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Blackout 2011 – Volume II

Instructor: Lee Layton, PE

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5272 Meadow Estates Drive
Fairfax, VA 22030-6658
Phone: 703-988-0088
www.PDHonline.com

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Blackout 2011 - Volume II
Causes, Findings, and Recommendations

Lee Layton, P.E

Table of Contents

Section **Page**

Preface 3

Introduction 4

Planning 10

Situational Awareness 30

System Analysis 40

Summary 55

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 II of a two part series about the September 8th outage. This course 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:

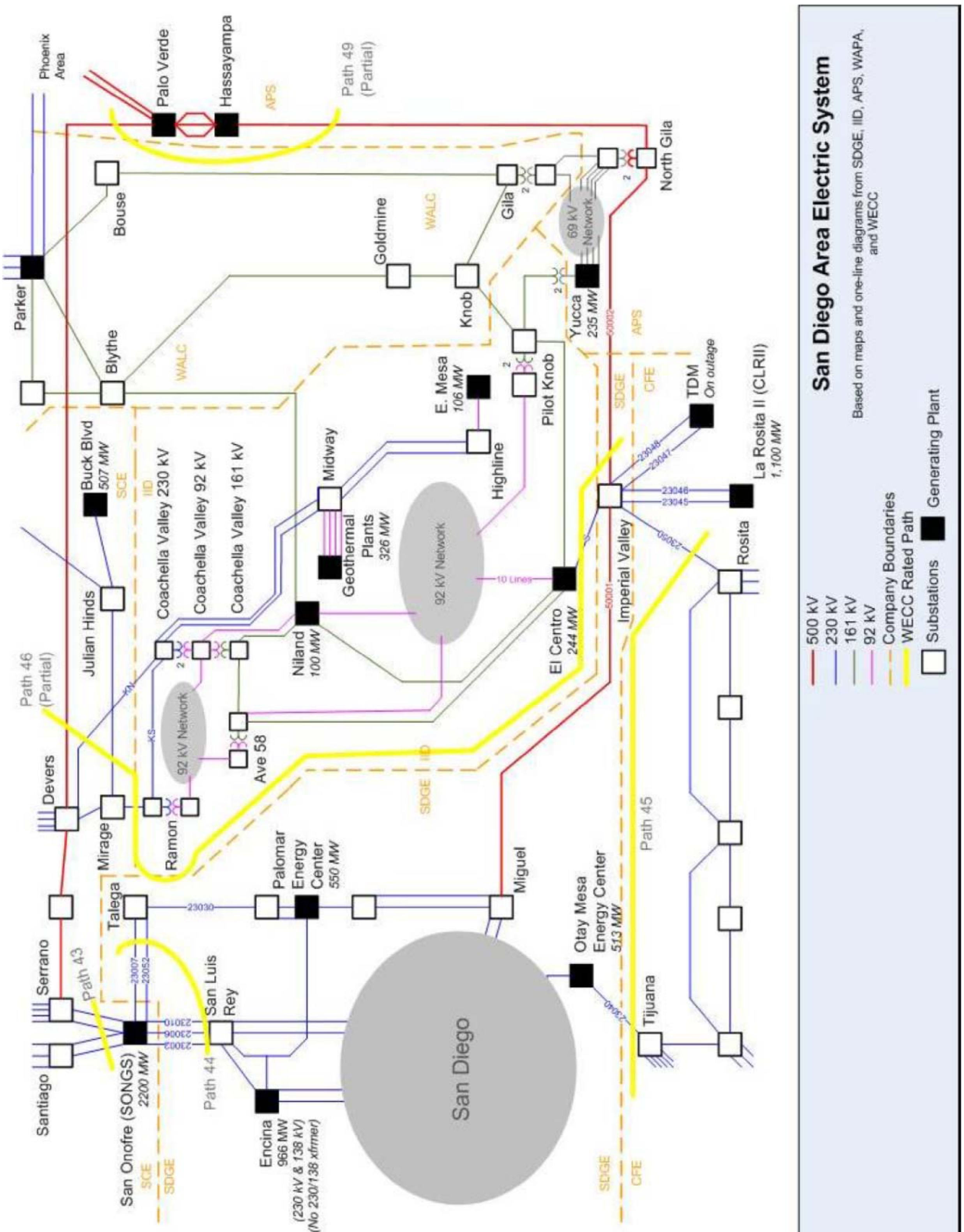
San Diego Area Electric System
Based on maps and one-line diagrams from SDGE, IID, APS, WAPA, and WECC
500 kV
230 kV
161 kV
92 kV
Company Boundaries
WECC Rated Path
Substations
Generating Plant
Phoenix Area
Palo Verde
Hassayampa
APS
Path 49 (Partial)
Parker
Bouse
Blythe
Goldmine
WALC
Gila
North Gila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

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 8th 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 8th 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. Planning

This section discusses the causes, findings and recommendations concerning the planning periods of Next-Day Planning, Seasonal Planning, and Near/Long Term Planning.

Next-Day Planning

Background

TOPs are required to perform next-day studies to identify and plan for potential limitations on their system in the day-ahead timeframe, and to coordinate these studies with their neighboring TOPs. These studies provide a proactive mechanism to ensure that the system can be operated reliably and allow time to develop effective operating solutions. These solutions include, among other things, effective control actions needed to return the system to a secure state in anticipated normal and contingency system conditions. The development of these plans in the day-ahead timeframe is critical because it would be nearly impossible, due to the complexity of the BPS, for control room operators to return the system to a secure operating state under stressed conditions without effective action plans developed in advance. The adequacy of next-day studies depends on how extensively and accurately facilities and next-day system conditions are incorporated into the models used for the studies. This includes consideration of a reasonably accurate, current, and complete list of external contingencies that could impact a TOP's system as well as internal contingencies that could impact external SOLs. Consistency of study inputs among all TOPs and BAs is also critical for reliable operation.

In the analysis of the blackout, it was found that the affected TOPs' and BAs' procedures for conducting next-day studies and models used in these studies vary considerably. As explained more fully below, APS does not conduct next-day studies, relying, instead, on two sets of studies, conducted on a seasonal and annual basis, that consider a list of possible, predetermined contingency scenarios and provide plans to mitigate the contingencies if violated. Meanwhile, IID has a policy of conducting next-day studies each day, but between April and October of 2011, it failed to perform the required studies on a daily basis. All other affected TOPs conduct next-day studies, but they use models that do not adequately reflect next-day operations of facilities in networks external to them. These TOPs' next-day studies also do not consider a full list of internal and external contingencies that could impose limitations on their daily operations or external operations. Moreover, most of these TOPs' next-day studies do not consider the impact of sub-100 kV facilities on BPS reliability, such as the impact of IID's CV transformers.

WECC RC is the highest level of authority responsible for reliable operation of the BPS in the Western Interconnection, with the authority to prevent or mitigate emergency operating conditions in the next-day and real-time timeframes. As such, WECC RC also conducts next-day studies for the entire Western Interconnection and builds its model from the previous day's peak State Estimator case, which includes all facilities operated at 100 kV and above and some sub-100 kV facilities. WECC RC then incorporates forecast information, which typically includes transmission outages as provided by TOPs, generation outages or derates of 50 MW or greater as provided by TOPs, as well as load forecasts, expected net interchange, and unit commitment forecast data from BAs. While WECC RC has a more extensive representation of facilities throughout the WECC footprint in its model than any individual TOP, it does not necessarily monitor or alarm for certain lower voltage facilities and facilities deemed non-BES that can impact BPS reliability. Moreover, because some of the forecasted information can change between the time the TOPs and BAs provide it to WECC RC and the time WECC RC runs its next-day studies, WECC RC's next-day studies might not accurately reflect next-day operations.

The September 8th event exposed four weaknesses with the foregoing procedures for conducting next-day studies in WECC's region. These weaknesses are detailed in the following four findings. A common theme prevails in all four findings: the affected entities do not accurately account for external next-day operating conditions or potential external contingencies that could impact their systems.

Finding 1: Failure to Conduct and Share Next-Day Studies:

Not all of the affected TOPs conduct next-day studies or share them with their neighbors and WECC RC. As a result of failing to exchange studies, on September 8, 2011 TOPs were not alerted to contingencies on neighboring systems that could impact their internal system and the need to plan for such contingencies.

Recommendation 1:

All TOPs should conduct next-day studies and share the results with neighboring TOPs and the RC (before the next day) to ensure that all contingencies that could impact the BPS are studied.

Failure to Conduct Next-Day Studies

APS does not conduct next-day studies. Instead, it relies on two sets of studies, conducted on a seasonal and annual basis, for its daily operations. First, APS uses its summer and winter seasonal studies for the non-WECC Rated Paths within its transmission system. APS performs these studies on a model that it builds from the WECC heavy summer base case. In a coordinated effort with other entities in Arizona, it updates this WECC base case with anticipated loads and resources from the state. APS then adds a detailed representation of the entire state's network, including its own sub-transmission system down to the 12 kV distribution system, to finalize the summer model. To create its winter model, APS modifies the summer model with winter peak conditions throughout Arizona.

Once these summer and winter models are complete, APS studies a set of predetermined contingencies, and relies on the results to determine the response of its transmission system to single and multiple contingencies during peak load conditions with planned outages modeled. The studies' list of contingencies is based on past studies, operating experience, and engineering judgment. The studies also establish mitigating measures for contingencies that do not meet loading or voltage guidelines.

Second, APS relies on a single manual, developed annually, as a guide for its daily operations on four Rated Paths within its system. This manual is the result of studies of possible, predetermined contingencies on Rated Paths. The results and operational instructions in this manual are based on seasonal models that APS develops in coordination with four WECC regional study groups, led by CAISO. CAISO first sends a base case to each study group to update with topology changes for the upcoming season. Individual members of each study group also update the model with details from their systems. CAISO then incorporates all of the updates and stresses key paths in California before sending the model back to the study groups. APS uses this model as a starting point to study the four Rated Paths in its system. APS analyzes the resulting peak-load model using a predetermined set of single and double contingency events that are focused primarily on high-voltage transmission outages to determine required actions to secure the system for the next most critical N-1 event. The manual directs APS to rerate relevant Path(s) and identifies necessary mitigating measures as long as the contingency (or multiple contingency) scenario is included in the manual. The manual, however, may not include a particular contingency (or multiple contingency) scenario, or may not accurately reflect the internal and external system topology for the day in question, resulting in the potential for unforeseen circumstances.

Thus, APS uses seasonal studies for non-Rated Paths and the manual for Rated Paths as tools in the day-ahead timeframe, without any additional analysis to validate that the tools remain valid for the next day's specific configuration and operation, such as transmission or generation outages external to APS's footprint that were not anticipated at the time the base seasonal study was performed. APS maintains that these tools are sufficient for day-ahead purposes because they include the most severe contingencies identified in its system. This viewpoint overlooks the purpose of next-day studies—to plan for next-day operations in light of conditions that change daily. By relying on tools based on studies conducted on a seasonal and annual basis, APS cannot account for all plausible daily scenarios. For typical days that fall within the boundaries of the underlying studies and analysis, APS's tools may be viable. For atypical days where conditions fall outside the studied boundaries, however, this approach may not be adequate. For example, September 8, 2011, was an atypical day not contemplated by APS's manual, as the manual did not account for various generation outages in effect for maintenance.

Between April and October 2011, IID also did not consistently perform adequate next-day analyses for each day. Although IID had a policy of conducting separate next-day analyses for each new day, it failed to consistently perform the required analyses. Specifically, IID produced a document each new day showing various changes in weather, load and generation forecasts, planned facility outages, potential contingency violations, or mitigation measures for identified contingencies, but did not always perform the underlying power flow studies for each day between April and October 2011. On average, between April 2011 and October 2011 IID actually performed a study no more than two times per week. For the other days, IID simply referenced past studies. For example, it appears that IID did not perform a separate, updated study for September 8, 2011, because the power flow study case provided for this day does not match the contingency results included in the daily operations guide for the day. In other words, it appears that for September 8, 2011, IID simply changed the forecasted data without actually performing the next-day study. Instead, IID referenced a previous study. The referenced study, however, was not valid because it did not match the load and generation dispatch data for the day, and there were differences in projected overloads reported as potential contingencies. IID's next-day studies were purportedly reviewed by IID for accuracy, but these discrepancies were not identified. IID discovered this issue during the course of the inquiry and is in the process of implementing corrective actions to ensure accurate next-day analyses are completed in the future.

