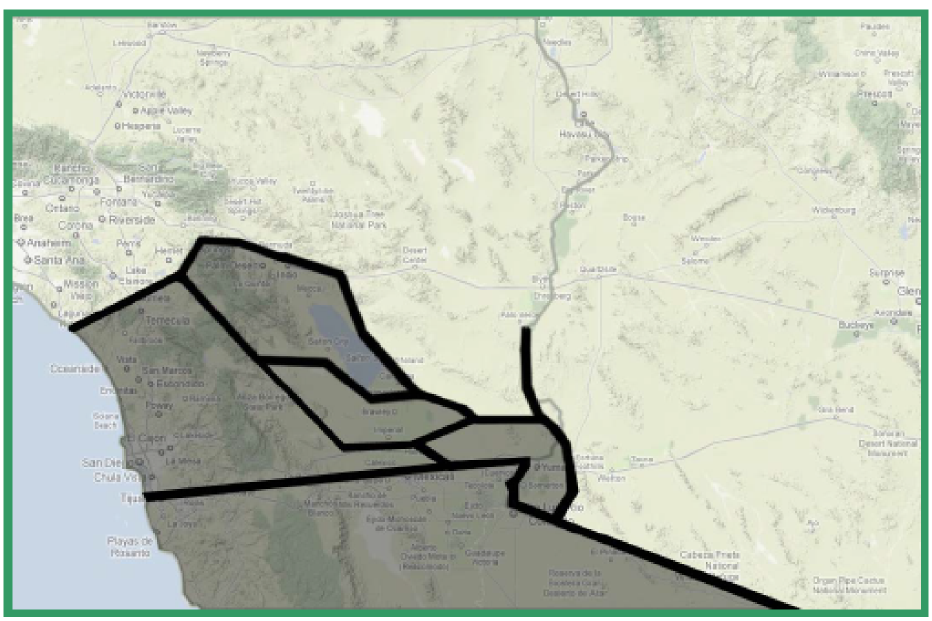

Figure 16

III. System Restoration

None of the affected entities needed to implement black start plans because they all were able to access sources of power from their own or a neighbor's system that was still energized. The restoration process generally proceeded as expected, and some entities restored load more quickly than they had expected. Tables 2, 3, and 4 indicate how long it took the affected entities to fully restore their lost load.

Table 2
Load Restoration Efforts

Entities	Demand Interrupted (MW)	Time Until Demand Fully Restored	Date Restored	100% Demand Restored (Hours)	Number of Customers Affected
SDG&E	4,293	03:23	9/9/2011	12	1.4 million
CFE	2,205	01:37	9/9/2011	10	1.4 million
IID	929	21:40	9/8/2011	6	146,000
APS	389	21:12	9/8/2011	6	70,000
WALC	74	22:23	9/8/2011	6.5	Minimal

Table 3
Generation Restoration Efforts

Entities	Generation Lost (MW)	Time Restored	Date Restored	Time to Restore (Hours)
SCE	2,428	6:33	9/12	87
SDG&E	2,229	6:20	9/10	39
CFE	1,915	23:43	9/10	56
IID	333	20:42	9/8	5
APS	76	20:37	9/8	5

Table 4 **Transmission Restoration Efforts**				
Entities	**Final Transmission Restored (kV)**	**Time Restored**	**Date Restored**	**Time to Restore (Hours)**
IID	230 161	3:37 00:31	9/9 9/9	12 9
SDG&E	500 230	17:36 3:47	9/8 9/9	2 12
APS	500	16:51	9/8	1.5
WALC (transformers only)	161	17:09	9/8	1.5
CFE	230 115	4:03 1:58	9/9 9/9	12.5 10

WECC RC could have taken a more active role in coordinating the restoration efforts. WECC RC has the largest area of visibility and more advanced real-time study tools than the TOPs. During a multi-system restoration, issues are likely to arise between neighboring BAs and TOPs that may require either a neutral decision maker, or rapid technical analysis of unplanned system conditions. WECC RC is uniquely situated to provide such assistance. WECC RC should clarify its role, and the real-time information it can provide, in emergency situations like a multi-system restoration. WECC RC should also specifically address the issue of coordination among other functional entities (like BAs and TOPs) in its operating area, outlining the areas of responsibility during system restoration and other emergencies.

The following incidents that could have benefitted from better WECC RC coordination and assistance in real time:

- A 30-minute debate occurred between SCE, which was attempting to provide cranking power to SDG&E to restore SDG&E's system, and the SONGS operators, about the conditions necessary for resetting the SONGS separation scheme lockout relay.

- Recordings showed a lack of clarity among WECC RC, CAISO, and SDG&E about responsibilities for restoration efforts. Among other things, this resulted in a SONGS operator making a unilateral decision to open a circuit breaker on the line responsible for restoring power to SDG&E's system, leaving the line in a less reliable configuration (connected to a single bus).

Summary

In the course we have looked at the structure of WECC and the affected entities of the September 8, 2011 blackout. The sequence of events of the outage was reviewed in detail from the pre-disturbance conditions to the final collapse of the system.

The next course in this series, Volume II, goes into more detail on the causes of the September 8th outage and reviews the 27 findings and recommendations of the study committee.

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