California Public Utilities Commission
Safety and Enforcement Division
Staff Report

Southern California Edison Company
General Rate Case, 2015-2017
Application 13-11-003

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EXECUTIVE SUMMARY

The California Public Utilities Commission (CPUC) Safety and Enforcement Division (SED) staff prepared this report on Southern California Edison Company's (SCE) General Rate Case (GRC) Application requesting authority to, among other things, increase its authorized revenues for electric service in 2015, and to reflect that increase in rates.

This SED staff report is made in response to an Assigned Commissioner's Ruling and Scoping Memo directing SCE to identify within its GRC Application the top ten risks, the strategies proposed to mitigate those risks and the alternatives considered.

SCE did not employ a risk-based approach in the design of its GRC Application. This SED staff report first provides general insights into SCE's implicit risk approach, and then provides technical insights into five of the ten risks identified by SCE. While critical in the final evaluation of the GRC Application, this SED staff report does not opine on funding levels associated with any project.

SCE has identified the top 'threats' to its system but has not yet taken the next step of systematically quantifying those threats into 'risks', both in terms of probability or consequence of occurrence. SCE relies on the informed judgment of its subject matter experts when discussing risk, but those risks are not yet fully calibrated across different business units.

The SED staff report provides technical insights and analysis on five of the ten top risks identified by SCE, thematically concentrating on the transmission and distribution aspects of its system. Given constrained resources and timelines, SED staff elected to focus its efforts on these threats: conductor failure, pole failure, underground structure failure, other electric equipment failure and physical & cyber security. For each risk, SED staff identifies the data and information available to make an informed risk assessment.

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INTRODUCTION AND BACKGROUND

The Assigned Commissioner's Amended Scoping Memo in Application (A.)13-11-003 states "safety and reliability are the foundation of the Commission's review" of this application. The Scoping Memo continues to state "the principle of safety necessarily includes its counterpart of risk management: the identification of risks through established methods, assessment of the nature of risks, and the prioritization and mitigation of risks." In response to these statements, the California Public Utilities Commission (CPUC) Safety and Enforcement Division (SED) staff has drafted this report focusing on Southern California Edison Company's (SCE) proposal in this General Rate Case (GRC) for 2015-2017.

SED staff provides this report with the express aim of providing an evaluation of the risk assessment and risk management methodology used by SCE in preparing this GRC Application.

Staff's evaluation consists of two main parts. The first part is a brief review of the risk identification and risk management methodology used by SCE in its GRC Application. This first part will also discuss evaluation criteria developed by Cycla Corporation to evaluate the strength of the risk assessment/management program. The second part is a selective review of the top 10 threats identified by SCE. While this report does review certain projects, it makes no recommendations and offers no opinions on the underlying merits of any particular project. Rather, SED staff focuses on technical matters and on underlying risk management methodologies employed by SCE.

As highlighted in the Scoping Memo, the overlapping concepts of safety, risk, reliability and resiliency are all interwoven in SCE's application. This report is premised on three critical steps to examine SCE's application:

1) Risk Identification
2) Risk Assessment
3) Risk Management

Risk is classically defined as the probability of an event (in this context, a hazard or a threat to SCE's electric generation, transmission or distribution system) occurring multiplied by the consequence (or impact) should that event occur. Risk assessment involves the analysis of data to identify which hazards/threats present the greatest risk to the system. Risk management is the process by which the organization responds to the identified risk. We note that risk can never be eliminated, but rather a risk can only be mitigated down to an acceptable level. The value in risk assessment is derived from systematically identifying risks and prioritizing them based on their impact and likelihood of occurrence. Following identification and ranking of risks, the next step is to determine the suite of candidate risk mitigation measures. The operator then selects the mitigation measure which best "fits" the assessed risk. Selecting a mitigation strategy should include an evaluation of best practices and available technologies. Selecting between the various different mitigation options should factor in both relative cost and benefits and also the operator's knowledge and perspective of that particular part of the system.

Electric reliability, which is the ability to maintain service, is measured in outages, both momentary and sustained. In Decision (D.) 96-09-045, the Commission adopted three metrics:

- SAIDI – System Average Interruption Duration Index
  (minutes of sustained outage)
- SAIFI – System Average Interruption Frequency Index
  (number of sustained outages)
- MAIFI – Momentary Average Interruption Frequency Index
  (number of momentary outages)

While not formally adopted in D.96-09-045, Commission Staff also track the Customer Average Interruption Duration Index[1] (CAIDI), which relates to the average customer experience of outage duration. While reliability and safety are distinct concepts, there is inherent overlap. External events which impact reliability of the system may also create safety implications. For example, a downed wire will impact reliability but also create an acute safety situation until the line is de-energized; different protocols are needed to both keep the system reliable and to respond to the safety situation. In some situations, reliability and safety can have an inverse relationship. For instance, settings on protective devices, such as circuit breakers and automatic re-closers, can be adjusted to different levels of sensitivity and trigger if potential faults are detected. While de-energizing circuits if a potential fault is detected can be beneficial for safety, it would have adverse effect on system reliability. Therefore, the utilities in their operations and system design need to carefully balance reliability and safety considerations.