Finally, the TOPs, including APS said that WECC RC was responsible for conducting next-day studies or that WECC RC should conduct next-day studies that TOPs are currently responsible for conducting. WECC RC's next-day studies for the entire Interconnection, however, are not intended to substitute for the TOPs' next-day studies of their own systems.

Failure to Effectively Share and Coordinate Next-Day Studies

In addition to finding that not all entities conduct next-day studies, there were problems with sharing and coordination among the affected TOPs that do conduct such studies. The affected TOPs do not consistently share their studies with neighboring TOPs, BAs, and the RC. TOPs generally provide studies to WECC RC only if the RC identifies an issue in its study and specifically asks to review a TOP's study. In addition, WECC RC's method of sharing its next-day studies with other entities is not effective. Specifically, WECC RC's practice is to share the results of its next-day studies when conditions warrant, or when it receives a request for a study result. WECC RC posts on a secure Internet portal a list of limitations or SOLs identified by its next-day studies for individual TOPs and BAs to view, but it is up to TOPs and BAs to access this list. Also, this list contains only issues that WECC RC deems significant and does not include basic, next-day operating conditions, such as scheduled outages.

One example of the adverse consequences of these sharing and coordination issues relates to the 600-plus MW of TDM generation that was offline for maintenance on September 8th. The TDM generation outage was included in WECC RC's and CAISO's next-day studies, and posted on CAISO's website, but not incorporated into other entities' next-day models and studies. WECC RC receives outage information from TOPs and BAs through its Coordinated Outage System (COS). While TOPs and BAs submit their own information into COS, they cannot access information submitted by others. IID could have benefitted from knowledge of the TDM outages. The TDM units radially connect to the Imperial Valley substation, jointly owned by IID and SDG&E. If the TDM units had been online, they could have mitigated northern IID overloads on the CV and Ramon transformers that resulted when H-NG tripped. If IID had learned about these outages from WECC RC or CAISO, it could have incorporated the outages in the day-ahead timeframe and dispatched additional generation, or taken other control actions, to compensate for the overloads on its system caused by having these generators offline and the H-NG tripping.

TDM is the generation known as Termoelectrica de Mexicali.

The September 8th event illustrates that conducting next-day studies and sharing the results of such studies are critical to allow TOPs to identify and plan for potential contingencies.

Finding 2: Lack of Updated External Networks in Next-Day Study Models:

When conducting next-day studies, some affected TOPs use models for external networks that are not updated to reflect next-day operating conditions external to their systems, such as generation schedules and transmission outages. As a result, these TOPs' next-day studies do not adequately predict the impact of external contingencies on their systems or internal contingencies on external systems.

Recommendation 2:

TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.

As a starting point for their next-day studies, the affected TOPs use models from either a TOP's seasonal base case or the previous day's EMS model, if available. The seasonal base case represents next-day operating conditions internal to the TOPs' systems, but leaves external networks exactly as they were represented in the WECC seasonal base case. The affected TOPs' EMS models sometimes include only one or two buses outside each TOP's internal footprint. Thus, neither type of day-ahead model contains actual day-ahead forecasts of system conditions external to each TOP's system. For example, leading into September 8th, the affected TOPs had limited knowledge of the current status of transmission facilities, expected generation output, and load predictions outside their footprints. Consequently, their next-day studies could not adequately predict the impact of external contingencies on their systems or of internal contingencies on external systems.

IID's next-day study for September 8th illustrates the adverse effects of not accounting for external next-day planned operations. IID used the WECC heavy summer seasonal base case to model external conditions for its next-day study for September 8th. This base case reflects that most external generation is online to meet summer peak loads. A heavy summer base case does not accurately represent a shoulder season day like September 8th. By September, both generation and transmission maintenance had started.

For example, on September 8th TDM generator units in Mexico, totaling more than 600 MW, were offline for maintenance. These units are external to IID and radially connect to IID's jointly owned Imperial Valley substation. When online, this generation can help to mitigate overloads on the CV and Ramon transformers in IID's system. Because IID relied on a heavy summer seasonal model for external networks and did not incorporate any updates about the TDM generation, its next-day study did not reflect the maintenance outage of these units. With the TDM generation incorrectly represented as being online, IID's next-day study did not correctly identify how much the loss of H-NG would overload IID's transformers in its 92 kV system. In fact, IID's next-day study for September 8, 2011, did not show that the loss of H-NG would overload the CV transformers to their trip point. If IID had learned about the TDM outages (whether from CAISO's website or BY some other method) and incorporated the information into its model, it could have dispatched additional generation, adjusted load, or taken other control actions before the loss of H-NG to mitigate such overloading.

As mentioned above, WECC RC receives next-day data from the entities through interfaces such as the COS. WECC RC is well-situated to facilitate data-sharing among the 37 BAs and 53 TOPs in the WECC footprint. Given the large number of BAs and TOPs in the WECC region, some of which are relatively small in size and resources, central coordination and facilitation may be necessary to ensure that all BAs and TOPs accurately reflect next-day operating conditions external to their system. WECC RC has been working to facilitate data sharing by drafting and circulating a universal non-disclosure agreement.

Finding 3 Sub-100 kV Facilities Not Adequately Considered in Next-Day Studies:

In conducting next-day studies, some affected TOPs focus primarily on the TOPs' internal SOLs and the need to stay within established Rated Path limits, without adequate consideration of some lower voltage facilities. As a result, these TOPs risk overlooking facilities that may become overloaded and impact the reliability of the BPS. Similarly, the RC does not study sub-100 kV facilities that impact BPS reliability unless it has specifically been alerted to issues with such facilities by individual TOPs or the RC has otherwise identified a particular sub-100 kV facility as affecting the BPS.

Recommendation 3:

TOPs and RCs should ensure that their next-day studies include all internal and external facilities (including those below 100 kV) that can impact BPS reliability.

The September 8th event showed that some sub-100 kV facilities can have significant impacts on BPS reliability, such as causing instability or cascading outages. Yet, it appears that these facilities are not adequately considered in the day-ahead timeframe. For example, IID's 92 kV network runs parallel to two major transmission paths: (1) Path 44, which connects to the SWPL via the Palo Verde-Devers 500 kV line (part of Path 49) and runs to the north of IID; and (2) the SWPL, which runs to the south of IID. Given the parallel nature of its system, IID's 92 kV system is forced to carry a significant portion of any east-west power flows whenever segments of Path 44 or the SWPL are out of service.

Because none of the affected TOPs, besides IID, considered IID's 92 kV network in their next-day studies, they were not aware how their internal contingencies could affect IID's 92 kV network, or how an overload on IID's 92 kV network could affect their systems. For example, APS does not routinely study IID's lower voltage facilities, including the CV and Ramon transformers, in the day-ahead timeframe. APS uses seasonal studies and its operations manual as its tools in the day-ahead timeframe. While the model used for the seasonal studies physically has IID's 92 kV network represented, neither the model nor the operations manual are used to consider the next day's specific configuration and operation, such as transmission or generation outages external to APS's footprint that were not anticipated at the time the seasonal study and manual were updated. As a result, APS was not able to predict what occurred on IID's system—increased flows and overloading on its 92 and 161 kV transformers and transmission lines—when H-NG tripped offline. Similarly, affected TOPs other than IID do not consider in their day-ahead planning how the loss of the CV and Ramon transformers, leading to the "S" Line RAS operation, could adversely affect their internal systems. Accordingly, TOPs should revise their next-day study practices to account for all facilities, including those operated below 100 kV, that impact BPS reliability.

WECC RC also did not adequately consider sub-100 kV facilities not identified as BES that can have significant impacts on BPS reliability. While WECC RC does model IID's CV transformers in its next-day studies, prior to September 8, 2011, it did not "flag" them in its studies for active monitoring. This means that WECC RC had data showing that the transformers would overload under certain conditions, but the overloads were not identified by alarms to be seen by RC operators. WECC RC did not actively monitor the CV transformers in its next-day studies because they are below 100 kV and IID had not alerted WECC RC to any issues that would warrant monitoring of the transformers. Given the CV transformers' impact on BPS reliability, WECC RC should actively monitor these transformers.

Finding 4 Flawed Processes for Estimating Scheduled Interchanges:

WECC RC's process for estimating scheduled interchanges is not adequate to ensure that such values are accurately reflected in its next-day studies. As a result, its next-day studies may not accurately predict actual power flows and contingency overloads.

Recommendation 4:

WECC RC should improve its process for predicting interchanges in the day-ahead timeframe.

Interchanges are energy transfers that cross BA Areas. Interchanges can affect flows across transmission systems, so forecasting accurate interchanges is important in the day-ahead timeframe to plan for potential overloading. WECC RC's process for estimating scheduled interchanges is not adequate to ensure that the scheduled interchanges incorporated into its next-day studies are accurate. Under this process, by 10:00 AM each day BAs provide WECC RC with all interchanges they have approved for the next day. The BAs typically submit this information once per day without any subsequent updates. WECC RC then validates these scheduled interchanges by comparing the values with what the BAs provided the prior day and with what WECC RC's state estimator observed in the prior days and weeks.

The accuracy of interchange data in WECC RC's next-day studies could be improved by allowing for updates closer to real time. BAs' interchange data are likely to change after their 10:00 AM submittal to WECC RC. Some BAs have automated systems, which send updates of interchange data to WECC RC. Most BAs submit the data manually, only once at 10:00 AM.

Inclusion of a process or requirement for BAs to update their scheduled interchanges after their 10:00 AM submission would increase the likelihood of accurate interchange data.

The accuracy of interchange data affected WECC RC's next-day study for September 8, 2011. Specifically, the scheduled interchanges reflected in WECC RC's next-day study for September 8, 2011, were not sufficiently accurate to predict that IID's CV 230/92 kV transformers would overload to their trip point upon the loss of H-NG. After the event, WECC RC ran its next-day study using actual interchanges, and found that the CV transformers would overload beyond their tripping threshold upon the loss of H-NG. If WECC RC had used more accurate net interchange data and flagged the CV transformers for monitoring, it could have learned of the issues with these transformers and alerted IID or issued directives for control actions to mitigate the situation, such as increasing generation or shedding load.

Seasonal Planning

Background

Following a set of disturbances in the Western Interconnection during the summer of 1996, WECC established a new seasonal planning structure designed to avert system-wide disturbances while maximizing the commercial availability of transmission capacity. This new structure involved the creation of the Operating Transfer Capability Policy Committee (OTCPC). The purpose of the OTCPC was to provide coordinated standard development and determination of seasonal *Operating Transfer Capabilities* (OTCs), or Operating Transfer Limits, within the Western Interconnection.

Among other things, the OTCPC was designed to be responsible for determining which transmission paths should be studied, facilitating OTC dispute resolution, ensuring that seasonal studies maintain consistent standards and methodologies, and approving seasonal studies of OTC limits. To that end, the OTCPC was charged with reviewing and approving study plans and technical simulation results; developing policies and procedures addressing seasonal OTCs; establishing working groups such as sub-regional study groups and the Operating Procedures Review Group; addressing OTC seams issues between sub-regions; and providing technical guidance.

The seasonal study plans that are reviewed and approved by the OTCPC were created by a set of four sub-regional study groups (sometimes referred to as SRSGs or simply sub-regions). There were four groups: (1) the California/Mexico Operations Study Subcommittee (OSS); (2) the Northwest Operational Planning Study Group (NOPSG); (3) the Rocky Mountain Sub-regional Study Group (RMSG); and (4) the Southwest Area Study Group (SASG). The affected entities were members of two of these groups: the OSS (CAISO, SDG&E, SCE, CFE, and IID) and the SASG (APS, WALC).

On an annual basis, each sub-regional study group reviewed the paths in its sub-region to determine which paths should be studied and the system conditions under which they should be studied. Then, seasonally, the four sub-regional study group chairs submitted their recommendations of which paths to study to the OTCPC for review and approval. Following OTCPC's approval, the studies were performed in accordance with the OTC study process. This process began with establishment of an initial "base case" by WECC staff, with input from representatives of each sub-regional group. The "base case" is a computer model of projected or starting power system conditions for a specific point in time. For the 2010-2011 planning year, five base cases were used. Once the comments from the four sub-regional representatives were incorporated, the final cases were made available via WECC's web site for adjustment and modification by sub-regional members in order to forecast expected seasonal conditions on the system. The sub-regional members performed their own seasonal studies, and then met to discuss the results. A sub-regional seasonal planning case was produced on this basis, but no further studies were performed. Sub-regional seasonal cases were shared among the four sub-regions via liaisons from the other sub-regions. No comprehensive WECC-wide Path rating study was prepared on the basis of the four sub-regional studies.

In addition to, and apart from, the seasonal planning studies just described, TOPs also conduct their own seasonal studies focusing on their own internal networks. These internal studies follow a different process from the seasonal Path rating studies, though both begin with the WECC base case. Internal seasonal studies, however, are not aggregated or reviewed at the sub-regional level. Instead, TOPs generally replace the information from the WECC base case with more accurate and granular detail for their own areas only. Once updated, the TOPs perform contingency analyses for their own internal purposes. They then share with their neighbors the results of these operational studies, which typically contain only the default data from the WECC base case for everything outside of their own areas.

A number of issues relating to both types of seasonal planning by the affected entities were discovered. These issues impaired the accuracy and effectiveness of the seasonal studies by excluding, in various ways, pertinent issues and information that should have been taken into consideration.

Finding 5: Lack of Coordination in Seasonal Planning Process:

The seasonal planning process in the WECC region lacks effective coordination. Specifically, the four WECC sub-regions do not adequately integrate and coordinate studies across the sub-regions, and no single entity is responsible for ensuring a

thorough seasonal planning process. Instead of conducting a full contingency analysis based on all of the sub-regions' studies, the sub-regions rely on experience and engineering judgment in choosing which contingencies to discuss. As a result, individual TOPs may not identify contingencies in one sub-region that may affect TOPs in the same or another sub-region.

Recommendation 5:

WECC RE should ensure better integration and coordination of the various sub-regions' seasonal studies for the entire WECC system. To ensure a thorough seasonal planning process, at a minimum, WECC RE should require a full contingency analysis of the entire WECC system, using one integrated seasonal study, and should identify and eliminate gaps between sub-regional studies. Individual TOPs should also conduct a full contingency analysis to identify contingencies outside their own systems that can impact the reliability of the BPS within their system and should share their seasonal studies with TOPs shown to affect or be affected by their contingencies.

No comprehensive WECC-wide seasonal studies are performed. With respect to seasonal Path rating studies, a representative or leader from each sub-region adapts the WECC base case on the basis of input from sub-regional members, and then makes these revised cases available to the other sub-regional members for review, comment, and approval. The sub-regional leader then conducts the seasonal studies concentrating only on the Rated Paths in the sub-region. The results of the seasonal Path rating studies are shared and discussed first among the sub-region's members, and then with the other sub-regions, but neither WECC RE nor the OTCPC performs or mandates any further seasonal studies, and no new WECC-wide seasonal study is performed to reflect the input of all of the sub-regions. Instead, representatives of the sub-regional groups gather informally to discuss the results of their seasonal studies and rely on experience and engineering judgment to identify and resolve any issues.

The events of September 8, 2011, illustrate that this process is not adequate: the tripping of one line in a rated Path—H-NG, which is part of Path 49—ultimately led to the tripping of other lines in other Rated Paths, including Paths 44 and 45. Focusing exclusively on Path ratings—and solely on a sub-regional basis—ignores network facilities that can impact Rated Paths (and vice-versa) and does not account for the interrelationships of paths and other facilities across WECC's sub-regions.

With respect to the internal seasonal studies, there is even less coordination. TOPs generally perform internal seasonal studies using models that include detailed data for their own system, but default to WECC base case data, which may not be sufficiently detailed or updated, for everything else. TOPs perform contingency analysis for their own internal areas using this model. No study is done to identify the impact of external contingencies on the TOP's system, or the impact of the TOP's internal contingencies on the SOLs of other TOPs. TOPs provide the results of their internal seasonal studies to neighboring TOPs for informational purposes, after which those TOPs may or may not provide comments.

In all, this situation indicates that the TOPs' internal seasonal planning studies are too heavily reliant upon the assumptions underlying and reflected in a single WECC base case, and do not consider and study impacts of variations from that base case.

The September 8th event demonstrated one example where better integration of seasonal studies across two sub-regions is needed. When H-NG (part of Path 49) tripped, approximately 12% of the flow from that line, which is located in the SASG sub-region, was transferred across IID's 230/92kV transformers, via the IID 92kV local network to the southern IID 161 kV network, which are all in the OSS sub-region. This additional flow on IID's CV transformers ultimately resulted in cascading outages and impacted Paths 44 and 45. The affected entities were unaware of this potential inter-Path impact, because the SASG and OSS studies had not been jointly considered. Moreover, since the sub-regional studies concentrate only on Path ratings, this flow transfer was not apparent. If the seasonal studies of SASG and OSS had been better coordinated and more rigorously analyzed, the potential for the loss of H-NG to overload IID's 92 kV network could have been identified and mitigation plans developed.

Finding 6: External and Lower-Voltage Facilities Not Adequately Considered in Seasonal Planning Process:

Seasonal planning studies do not adequately consider all facilities that may affect BPS reliability, including external facilities and lower-voltage facilities.

Recommendation 6:

TOPs should expand the focus of their seasonal planning to include external facilities and internal and external sub-100 kV facilities that impact BPS reliability.

As noted above, TOPs performing sub-regional Path rating studies do not sufficiently account for the impact of facilities external to their sub-region, or facilities within their sub-region that are not part of a rated Path. Moreover, no WECC-wide Path rating study is performed to harmonize and analyze the impact of one sub-region on the rest of the sub-regions.

The problem with this approach is illustrated in the example cited above: The tripping of a part of one rated Path, H-NG, which is part of Path 49, led to the tripping of portions of other Rated Paths. The mechanism whereby these other trips were triggered was the transfer of flow across low-voltage (below 100 kV) facilities that were located in a different sub-region. Under the approach to Path rating studies in place at the time, it would have been impossible for WECC RE or TOPs to anticipate and study this possibility, because it occurred across sub-regions, indirectly, via lower-voltage facilities. Even if seasonal Path rating studies had been performed across sub-regions, these studies would not have anticipated this possibility, unless they also took into account lower-voltage facilities, which they presently do not.

The internal seasonal planning studies of the various TOPs are subject to similar omissions, although these studies encompass more than just the Rated Paths and contain more detail than the Path rating studies. The practices of individual TOPs differ, but none contains sufficient detail and accuracy with respect to facilities outside their own footprints, as well as lower-voltage facilities. IID, for example, has explained that it "does not identify or study components outside of the IID territory below 100 kV for impacts on the BPS reliability in its territory," nor does it "identify or study components inside of the IID territory below 100 kV for impacts on the BPS reliability outside of its territory."

Similarly, while CAISO studies in its seasonal planning process "all of the transmission components that it operates, some of which are below 100 kV," it has also acknowledged that it "does not have the necessary information to accurately study transmission components below 100 kV outside of its territory to determine if they have an impact on the BPS reliability in [CAISO's] service territory."

The events of September 8, 2011, demonstrate that sub-100 kV facilities in parallel with BPS systems can have a significant effect on BPS reliability. The loss of H-NG caused the overloading and tripping of both 230/92 kV transformers at CV, which in turn caused another sub-100 kV transformer to trip at Ramon, which led to the cascading outages discussed in detail above. This possibility was not studied as part of the seasonal studies by any of the TOPs, other than IID, because the CV transformers' secondary windings are below 100 kV. The seasonal studies conducted by affected TOPs, other than IID, did not study the impact of the CV transformers. If the CV transformer contingency overloads had been identified as limiting elements in the seasonal plans, the cascading outages might have been avoided or lessened by having pre-contingency mitigation in place, such as increasing generation on IID's 92 kV system.

Finding 7: Failure to Study Multiple Load Levels:

TOPs do not always run their individual seasonal planning studies based on the multiple WECC base cases (heavy and light load summer, heavy and light load winter, and heavy spring), but, instead, may focus on only one load level. As a result,

contingencies that occur during the shoulder seasons (or other load levels not studied) might be missed.

Recommendation 7:

TOPs should expand the cases on which they run their individual planning studies to include multiple base cases, as well as generation maintenance outages and dispatch scenarios during high load shoulder periods.

WECC created five base cases for the 2010-2011 season— heavy and light load summer, heavy and light load winter, and heavy spring—intended to capture the spectrum of possible loading configurations at different times of the year. Some of the affected TOPs deemed it unnecessary to run individual planning studies based on the multiple WECC base cases. Instead, these TOPs identified some subset of these base cases that they concluded were most relevant to their concerns and ran studies based on only that subset of base cases. Some TOPs employed only one base case—the heavy load summer base case—for planning the season during which the September 8, 2011 blackout occurred. By limiting the run of planning studies to a small subset of base cases, TOPs restrict their ability to anticipate and respond to contingencies arising in the context of load levels that vary significantly from those in the subset of base cases upon which their studies were predicated.

As noted above, September 8, 2011 was a very hot day in the region, and scheduled flows in the IID footprint were near record peaks. The high demand on September 8th was indeed similar to what would have been modeled in a heavy load summer seasonal study. The generation picture, however, was very different. By September 8, 2011 generation maintenance—which is not typically scheduled for summer peak days—had begun. The “heavy peak” summer study base cases that were actually used for September 8th therefore had built into them the incorrect assumption that there would be minimal maintenance—i.e., that most generation would be on line—and thus did not account for the normal resumption of facility maintenance in the shoulder season.

If IID’s seasonal studies had assumed even a modest decrease in the available generation, they might have enabled IID to anticipate and prevent the events that occurred on its system. IID was unaware of the TDM maintenance outages, but if it had conducted a shoulder season study, it might have been operating in a mode that more accurately reflected actual operating conditions on that day and could have potentially avoided the overloading of CV transformers to the tripping point. This lack of awareness illustrates the risks of not separately modeling the shoulder months such as September, when facility maintenance has begun but demand could remain or become very high. During these times, generation to serve load may come from other areas, changing flow patterns from those that typically occur on a normal summer peak day in which most generation is on line.

Finding 8: Not Sharing Overload Relay Trip Settings:

In the seasonal planning process, at least one TOP did not share with neighboring TOPs overload relay trip settings on transformers and transmission lines that impacted external BPS systems.

Recommendation 8:

TOPs should include in the information they share during the seasonal planning process the overload relay trip settings on transformers and transmission lines that impact the BPS, and separately identify those that have overload trip settings below 150% of their normal rating, or below 115% of the highest emergency rating, whichever of these two values is greater.

As discussed in greater detail below, the relay trip settings of IID's CV 230/92 kV transformers were set very low, just above the facilities' emergency rating. These settings effectively meant that IID's system operators had very little time to respond to the overload resulting from the loss of H-NG beyond emergency ratings and could not rely on post-contingency mitigation. If IID's neighbors had been aware of the relay trip settings on these transformers when preparing their seasonal studies, they would have been able to plan for the possibility of the CV transformers tripping at a lower trip point.

As a general matter, TOPs should be aware of the relay trip settings of facilities in neighboring areas that have the potential to impact portions of the BPS within their own areas, regardless of whether or not those facilities have been defined as, or deemed to be, BES facilities. This concern is particularly acute where the overload trip points of the facility in question are set below 150% of their normal rating, or below 115% of their emergency rating, because, as discussed below, such settings sharply limit the amount of time available for operators to implement post-contingency mitigation measures. These settings require that all entities that could be affected are aware and able to implement pre-contingency mitigation.

Near-and Long-Term Planning

Background

TPs and PCs conduct near- and long-term studies to ensure their systems are planned for reliable operation under normal operating conditions. In addition, the system facilities must remain stable in the event of single and multiple contingency scenarios. Near-term studies consider potential contingencies one to five years past the study date, and long-term studies consider potential contingencies six to ten years past the study date. The near- and long-term planning process in the WECC region involves a coordinated effort among individual TPs and PCs at the local level, *Sub-regional Planning Groups* (SPGs) at the regional level, and WECC RE at the Interconnection-wide level. It is a multi-step process, performed annually.

First, TPs and PCs submit data about their internal networks to their respective SPG for each horizon year studied (i.e., years one through ten). These data include forecasted load levels and facilities projected to be in or out of service. Also, these data assume peak load conditions and, thus, reflects that most internal generation is online. Second, SPGs add information to these data based on their broad knowledge of planning projects and reliability issues within their respective regions. For example, an SPG might add data for a particular horizon year based on its knowledge of a merchant generator's desire to connect to the grid. SPGs also consider future projects needed for reliability and the effect of environmental regulations on the future operation of generator units. Third, SPGs merge all of their members' cases to create a regional case. Fourth, WECC RE merges the various regional cases from all the SPGs to create the base case for each horizon year. WECC RE makes these cases available on its website for TPs, PCs, and SPGs to access. Finally, TPs and PCs add their own sub-transmission facilities to the base cases to run their near- and long-term studies. TPs and PCs typically choose a list of contingencies to study based on past experience and engineering judgment.

As discussed below, this multi-step process has several shortcomings, which left the affected entities unprepared for the September 8th event.

Finding 9: Gaps in Near- and Long-Term Planning Process:

Gaps exist in WECC RE's, TPs' and PCs' processes for conducting near- and long-term planning studies, resulting in a lack of consideration for: (1) critical system conditions; (2) the impact of elements operated at less than 100 kV on BPS reliability; and (3) the interaction of protection systems, including RASs. As a consequence, the affected entities did not identify during the planning process that the loss of a single 500 kV transmission line could potentially cause cascading outages. Planning studies conducted between 2006 and 2011 should have identified the critical conditions that existed on September 8th and proposed appropriate mitigation strategies.

Recommendation 9:

WECC RE should take actions to mitigate these and any other identified gaps in the procedures for conducting near- and long-term planning studies. The September 8th event and other major events should be used to identify shortcomings when developing valid cases over the planning horizon and to identify flaws in the existing planning structure. WECC RE should then propose changes to improve the performance of planning studies on a sub-regional- and Interconnection-wide basis and ensure a coordinated review of TPs' and PCs' studies. TOPs, TPs and PCs should develop study cases that cover critical system conditions over the planning horizon; consider the benefits and potential adverse effects of all protection systems, including RASs, Safety Nets (such as the SONGS separation scheme), and overload protection schemes; study the interaction of RASs and Safety Nets; and consider the impact of elements operated at less than 100 kV on BPS reliability.

The affected entities' near- and long-term planning studies for horizon year 2011 (i.e., the studies conducted in 2001 through 2010) did not identify that the loss of a single 500 kV line in APS's territory would cause cascading outages across the territories of SDG&E, CFE, IID, and WALC.

Several gaps in the near- and long-term planning process contributed to these omissions. First, TPs and PCs submit peak load data to WECC for incorporation into the base case and, thus, the data assume that most internal generation is online to meet peak conditions. As a result, the models for 2011 did not contain accurate, realistic representations of online generation. Running studies under the assumption that most generation is online provided an unrealistic portrayal of system transfers on the day of the event.

Indeed, system transfers following the loss of H-NG were higher than the transfers seen in the base case used for near- and long-term studies. Significant flows from H-NG transferred across IID's and WALC's systems and onto Path 44. Flow on Path 44 increased by approximately 84% following the loss of the line. These large system transfers went undetected in near- and long-term studies, and the affected entities were not alerted to the need to plan for these critical system conditions. To avoid this problem in the future, TPs and PCs should study more generation dispatch scenarios to provide a more realistic projection of system transfers following contingencies.

Second, TPs and PCs do not run a full list of external contingencies during the near- and long-term planning process. Instead, they rely on experience and engineering judgment, focusing on previously identified contingencies. This can be particularly problematic in today's operating environment in which the nature and limitations of the system are rapidly changing. For example, as part of its near- and long-term planning IID studied potential contingencies on four

WECC Rated Paths, but did not study the loss of H-NG. As a result, IID was not prepared for the effect on its system when that line tripped. Also, while IID's CV 230/92 kV transformers are included in the base case, some of the affected TPs and PCs did not study the potential loss of these facilities. By not considering a complete list of external contingencies that could impact their systems, TPs' and PCs' studies for horizon year 2011 were not sufficient to identify and plan for the impact of external contingencies on their internal systems or internal contingencies on neighboring systems.

Third, TPs and PCs do not study external sub-transmission facilities in the near- and long-term planning process. Individual TPs and PCs add their own sub-transmission facilities after the base case has been created by WECC RE, but do not add external sub-transmission equipment. If external sub-transmission systems were included in the base case, entities could identify the parallel flow on such lower-voltage systems that can result from transmission contingency outages. This consideration is particularly important for lower voltage systems that parallel external high voltage systems. For example, when APS's H-NG tripped, approximately 12% of its flow transferred to IID's 92 kV system. This increased flow and overloading on IID's system had a ripple effect, causing cascading outages throughout neighboring territories. Because the affected entities did not study external sub-transmission systems in their near- and long-term studies, they did not identify the potential for overloading on IID's 92 kV system or the impact on their systems from this overloading.

Fourth, TPs and PCs do not sufficiently study the interaction of protection systems in external networks in their near- and long-term planning studies. For example, some of the affected TPs and PCs did not study the interaction between the overload protection on IID's three 230/92 kV transformers, or between the protection on these transformers and the "S" Line RAS. Based on the pre-event conditions, the loss of one CV transformer would automatically result in the loss of the second, followed automatically by the loss of the Ramon transformer, which in turn, would result in either voltage collapse and load shedding, or overloading on the "S" Line. The "S" Line RAS is designed to mitigate overloads by tripping generation in Mexico that supplies power to IID. However, operation in this manner only served to further overload IID and WALC facilities and exacerbate system conditions on the day of the event. The affected entities should have studied the interaction of these schemes to prepare for the impacts on their systems.

Finding 10: Benchmarking WECC Dynamic Models:

There was a very good correlation between the simulations and the actual event until the SONGS separation scheme activated. After activation of the scheme, however, neither the tripping of the SONGS units nor the system collapse of SDG&E and CFE could be detected using WECC dynamic models because some of the elements of the event are not explicitly included in those models. Sample

simulations of the islanded region showed that by adding known details from the actual event, including UFLS programs and automatic capacitor switching, the simulation and event become more closely aligned following activation of the SONGS separation scheme.

Recommendation 10:

WECC dynamic models should be benchmarked by TPs against actual data from the September 8th event to improve their conformity to actual system performance. In particular, improvements to model performance from validation would be helpful in analysis of under and/or over frequency events in the Western Interconnection and the stability of islanding scenarios in the SDG&E and CFE areas.

The dynamic system response of the September 8th event from prior to the loss of H-NG through the separation of Path 44 and the unsuccessful islanding of SDG&E and CFE was simulated and there was a very good correlation between the simulation model and the actual event until the SONGS separation scheme activated. However, neither the tripping of the SONGS units nor the system collapse of SDG&E and CFE could be predicted using existing WECC dynamic models entities use to perform near- and long-term planning.

This inability to use the existing system models to reproduce the actual event is also evident in the post-event analysis that was prepared by SDG&E on the effectiveness of UFLS programs following the September 8th event. The SDG&E post-event analysis shows that the UFLS performance should have prevented the SDG&E system from frequency collapse. However, the SDG&E analysis does not explain why the simulation results are so different than the actual system responses—i.e., successful islanding operation versus system collapse.

The FERC/NERC committee was able to obtain a simulation more closely aligned with actual measured performance by performing several sensitivity data, and generation tripped in CFE's and SDG&E's territories. For example, one sensitivity study (referred to here as "Test 3") simulated approximately:

a. 3,080 MW of UFLS in SDG&E 1.3 seconds after Path 44 tripped (compared to 2,760 MW in "as-is" case)
b. 520 MW of UFLS in CFE after Path 44 tripped, but prior to SDG&E separation from CFE/APS (compared to 900 MW modeled in "as-is" case)
c. 589 MW of generation tripped in CFE after Path 44 tripped, but prior to SDG&E separation from CFE/APS (compared to zero in "as-is" case)
d. 1,000 MW of generation tripped in SDG&E immediately after SDG&E separated from CFE/APS (compared to zero in "as-is" case)

The simulation studies explain the ineffectiveness of the UFLS program, despite up to 75% of SDG&E load that was shed within 1.3 seconds of the SONGS separation scheme operating. The simulation analysis confirmed findings that the frequency collapse was caused by generation trips and UFLS misoperations within CFE shortly after Path 44's separation, followed by additional generation trips within SDG&E around the time it separated from CFE/APS.

II. Situational Awareness

Background

TOPs, BAs, and RCs have system operators who constantly monitor their networks to maintain situational awareness of system conditions, identify potential system disturbances, and institute mitigating measures, as necessary. The affected entities utilize a range of tools to perform these functions. All of the entities use SCADA systems as their main monitoring tool. SCADA systems typically consist of a central computer that receives information from various RTUs and intelligent electronic devices (IEDs), located throughout the system. SCADA systems provide control center operators with real-time measurements of system conditions and can send alarms to signal a problem.

Most of the affected entities also use several other tools to study and analyze the information received from their SCADA systems. Two of the most important tools are **State Estimator** and *RTCA*. State Estimator gathers the available measurements from the SCADA system and calculates estimated real-time values for the whole system. RTCA then takes the information from State Estimator and studies “what if” scenarios. For example, RTCA determines the potential effects of losing a specific facility, such as a generator, transmission line, or transformer, on the rest of the system. In addition to studying the effects of various contingencies, RTCA can prioritize contingencies. It can also provide mitigating actions and send alarms (visual and/or audible) to operators to alert them to potential contingencies.
While most of the affected entities have and use these tools, the inquiry identified several concerns with entities’ ability to adequately monitor, identify, and plan for the next most critical contingency in real time. Several areas for improvement are described in the findings below.

PMUs did not play a role in observing the September 8th event in real time, but may prove increasingly important in situational awareness. Of the affected entities, CAISO, SCE, and APS are equipped with PMUs. PMUs are widely distributed throughout WECC as the result of a WECC-wide initiative known as the Western Interconnection Synchrophasor Program (WISP). Their high sampling speed (up to 30 samples per second) and excellent GPS-based time synchronization offer new granularity in information about voltage phase angles and other grid conditions. PMUs are expected to be used to identify and monitor for grid stress, grid robustness, dangerous oscillations, frequency instability, voltage instability, and reliability margins. While not yet sufficiently integrated to have been used by the affected entities in their control rooms on September 8th, as discussed earlier, PMU data proved valuable in constructing the sequence of events and other post-event analysis.

Finding 11: Lack of Real-Time External Visibility:

Affected TOPs have limited real-time visibility outside their systems, typically monitoring only one external bus. As a result, they lack adequate situational awareness of external contingencies that could impact their systems. They also may not fully understand how internal contingencies could affect SOLs in their neighbors' systems.

Recommendation 11:

TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. 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.

Although all of the affected TOPs use SCADA to monitor their own systems, some TOPs' situational awareness is hindered by their limited visibility into neighboring systems. Some of the affected TOPs' real-time external visibility is limited to one or two buses outside their systems. The September 8, 2011, event demonstrated that more expansive visibility into neighboring systems is necessary for these TOPs to maintain situational awareness of external conditions and contingencies that could impact their systems and internal conditions and contingencies that could impact their neighbors' systems. During the 11-minute time span of the September 8th event, entities observed changes in flows into their systems, but were unable to understand the cause or significance of these changes and lacked sufficient time to take corrective actions. If affected entities had seen and run studies based on real-time external conditions prior to the event, they could have been better prepared to re-dispatch generation or take other control actions and deal with the impacts when the event started.

IID, for example, is adjacent to APS, and the changes in flows on APS's system, especially on its 500 kV lines, can affect the flows on IID's system and vice versa. Yet, IID's visibility into APS's system is limited to information about the tie line between them. In fact, IID's visibility into all of its neighbors is limited to one or two buses outside its system. As a result, IID did not learn in real-time that H-NG tripped. IID also did not understand prior to the event how changes in flows or the loss of H-NG would affect its system. Immediately after H-NG tripped, IID observed loading on its CV transformers escalate rapidly, but it had not been prepared for this escalation.

If IID had greater visibility into APS's system and IID had an equivalent on its RTCA that modeled the external network using APS's real-time data instead of pseudo-generators modeled at the end of each tie line, IID's RTCA could have more accurately studied the results of a post-contingency loss of H-NG on its system before it occurred. After seeing the more accurate RTCA results, IID could have initiated appropriate control actions before H-NG tripped. Also, having real-time status of the H-NG would have better prepared IID to deal with the effects of its loss in real time.

In addition to IID not having adequate situational awareness of APS's system, the affected TOPs and BAs external to IID were not aware in real time of the effect of the post-contingency loss of IID's three 230/92 kV transformers on their systems. Losses of the CV and Ramon transformers can cause SOL violations on neighboring systems. Indeed, on September 8th, these transformer outages had a significant ripple effect and led to the cascading nature of the event. Yet, entities outside IID's footprint were not prepared for these outages and, except for WECC RC, were unaware of the outages in real time because of a lack of adequate visibility into IID's system. For example, at the time of the event, CAISO's visibility into IID's system stopped at the tie line into IID's El Centro station.

The September 8th event exposed the negative consequences of TOPs having limited external visibility into neighboring systems. Providing TOPs with the ability to observe and model external system conditions and events on a continuous real-time basis will allow them to study and plan for the impact of external conditions and contingencies before it is too late to react, as was the case on September 8th.

Finding 12: Inadequate Real-Time Tools:

Affected TOPs' real-time tools are not adequate or, in one case, operational to provide the situational awareness necessary to identify contingencies and reliably operate their systems.

Recommendation 12:

TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.

Although many of the affected TOPs have and use real-time tools such as State Estimator and RTCA, some of the tools are not adequate or operational to provide the situational awareness necessary to effectively monitor and operate their systems. Also, some TOPs run or view these tools infrequently, while others run RTCA, for example, every five minutes.

The alarming function on IID's RTCA provides an example of a real-time tool that does not adequately maximize situational awareness capabilities. IID's RTCA does not provide operators with any audible alarms or pop-up visual alerts when an overload is predicted to occur. Instead, IID's RTCA uses color codes on a display that the operator must call up manually to learn of significant potential contingencies. For example, IID's RTCA might show that on the next contingency, a specific element will become overloaded. However, as currently designed, the operator must go to the specific page related to this element to view this result. The result will be color coded on this page, but this code does not function as an alarm.

This design feature of IID's RTCA had negative consequences on the day of the event. Forty-four minutes prior to the loss of H-NG, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in overloading of the second CV transformer to its tripping point. If IID had taken action at this pre-contingency stage, it could have avoided the loss of both transformers. The IID operator, however, did not view the appropriate RTCA display and, therefore, was not alerted to the need to take action. If the operator had reviewed the RTCA results and taken necessary corrective actions, he could have relieved loading on the transformers at this pre-event stage, and thus mitigated the severe effects on the CV transformers that resulted when H-NG tripped.

One affected entity, APS, has State Estimator and RTCA capability, but neither tool is operational. As a result, APS has limited capability to monitor and operate its system to withstand potential real-time contingencies. Instead of using RTCA, APS relies on a set of previously studied contingencies and pre-determined plans to mitigate them. These studies are included in a manual that is created annually and usually updated several times a year. By relying on pre-determined studies, APS cannot account and prepare for all potential contingency scenarios in real time. RTCA would provide APS with a more realistic analysis of its next potential contingency because the RTCA analysis is based on real-time conditions, as measured by State Estimator. Without RTCA, APS operators are not fully prepared to identify and plan for the next most critical contingency on its system.

RTCA would have allowed APS operators to study the impact of the loss of its H-NG. Although APS could have studied this contingency in its manual and seasonal studies, it could not have studied it based on real-time operating conditions that only State Estimator can provide. For example, APS's manual and seasonal studies did not study the loss of H-NG together with the multiple generator outages that existed on the day of the event. As a result, APS was unprepared for the actual consequences of losing H-NG on September 8, 2011, including overloads on IID's 92 kV system and potential difficulty reclosing H-NG due to large phase angle differences.

Finding 13: Reliance on Post-Contingency Mitigation Plans:

One affected TOP operated in an unsecured N-1 state on September 8, 2011, when it relied on post-contingency mitigation plans for its internal contingencies and subsequent overload and tripping, while assuming there would be sufficient time to mitigate the contingencies. Post-contingency mitigation plans are not viable under all circumstances, such as when equipment trips on overload relay protection that prevents operators from taking timely control actions. If this TOP had used pre-contingency measures on September 8th, such as dispatching additional generation, to mitigate first contingency emergency overloads for its internal contingencies, the cascading outages that were triggered by the loss of H-NG might have been avoided with the prevailing system conditions on September 8, 2011.

Recommendation 13:

TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency. As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures.

Before September 8, 2011, IID consistently relied on post-contingency mitigation plans, rather than proactively responding on a pre-contingency basis, for RTCA results showing that the N-1 loss of one CV transformer would result in overloading on the second CV transformer. Post-contingency plans can work to prevent a second contingency as long as operators have sufficient time to take mitigating actions. Post-contingency mitigation is not an appropriate choice for the CV transformers, which are set to trip by overload protection relays without allowing operators enough time to take mitigating actions. Specifically, the transformers' overload protection scheme is set with a thin margin between the emergency rating and the relay trip point. The normal rating of the transformers is 150 MVA, the emergency rating is 165 MVA, and the relay trip point is set at 190.5 MVA, or 127% of the normal rating. Thus, when the transformers reach their emergency rating, operators may have the mistaken belief that they have sufficient time to take mitigating actions, when, in fact, the operators will have very little time before the transformers will trip offline, because they will soon reach the relay trip setting. As shown below, pre-contingency mitigation measures are necessary when operators are faced with settings that leave such little margin between the emergency rating and overload trip point.

On multiple days during the summer of 2011, IID's RTCA results showed that an N-1 contingency tripping of one of the CV transformers would result in overloading on the second transformer. IID continued to operate in this state on multiple days without taking any pre-contingency mitigating actions. For example, IID did not dispatch additional generation on a pre-contingency basis to control the loading on one CV transformer to prevent overloading on the second CV transformer. There were potentially severe consequences of not taking pre-contingency actions. Specifically, IID's next-day study for September 8th detailed that the loss of both CV transformers would overload: (1) IID's Ramon transformer to its trip point; and (2) the "S" Line, which, in turn, would cause the "S" Line RAS to trip generation in Mexico that supplies power to the Imperial Valley substation. In short, on multiple days in summer 2011, IID's RTCA results showed that the loss of one CV transformer would overload the second transformer, and IID's next-day study revealed the cascading outages that would stem from the loss of both transformers. Yet, IID did not institute pre-contingency mitigating measures, such as dispatching additional generation.

Instead, IID relied on post-contingency plans. On most days in summer 2011, the level of overloading on the CV transformers gave IID just enough time to successfully use a post-contingency mitigation plan to start generation after the loss of the first transformer to avoid the loss of the second transformer. However, on at least two days, a post-contingency plan would not allow the operator enough time to implement necessary procedures to mitigate the problem. On those two days, the loading on both CV transformers was high enough that only pre-contingency mitigation measures could have prevented the loss of the second transformer upon the loss of the first. On the first of those two days, IID was simply fortunate that the N-1 contingency loss of the first transformer never occurred. The second of the two days was September 8, 2011.

Forty-four minutes prior to the loss of H-NG, IID's RTCA results showed that the N-1 contingency loss of the first CV transformer would result in overloading of the second transformer to approximately 139% of its normal rating—leading to the loss of the transformer by relay action. If IID had taken action at this pre-contingency stage, IID might have been able to avoid the loss of both transformers. After H-NG tripped, the relays took less than 40 seconds to trip both CV transformers. Operators had no time to mitigate the overloads before the transformers were removed from service.

Finding 14: WECC RC Staffing Concerns:

WECC RC staffs a total of four operators at any one time to meet the functional requirements of an RC, including continuous monitoring, conducting studies, and giving directives. The September 8th event raises concerns that WECC RC's staffing is not adequate to respond to emergency conditions.

Recommendation 14:

WECC RC should evaluate the effectiveness of its staffing level, training and tools. Based on the results of this evaluation, it should determine what actions are necessary to perform its functions appropriately as the RC and address any identified deficiencies.

WECC RC performs its reliability coordination functions through two offices. Although each office is capable of monitoring the entire Interconnection, during normal operations the offices have primary responsibility for monitoring different parts of the Western Interconnection. WECC RC's Vancouver, Washington, office is primarily responsible for monitoring the Pacific

Northwest (excluding PacifiCorp East), California, and CFE's territory in Mexico. WECC RC's Loveland, Colorado, office is primarily responsible for monitoring the Desert Southwest area, Rocky Mountain area, PacifiCorp's East area, Sierra Pacific Power Company's area, IID's area, and the Los Angeles intermountain area. Each office staffs two on-shift operators at all times. Each center dedicates an operator to the real-time desk (real-time operator) and the other operator to the study desk (study desk operator).

The real-time operator's primary responsibilities include monitoring limits and operating parameters, identifying exceedances, evaluating mitigation plans, and directing corrective actions. The study desk operator's primary responsibilities include monitoring expected post-contingency conditions to identify potential exceedances, evaluating actions being taken, and directing corrective action as necessary. The study desk operator also reviews WECC RC's next-day study for accuracy, conducts real-time studies to evaluate system conditions, and monitors EMS applications, such as RTCA, to identify any performance issues and request corrective actions, as necessary. The real-time operator and study desk operator also have some joint responsibilities, including reporting events that impact the BPS, identifying events or system conditions that require notification to adjacent RCs, and monitoring and testing primary and backup internal communication systems. Through these responsibilities, WECC RC is responsible for the reliable operation of the BPS in the WECC footprint, and it has the ultimate authority to prevent or mitigate emergency operating situations in both next-day and real-time timeframes.

In addition, WECC RC is responsible for providing information to the entities in its footprint, including the 53 TOPs and 37 BAs. Some of this information is provided over the telephone. During the event, in addition to performing the many RC functions they are responsible for performing, the RC operators had to answer phone calls providing or seeking information on the disturbance.

Given WECC RC's responsibility and authority, four total operators—two in each regional office—might not be sufficient to effectively perform its function, particularly during emergency conditions. Several examples from the September 8th event highlight this concern.

First, after the loss of H-NG, many alarms began sounding in WECC RC's control rooms, as voltage dropped and facilities overloaded. With so many alarms sounding in an emergency situation, the real-time operator had a difficult time prioritizing which alarms to monitor. WECC RC has eight unique categories, or "buckets," of alarms within its EMS applications, grouped according to importance. Buckets 1 and 2 contain the highest priority alarms. Bucket 1 includes all 500 and 345 kV circuit breaker status changes, frequency and Path violations, status of generators greater than 50 MW and associated circuit breakers, and critical bus voltages. Bucket 2 includes all 220/230 kV circuit breaker status changes and automatic voltage regulator status. Buckets 3 through 8 include lesser priority items, such as RAS status changes, non-critical bus voltages, and circuit breaker status changes below 220 kV. Operators receive audible alarms for buckets 1 and 2 and typically leave bucket 1's display on the screen constantly and use one other screen to display all other buckets. It is a constant process to continually monitor the alarms, even during normal operating conditions, and it might not be possible for one real-time operator to keep track of and prioritize multiple alarms sounding at once. Also, both operators had numerous phone calls to field from entities throughout the affected areas, reporting and requesting information. Overburdening the real-time operator in this way could undermine his or her ability to perform the critical functions of monitoring system conditions and directing necessary corrective actions. Accordingly, WECC RC should consider whether additional operators are necessary to adequately perform these functions.

A second indication that the current RC staffing levels might not be sufficient came during the September 8th event when the study desk operator had to abandon his duties in order to provide support to the real-time operator by fielding phone calls and monitoring conditions. On this day, the RC operators were able to call for an engineer to conduct some studies. Because the September 8th event occurred during the afternoon, an engineer was available. Finding an engineer to substitute for the study desk operator may not always be so easy. Late at night and early in the morning, no engineers are on duty. That the study desk operator needed to leave his responsibilities to support the real-time operator may indicate that one real-time operator and one study desk operator per office might not be sufficient to fulfill WECC's reliability coordination functions.

Alternatively, additional training and enhanced tools may enable an entity to accomplish more with the same number of personnel. While the inquiry observed a sampling of WECC RC's tools to be adequate during its site visit, WECC RC is in the best position to identify the combination of additional staff, enhanced tools, or training that best addresses the concerns identified by this report.

Finding 15: Failure to Notify WECC RC and Neighboring TOPs Upon Losing RTCA:

On September 8, 2011, at least one affected TOP lost the ability to conduct RTCA more than 30 minutes prior to and throughout the course of the event due to the failure of its State Estimator to converge. The entity did not notify WECC RC or any of its neighboring TOPs, preventing this entity from regaining situational awareness.

Recommendation 15:

TOPs should ensure procedures and training are in place to notify WECC RC and neighboring TOPs and BAs promptly after losing RTCA capabilities.

When entities temporarily lose their RTCA capability due to technical issues, they become blind to the next most severe contingency on their system, and they do not know what pre-contingency measures might be necessary. Thus, when they lose RTCA, they must take immediate action to try to regain their situational awareness. For example, after losing RTCA an entity should contact WECC RC, so the RC can monitor the entity's system and inform it of any significant issues. In such instances, the RC should also notify neighboring entities of any major contingencies that could impact their systems.

Between 13:59 and the start of the event on September 8, 2011, WALC lost its RTCA when its State Estimator stopped solving. As a result, WALC lost its ability to identify and study post-contingency violations and to take pre-contingency mitigating measures, as necessary. When it lost its RTCA, WALC should have contacted WECC RC and asked it to monitor WALC's area. WECC RC could have then notified WALC regarding any significant problems and could have also contacted WALC's neighbors if it learned of any SOLs in WALC that were impacting the neighbors' systems. Prior to the event on September 8, 2011, WALC experienced several post-contingency SOL violations, but, without its RTCA capability, remained unaware of them. WECC RC's RTCA results showed these violations. WALC, however, did not notify WECC RC when it lost RTCA and, thus, WECC RC was unaware that it should notify WALC of the violations. An entity should never be operating in an unknown state, as WALC was when it lacked functional RTCA and State Estimator, and did not ask any other entity to assist it with situational awareness.

Finding 16: Discrepancies Between RTCA and Planning Models:

WECC's model used by TOPs to conduct RTCA studies is not consistent with WECC's planning model and produces conflicting solutions.

Recommendation 16:

WECC should ensure consistencies in model parameters between its planning model and its RTCA model and should review all model parameters on a consistent basis to make sure discrepancies do not occur.

The usefulness of RTCA study results and other real-time studies depend on the models used in the studies. Inaccurate models jeopardize the accuracy of studies, as well as entities' ability to respond appropriately to potential contingencies identified by the studies. The simulation of the September 8th event discovered that a discrepancy exists between WECC RC's model used to conduct RTCA studies and the model used for WECC's planning studies.

Specifically, the impedance of IID's CV transformers differed by a factor of two between the WECC models. WECC's planning model has an impedance of 0.1 per unit, while WECC RC's RTCA model has an impedance of 0.05 per unit. This difference resulted in an error of approximately 16% in the RTCA model compared to the planning model with respect to loading on the CV transformers.

Although a comprehensive comparison of all parameters in WECC's various models was not performed, this discrepancy between the RTCA and planning models on such important facilities calls into question the validity of other parameters in WECC's models.

III. System Analysis

The system analysis includes a consideration of BES equipment, IROLS, impact of system protective equipment, system protection studies, load response, and angular separation.

Consideration of BES Equipment

Background

The BES is generally defined as all facilities operating at voltages above 100 kV, although certain sub-100 kV facilities with a significant impact on the BPS may be considered a part of the BES. Each RE currently determines its specific procedure for determining what is or is not BES. If a facility is not considered BES, relevant TOPs, BAs, and RCs may not study and model the impact of that facility.

Finding 17: Impact of Sub-100 kV Facilities on BPS Reliability:

WECC RC and affected TOPs and BAs do not consistently recognize the adverse impact sub-100 kV facilities can have on BPS reliability. As a result, sub-100 kV facilities might not be designated as part of the BES, which can leave entities unable to address the reliability impact they can have in the planning and operations time horizons. If, prior to September 8, 2011, certain sub-100 kV facilities had been designated as part of the BES and, as a result, were incorporated into the TOPs' and RC's planning and operations studies, or otherwise had been incorporated into these studies, cascading outages may have been avoided on the day of the event.

Recommendation 17:

WECC, as the RE, should lead other entities, including TOPs and BAs, to ensure that all facilities that can adversely impact BPS reliability are either designated as part of the BES or otherwise incorporated into planning and operations studies and actively monitored and alarmed in RTCA systems.

WECC RC, as well as TOPs and BAs impacted by the event, did not consider IID's 92 kV network and facilities (including the CV and Ramon transformers) as BES elements. IID did not reconsider whether the CV and Ramon transformers should be studied like BES facilities even after a draft study sponsored by CFE (and shared with IID) suggested the existence of a through-flow issue between the 500 kV substations at Devers and Imperial Valley, adversely impacting IID's 92 kV network (including the CV and Ramon transformers) during contingencies on BPS systems, including H-NG. Because the Reliability Standards apply to BES facilities, if the CV transformers had been considered BES facilities, IID would have been required to study the impact they could have on BPS reliability. Also, WECC RC and the affected TOPs would likely have included the facilities in their studies and been aware of the impact the loss of H-NG would have on IID's 92 kV system, as well as the impact various trips within IID's 92 kV system would have on the rest of the BPS. The inquiry determined that, during the event, approximately 12% (168 MW) of the original flow on H-NG was transferred through IID's 92 kV system, making the 92 kV system part of a bulk power path as well as a significant looped transmission facility. The cascading outages that resulted from the loss of H-NG demonstrated the significant potential for IID's 92 kV system, including the CV transformers, to impact BPS reliability.

IROL Derivations

Background

In order to ensure the reliable operation of the BPS, entities are required to identify and plan for IROLs, which are SOLs that, if violated, can cause instability, uncontrolled separation, and cascading outages. Once an IROL is identified, system operators are then required to create plans to mitigate the impact of exceeding such a limit to maintain system reliability.

An Interconnection Reliability Operation Limit, or **IROL**, is a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.

Finding 18: Failure to Establish Valid SOLs and Identify IROLs:

The cascading nature of the event that led to uncontrolled separation of San Diego, IID, Yuma, and CFE indicates that an IROL was violated on September 8, 2011, even though WECC RC did not recognize any IROLs in existence on that day. In addition, the established SOL of 2,200 MW on Path 44 and 1,800 MW on H-NG are invalid for the present infrastructure, as demonstrated by the event.

Recommendation 18.1:

WECC RC should recognize that IROLs do exist on its system and, thus, should study IROLs in the day-ahead timeframe and monitor potential IROL exceedances in real-time.

Recommendation 18.2:

WECC RC should work with TOPs to consider whether any SOLs in the Western Interconnection constitute IROLs. As part of this effort, WECC RC should: (1) work with affected TOPs to consider whether Path 44 and H-NG should be recognized as IROLs;

> *and (2) validate existing SOLs, and ensure that they take into account all transmission and generation facilities and protection systems that impact BPS reliability.*

The NERC Glossary defines an IROL as an SOL that, if violated, could expose a widespread area of the BPS to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the BPS. Each IROL is associated with a *maximum time limit* (Tv) that the IROL can be exceeded before the risk to the Interconnection or another RC area becomes greater than acceptable. The time limit can vary, but any IROL's Tv must be less than or equal to 30 minutes.

For this event, the loss of H-NG should have been associated with an IROL with a Tv for this N-1 contingency of essentially zero minutes, because the cascading from the loss of H-NG began within seconds. However, neither WECC RC nor any of the affected entities have previously identified this IROL. The WECC region historically has maintained an operating philosophy of not recognizing IROLs. Instead, entities in the WECC region believe that as long as they operate within the conditions they have studied, they will not face the risk of IROLs and will not need to calculate IROLs. The September 8th event undermines this philosophy.

Prior to the event, the WECC system was supplying loads in the various balancing authority areas in the range of 85-95% of their recorded peak loads. The power flows on all the paths in the WECC region were below their maximum ratings and voltages were within acceptable levels. In particular, the two major transmission corridors into the blackout area, namely Path 44 and H-NG, were loaded respectively to 1,302 MW and 1,372 MW. Compared to their maximum SOL ratings of 2,200 MW and 1,800 MW, these loadings represent 59% and 78% of their maximum ratings—well within current limits. Path 44 and H-NG ratings of 2,200 MW and 1,800 MW may be invalid for the present infrastructure because cascading outages due to a single contingency occurred at loadings well below the SOL ratings.

During the 11-minute disturbance, the single contingency of the sudden loss of H-NG resulted in a series of cascading outages, with multiple elements exceeding their applicable ratings and leading to a widespread blackout of the area.

Accordingly, WECC RC should lead all relevant TOPs in the blackout area to study and report on the appropriateness of identifying Path 44 and H-NG as IROL paths. WECC RC should similarly assess transfer paths outside this blackout area to ensure that there are no other similar reliability issues in the Western Interconnection. Existing operating processes and procedures should be reviewed to ensure corrective control capabilities are provided to system operators to enable them to return the system to a secure N-1 state as soon as possible, but no longer than 30 minutes following a single contingency.

WECC RC has a proposed new SOL Methodology document (current effective date of June 4, 2012), which acknowledges the need to establish IROLs, and the RC's responsibility to monitor IROLs. It recognizes that "Stability SOLs may qualify as IROLs depending on the potential consequences of exceeding the limit and the impact on BES reliability. WECC RC makes this determination by collaborating with TOPs to understand the nature of the stability SOL, understanding the conditions that result in the establishment of the stability SOL, and determining the BES impacts of exceeding the stability SOL." WECC RC also has a proposed multi-step process for determining whether thermal or voltage SOLs are IROLs. In general, WECC RC will look at whether potential IROLs cause "Widespread Adverse System Impacts," or "potential cascading." "Widespread Adverse System Impacts" is defined as "loading of three or more additional BES Facilities beyond 125% of their applicable emergency thermal Facility Rating, or three or more additional BES Facilities with bus voltages experiencing voltages less than 90%." "Potential cascading" is defined as "when studies indicate that a contingency results in severe loading on a Facility, triggering a chain reaction of Facility disconnection by relay action, equipment failure, or forced immediate manual disconnection of the Facility (for example, public safety concerns, or no time for the operator to implement mitigation actions)."

Impact of Protection Systems on Event

When an abnormal system condition is detected on the BPS, relay protection systems operate to isolate the problem while causing minimum disturbance to the power system. This requires the relay to be selective in determining which elements to interrupt. The only method of obtaining this selectivity is to perform coordination studies. Two TOs did not properly coordinate a protection system and a third TO implemented a protection scheme without performing any coordination studies at all. This lack of coordination of protection systems resulted in circuits unnecessarily being interrupted, which had an undesirable effect on BPS reliability during the September 8th event.

Finding 19: Lack of Coordination of the "S" Line RAS:

Several TOs and TOPs did not properly coordinate a RAS by: (1) not performing coordination studies with the overload protection schemes on the facilities that the "S" Line RAS is designed to protect; and (2) not assessing the impact of setting relays to trip generation sources and a 230 kV transmission tie line prior to the operation of a single 161/92 kV transformer's overload protection. As a result, BES facilities were isolated in excess of those needed to maintain reliability, with adverse impact on BPS reliability.

Recommendation 19:

The TOs and TOPs responsible for design and coordination of the "S" Line RAS should revisit its design basis and protection settings to ensure coordination with other protection systems in order to prevent adverse impact to the BPS, premature operation, and excessive isolation of facilities. TOs and TOPs should share any changes to the "S" Line RAS with TPs and PCs so that they can accurately reflect the "S" Line RAS when planning.

Operation of the "S" Line RAS isolates facilities beyond what is necessary to ensure reliability. The "S" Line RAS is a directional overload scheme, located at the Imperial Valley substation, which is jointly owned by SDG&E and IID. The "S" Line RAS was originally implemented to protect the sole 230/161 kV transformer at El Centro from overloads due to increased flow on the "S" Line. At the time, this was the only transfer point from the 230 kV line to the 161 kV system, and subsequently the 92 kV system, in IID's southern area. After implementing this RAS, IID has since installed a 230/92 kV transformer at El Centro, providing another path from the 230 kV system to the lower voltage networks.

IID's current intention for the "S" Line RAS is to reduce loading on the "S" Line by tripping generation and, if insufficient to reduce flow, tripping the "S" Line at Imperial Valley Substation before transformer overload protection operates to trip the 161/92 kV transformer at El Centro. Tripping the "S" Line before allowing the El Centro 161/92 kV transformer's overload protection to take action effectively results in the removal of the 230 kV source at the El Centro substation, which normally feeds a 230/92 kV transformer and a 230/161 kV transformer. Thus, the design of the "S" Line RAS intentionally isolates networked BES facilities to mitigate an overload on a non-BES facility (El Centro 161/92 kV transformer) to support reliability of the local system. While this action alone does not constitute mis-coordination, proper coordination of a RAS should take into account, through system studies, the potential impact on BPS reliability, including potential interaction with other RASs and protection systems.

During the September 8th event, the "S" Line RAS operated as designed, in that it tripped when it reached the settings that IID had prescribed. However, if one considers the purpose of the "S" Line RAS, which was to protect the El Centro transformer from overloads, the "S" Line RAS operated long before it was needed. At the time that the "S" Line RAS operated, the El Centro 161/92 transformer was only loaded to 38% of its normal rating, and its overload trip point is 178% of its normal rating. Thus, the El Centro 161/92 transformer could have carried at least four times as much load before the transformer's overload protection system would have operated. Even though the El Centro transformer that the "S" Line RAS was designed to protect was nowhere near overloading, the "S" Line RAS tripped important generation and a 230 kV line. This calls into question the coordination of the "S" Line RAS with the transformer overload protection systems at El Centro.

IID provided SDG&E with the "S" Line RAS settings to implement. IID did not perform any studies to coordinate the "S" Line RAS with IID's protection systems. SDG&E did some studies to verify that the RAS coordinated with SDG&E's protection systems. There is no indication that the "S" Line RAS was coordinated with IID's transformer overload protection at the El Centro station at which the "S" Line terminates. At a minimum, IID, SDG&E and CAISO (as the TOP for SDG&E) should work together to ensure the proper coordination of the "S" Line RAS.

To make matters worse, during the September 8th event, San Diego was relying on generation at Imperial Valley from the south when the "S" Line RAS tripped that generation. Loss of the Imperial Valley generation caused San Diego to pull even more power from the north, increasing the loading on Path 44 and causing the SONGS separation scheme to further exceed its trip point. If not tripped by the "S" Line RAS, generation at Imperial Valley could have helped SDG&E survive after the operation of the SONGS separation scheme. The inquiry's simulation showed that, had the "S" Line RAS tripped only the "S" Line without tripping the generation, the SONGS separation scheme would not have operated, and only IID would have lost power.

Finding 20: Lack of Coordination of the SONGS Separation Scheme:

SCE did not coordinate the SONGS separation scheme with other protection systems, including protection and turbine control systems on the two SONGS generators. As a result, SCE did not realize that Units 2 and 3 at SONGS would trip after operation of the separation scheme.

Recommendation 20:

SCE should ensure that the SONGS separation scheme is coordinated with other protection schemes, such as the generation protection and turbine control systems on the units at SONGS and UFLS schemes.

SCE, the TO and TOP of the SONGS separation scheme, did not perform any protection system coordination studies for the separation scheme it implemented at SONGS. The scheme is intended to isolate five 230 kV lines simultaneously if its pre-set value is exceeded for a sustained period. If SCE had coordinated the separation scheme with other protection and generation control systems at SONGS, it may have recognized the potential for the operation of the SONGS separation scheme to cause the SONGS generators to trip. Coordination in this context requires system studies to assess the impact of operation of the RAS on the power system, including potential interaction with other RASs and protection systems, such as UFLS schemes.

In addition to the consequences at SONGS itself, the lack of coordination of the systems means that, when the scheme operates, the system enters an unknown state. During the event, the operation of the protection scheme significantly contributed to the blackout of SDG&E, CFE, and Yuma—an effect neither coordinated nor adequately studied prior to the event. The inquiry's simulation indicates that SDG&E, CFE and, Yuma would not have been blacked out if the SONGS separation scheme had not operated, with limited impact to the rest of the Western Interconnection.

Finding 21: Effect of SONGS Separation Scheme on SONGS Units:

The SONGS units tripped due to their turbine control systems detecting unacceptable acceleration following operation of the SONGS separation scheme.

Recommendation 21:

GOs and GOPs should evaluate the sensitivity of the acceleration control functions in turbine control systems to verify that transient perturbations or fault conditions in the transmission system resulting in unit acceleration will not result in unit trip without allowing time for protective devices to clear the fault on the transmission system.

When the SONGS separation scheme operated, turbines at SONGS began to accelerate in excess of their control system setting causing both units to trip offline. The tripping of the SONGS units in this manner raises questions about the sensitivity of the turbine control system's settings. The units are expected to withstand severe faults on the transmission system and allow the transmission protection systems to operate without the generators tripping offline. The coordination required for this protection is not a traditional relay-to-relay coordination; rather, the setting for the acceleration function should be coordinated with capabilities of the turbine and with the system response anticipated following operation of transmission protection systems for faults under various system conditions. The setting should also be coordinated with the system response following operation of the SONGS separation scheme. Had the turbine control system acceleration function been coordinated in this manner, the trip of the units may have been avoided.

Protection System Studies

Finding 22: Lack of Review and Studying Impact of SPSs:

Although WECC equates SPSs with RASs, prior to October 1, 2011, WECC's definition of RAS excluded many protection systems that would be included within NERC's definition of SPS. As a result, WECC did not review and assess all NERC-defined SPSs in its region, and WECC's TOPs did not perform the required review and assessment of all NERC-defined SPSs in their areas.

Recommendation 22:

WECC RE, along with TOs, GOs, and Distribution Providers (DPs), should periodically review the purpose and impact of RASs, including Safety Nets and Local Area Protection Schemes, to ensure they are properly classified, are still necessary, serve their intended purposes, are coordinated properly with other protection systems, and do not have unintended consequences on reliability. WECC RE and the appropriate TOPs should promptly conduct these reviews for the SONGS separation scheme and the "S" Line RAS.

The NERC definition of an SPS concludes with "Also called Remedial Action Scheme." This implies that all SPSs are RASs and vice versa, but prior to October 1, 2011, the WECC region did not equate SPSs with RASs. WECC created four classifications of protection systems that fall under the NERC definition of SPS, and, instead of including all of these classifications in the RAS definition, WECC only identified a subset of those protection systems as RASs. Safety Nets, Wide Area Protection Systems (WAPS), and Local Area Protection Systems (LAPS) were excluded from the WECC definition of a RAS even though they are SPSs as defined by NERC.

For example, SCE did not study the impact of the SONGS separation scheme on BPS reliability because it believed, by classifying this scheme as a Safety Net, that it was not required to be studied. SCE also did not submit the separation scheme to WECC for review by the Remedial Action Scheme Reliability Subcommittee (RASRS). The inquiry determined that the SONGS separation scheme is indeed an SPS/RAS as defined by NERC, because it altered the BPS configuration by separating Path 44 and redistributing generation in the absence of any faulted equipment. WECC, SDG&E, and SCE did not study the impact that the SONGS separation scheme could have on BPS reliability and, thus, were unaware of its severe impact on the BPS when the scheme operated: blacking out SDG&E and CFE and leading to the loss of the SONGS generators.

Another protection system that did not get the necessary scrutiny due to WECC's narrow definition of RAS was the "S" Line RAS. The "S" Line is a 230 kV transmission line that serves as a major tie between SDG&E & IID. It runs from IID's and SDG&E's jointly owned Imperial Valley station on one end to IID's El Centro station on the other. The "S" Line RAS, as IID and SDG&E called it, was classified as a LAPS by WECC, which called it the ""S" Line Scheme." Thus, the RAS received no periodic assessments. Like the SONGS scheme, the "S" Line RAS appears to be a SPS/RAS as defined by NERC, because it is an automatic protection system that took action other than isolating a faulted facility by tripping generation in Mexico for loading on a tie line between SDG&E and IID.

The "S" Line RAS was implemented for two reasons: (1) to protect IID's system from overload during an N-2 event at SDG&E's Miguel substation; and (2) to protect IID's lone 230/161kV transformer at El Centro from overloads due to generation additions at Imperial Valley substation. There is some question as to whether the scheme is still necessary, as both of the concerns that originally triggered installation of the "S" Line RAS have been mitigated. IID added a new transformer bank at El Centro, mitigating the concern for overloads on the 230/161kV transformer. Also, reconfigurations at Miguel along with the modifications to a RAS at Miguel have mitigated the concern of adverse effects on IID's system as a result of an N-2 event at Miguel. Since LAPSs are not periodically reviewed, the arguably outdated "S" Line RAS was still active during the September 8th event, and its operation contributed to IID's uncontrolled separation and the operation of the SONGS separation scheme by tripping over 400 MW of generation before the "S" Line itself tripped. At a minimum, SDG&E, IID and CAISO should participate in the review of the "S" Line RAS.

The SPSs that operated during the event suggest that WECC's previous exclusion of certain NERC-defined SPSs from WECC's RAS definition had an adverse impact on BPS reliability.

Finding 23: Effect of Inadvertent Operation of SONGS Separation Scheme on BPS Reliability:

The simulation of the event shows that the inadvertent operation of the SONGS separation scheme under normal system operations could lead to a voltage collapse and blackout in the SDG&E areas under certain high load conditions.

Recommendation 23:

CAISO and SCE should promptly verify that the inadvertent operation of the SONGS separation scheme does not pose an unacceptable risk to BPS reliability. Until this verification can be completed, they should consider all actions to minimize this risk, up to and including temporarily removing the SONGS separation scheme from service.

A simulation was conducted to evaluate what would happen if the SONGS separation scheme inadvertently operated during normal system operations (e.g., in the absence of any outages, overloads, or SOL violations). Based on this simulation, it was determined that under certain high load conditions, the operation of the scheme could result in voltage collapse and a blackout in SDG&E's and CFE's territories. A voltage stability study was conducted using a Power-Voltage (P-V) curve to estimate the amount of SDG&E load that could reliably be supplied after an inadvertent operation of the SONGS separation scheme.

Specifically, the system is most likely to collapse when the SDG&E load exceeds 3,500 MW. In 2010, SDG&E's load exceeded this amount for 851 hours, meaning that the system was exposed to a potential blackout for approximately 10% of the year. This shows the potential risk to BPS reliability during normal system operations as a result of the inadvertent operation of the SONGS separation scheme. Accordingly, given the lack of studies done on the scheme, it was recommended that the inadvertent operation of the SONGS separation scheme be reviewed promptly to ensure it does not pose an unacceptable risk to BPS reliability. Until this verification can be completed, CAISO and SCE should consider all actions needed to minimize this risk, up to and including temporarily removing the scheme from service.

Moreover, if SCE and CAISO were to decide to temporarily remove the scheme from the service, FERC/NERC does not believe that BPS reliability would be jeopardized. Simulations conducted for the day of the event show that if the scheme had not operated, the system, with the exception of collapses in the IID and Yuma areas, would have stabilized with minor overloads in the area around SONGS, acceptable voltages in the SDG&E area, and sufficient reactive margins in the critical portion of SCE's system.

Finding 24: Not Recognizing Relay Settings When Establishing SOLs:

An affected TO did not properly establish the SOL for two transformers, as the SOL did not recognize that the most limiting elements (protective relays) were set to trip below the established emergency rating. As a result, the transformers tripped prior to the facilities being loaded to their emergency ratings during the restoration process, which delayed the restoration of power to the Yuma load pocket.

Recommendation 24:

TOs should reevaluate their facility ratings methodologies and implementation of the methodologies to ensure that their ratings are equal to the most limiting piece of equipment, including relay settings. No relay settings should be set below a facility's emergency rating. When the relay setting is determined to be the most limiting piece of *equipment, consideration should be given to reviewing the setting to ensure that it does not unnecessarily restrict the transmission loadability.*

TOs are required to designate and share their facilities' SOLs. An SOL is the value that satisfies the most limiting element of a facility beyond which the system cannot operate reliably. The relay loadability calculations show that APS failed to properly establish the SOL for two of its 500/69 kV transformers in North Gila, because the transformers' relay loadability or load limit was actually set below their emergency ratings. A facility cannot operate above its relay load limit, as operation in excess of a load limit results in the facility being removed from service. Thus, these settings prevented the TOP from taking advantage of the short term emergency ratings identified by the transformers' SOLs. These settings resulted in difficulties restoring power to the Yuma load pocket, as operators believed they could load the transformers up to their emergency rating. Instead, the transformers tripped below the emergency rating, delaying the restoration of power to Yuma.

If the SOL derivation had considered the transformer relay load limit, the TO could have (1) provided an SOL that accurately reflected the relay load limit so the system operator could have limited the transformer loading appropriately, or (2) reviewed the relay load limit to determine whether it unnecessarily limited the transformer loadability, and if so, raised the transformer relay setting threshold above the transformer emergency rating while coordinating the setting with the transformer short-time thermal capability.

Load-Responsive Phase Protection Systems Set Too Close to Normal or Emergency Ratings

BES facilities at a minimum are required to have normal and emergency ratings. The normal rating is a continuous rating or a rating that a facility can be operated to on a daily basis that specifies the amount of electrical loading a facility can support. The emergency rating specifies the level of electrical loading a facility can support for a finite period of time. Operating a facility beyond its normal and/or emergency rating for an extended period of time will expose certain equipment in that facility to the risk of thermal damage. In order to prevent thermal damage to facilities, some TOs implement overload protection systems that are designed to automatically isolate the facilities if operated beyond their emergency rating.

A problem arises when overload protection systems are set in close proximity to a facility's normal or emergency ratings. Setting the overload protection close to the normal or emergency ratings restricts facility loading and prevents operators from having sufficient time to take remedial action to mitigate an overload before the facility is automatically isolated by the overload protection system. As the Commission stated in Order No. 733, "manual mitigation of thermal overloads is best left to system operators, who can take appropriate actions to support Reliable Operation of the Bulk Power System." Protective relay settings limited transmission loadability with extremely conservative overload protection settings, resulting in cascading outages during the September 8th event. These settings resulted in facilities being automatically removed from service by relays before operators had an opportunity to take remedial action.

Finding 25: Margin Between Overload Relay Protection Settings and Emergency Rating:

Some affected TOs set overload relay protection settings on transformers just above the transformers' emergency rating, resulting in facilities being automatically removed from service before TOPs have sufficient time to take control actions to mitigate the resulting overloads. One TO in particular set its transformers' overload protection schemes with such narrow margins between the emergency ratings and the relay trip settings that the protective relays tripped the transformers following the N-1 contingency.

Recommendation 25:

TOs should review their transformers' overload protection relay settings with their TOPs to ensure appropriate margins between relay settings and emergency ratings developed by TOPs. For example, TOs could consider using the settings of Reliability Standard PRC-023-1 R.1.11 even for those transformers not classified as BES. PRC-023-1 R.1.11 requires relays to 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.

Relay loadability calculations indicate that the relay settings on a number of transmission facilities limited transmission loadability to slightly above the emergency rating. For example, the relays on IID's CV transformers were set to trip at 127% of their normal rating. The parallel CV transformers were loaded to 130%, which was above their 127% overload relay trip point, immediately after the loss of H-NG. Both transformers tripped less than 40 seconds later. If the transformers' overload trip point had been in accordance with PRC-023-1 R.1.11, the trip point would not have been exceeded immediately after the loss of the H-NG, and IID operators might have had time to take actions to prevent cascading.

During the September 8th event, IID was unaware that the overload relay setting for the Ramon 230/92 kV transformer had been mistakenly set at 207% of its normal rating. IID intended the Ramon transformer to have been set to trip at 120% of its normal rating. After the event, IID reduced the Ramon transformer's trip setting 207% to 120%, making it more likely to trip during high-loading conditions or conditions similar to those that precipitated the blackout, decreasing the opportunity for its operators to take mitigating actions during such conditions. This setting actually increased the risk of future cascading outages like the one which occurred on September 8, 2011.

Finding 26: Relay Settings and Proximity to Emergency Ratings:

Some TOs set relays to isolate facilities for loading conditions slightly above their thirty minute emergency ratings. As a result, several transmission lines and transformers tripped within seconds of exceeding their emergency ratings, leaving TOPs insufficient time to mitigate overloads.

Recommendation 26:

TOs should evaluate load responsive relays on transmission lines and transformers to determine if the settings can be raised to provide more time for TOPs to take manual action to mitigate overloads that are within the short-time thermal capability of the equipment instead of allowing relays prematurely isolate the transmission lines. If the settings cannot be raised to allow more time for the TOPs to take manual action, TOPs must ensure that the settings are taken into account in developing facility ratings and that automatic isolation does not result in cascading outages.

In addition to the problematic protection settings of the CV transformers, which precipitated the cascade, the inquiry discovered that several other facilities, including a number of IID's 161 kV transmission lines and two of WALC's 161/69 kV transformers had relay protection settings which were only slightly above those facilities' emergency ratings. These conservative settings severely limited TOPs' response time before the facilities were isolated, preventing the operators from taking effective mitigating action against the cascade. It is unknown whether less conservative relay settings on these other facilities would have mitigated the cascade, the applied settings nevertheless do not leave operators sufficient time to take mitigating steps to prevent or ameliorate the consequences of future events.

Angular Separation

When a transmission line trips or goes out of service, the phase angle will generally increase between its two terminal points. When angle differences become large, facilities connected to the system can lose synchronization, causing the system to become unstable. Also, if the phase angle is too large, closing the line breaker back into service with a large angle difference may result in damage to nearby generator turbine shafts, and the resulting power swings and oscillations could lead to system instability or collapse. To enable successful reclosing, studies should be run to determine the maximum phase angle difference allowable for a line to be closed back in and safeguards be put into place to prevent reclosure with excessive phase angle differences. Should the phase angle difference exceed the established limit, generation or load must be adjusted to reduce it to the level that allows the line to be closed.

Finding 27: Phase Angle Difference Following Loss of Transmission Line:

A TOP did not have tools in place to determine the phase angle difference between the two terminals of its 500 kV line after the line tripped. Yet, it informed the RC and another TOP that the line would be restored quickly, when, in fact, this could not have been accomplished.

Recommendation 27:

TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operation for reclosing lines with large phase angle differences. TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses that address the angular differences across opened system elements.

The simulation shows that after H-NG tripped, the voltage phase angle between the two terminals increased from 20 degrees to approximately 72 degrees. On the day of the event, APS's synchro-check relay was set at 60 degrees, meaning APS would not have been able to reclose H-NG until it reduced the phase angle difference from 72 to 60 degrees, or changed the relay setting to allow the breaker to close. Specifically, the 60 degree setting would not have allowed APS to reclose H-NG until appropriate generation on both sides of North Gila was dispatched or load reductions in the areas west of North Gila were implemented to reduce the difference of the voltage phase angle to 60 degrees.

Although APS operators are trained to effectively respond to phase angle differences, APS currently lacks the tools necessary to determine phase angle differences following the loss of a transmission line until the line is reenergized. The training, therefore, does little good if the operators cannot determine whether a phase angle difference exists in the first place. Generally, APS operators can monitor phase angles through SCADA, but in order to receive and review this data, the transmission line must be energized. After H-NG tripped, and prior to reenergizing the line, for example, APS had no way to know if the line could be reclosed within the permissive 60 degree setting of its synchro-check relay. It lacked situational awareness of the phase angle difference. Yet, APS informed WECC RC and CAISO that it believe3d the line could be reclosed quickly, when, in fact, this could not have been done due to the phase angle difference.

To avoid a similar situation in the future, TOPs should ensure that they have adequate tools to determine phase angles after the loss of transmission lines. For example, they can install PMUs throughout their system, as APS plans to do their situational awareness of phase angles. Moreover, TOPs should ensure that their operators are trained to respond to phase angle differences by, for example, re-dispatching generation. In addition, TOPs should not underestimate the time required to reclose a line, particularly without first knowing the phase angle difference. Here, for example, APS likely could not have reclosed the line quickly, even had it know the phase angle difference, given system conditions on the day of the event.

Indeed, by conducting a series of power flow simulations it was found that significant amounts of generation re-dispatch were needed to close the phase angle difference. The dispatched approach adjusts the available generation nearest the Hassayampa and North Gila buses. As generation is dispatched to its maximum output in the vicinity of the two stations, other generators farther out are adjusted to effect the change in voltage phase angles.

With the particular conditions of the September 8th event, approximately 1,800 MW needed to be re-dispatched on both end of H-NG (and close to the terminals, in Southern California and Arizona) in order to close the voltage phase angle from 72 degrees to 60 degrees (i.e., to within the permissive 60-degree setting of the synchro-check relay.) More generation – more than twice as much – must be re-dispatched if units are chosen in Northern California to close the angle between Hassayampa and North Gila.

While system operators could re-dispatch generation from available spinning reserves or commit units in Southern and/or Northern California area, it is questionable how quickly 1,800 MW could be dispatched.

Summary

In this course we have looked at the causes of the September 8, 2011 outage and the 27 findings and recommendations of the study committee. Unfortunately, the September 8th outage shares some of the same characteristics of the earlier August 14, 2003 outage in the Eastern Interconnect. Both outages had root causes that included: Inadequate long-term and operation planning; inadequate situational analysis of real time events; and protective relay schemes that may have accelerated the outage.

The electric power system is a complex machine with vast interconnectivity. Developing procedures to prevent future events such as the September 8th event is a worthy – though likely unattainable – goal; Widespread voltage collapse events will happen again.

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