Resiliency is the electric system's ability to respond to an external event. A system that is both reliable and resilient has evident safety implications; ensuring reliability and resiliency often employ risk management techniques. Continuing the example of the downed wire from above, resiliency would be the time to restore service and remediate the situation.

With this generic vocabulary in place, we now turn to the particulars of SCE's application.

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[1] CAIDI is calculated by taking SAIDI divided by SAIFI.

PURPOSE OF THIS REPORT

The Scoping Memo asked SCE to serve supplemental testimony on three questions:

1. What risks is SCE mitigation by its proposed investments? Please identify the risks specifically and also the amount of the capital investment and/or operating and maintenance expenses that mitigate the risk the utility has identified. Please limit this list to no more than ten risks.
2. For the risks that SCE has identified, please identify the existing controls in place to mitigate these risks, and what would the additional investment achieve above and beyond these existing controls.
3. For the proposed capital investments and/or operating and maintenance being proposed, identify at least two alternatives that SCE considered, but ultimately decided to forego.

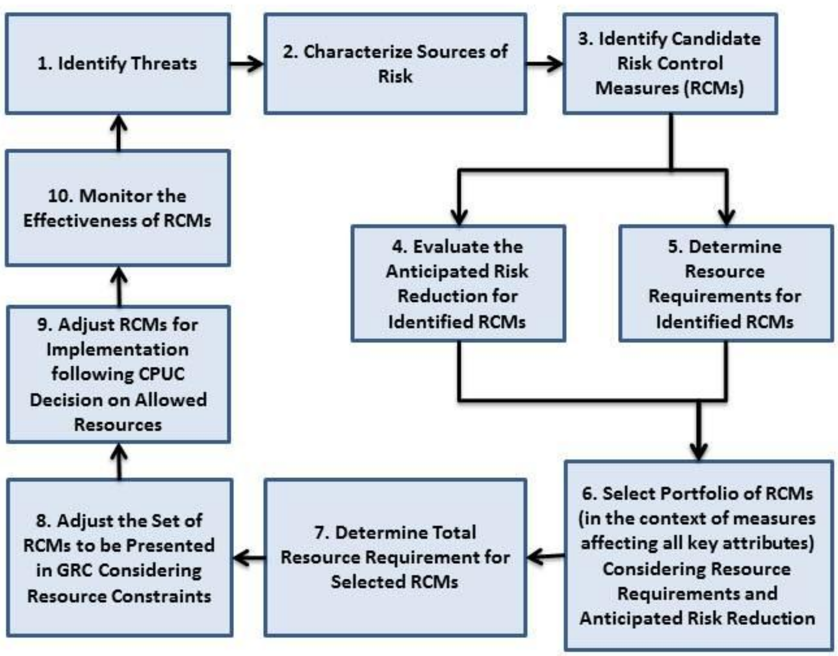
In this report, SED staff provides insights and analysis into the information SCE provides in response to these three questions posed by the Scoping Memo. SED staff acknowledges that these supplemental questions were designed to provide additional detail in SCE's underlying GRC Application; the Scoping Memo and these questions did not instruct SCE to update or amend its GRC Application using a risk management methodology. SCE did not undergo a comprehensive risk-analysis when structuring its GRC Application. The CPUC has not yet instructed SCE to integrate risk analysis into its GRC process and therefore the SED report does not evaluate SCE's performance in applying a risk management methodology. SED staff notes that the CPUC has an active proceeding on how to best integrate risk into the rate case plan, Rulemaking (R.) 13-11-006.

In this report, SED staff highlights the risk identification, assessment and management that SCE has done, both on an enterprise level and within specific projects. While SED staff encourages prudent spending, this report does not take any position on the cost effectiveness or affordability of any of SCE's proposed risk mitigation programs and projects in this GRC application. Ideally, a quantification of benefit of reduced risk exposure could be compared to the project's proposed costs. While SED staff is concerned about affordability, ultimately we did not have sufficient information or resources to provide that type of detailed analysis.

RISK ASSESSMENT AND MANAGEMENT EVALUATION

SED's evaluation of SCE's GRC Application commences with a review of SCE's approach to risk identification, assessment and evaluation. SED staff employs the criteria developed by Cycla Corporation and used during its evaluation of the Pacific Gas & Electric Company GRC, A.12-11-009. The evaluation is based on a set of 10-step criteria, which we represent graphically below.

Elements of a Risk-Informed Rate Case Development Process



Ten Criteria of a Risk-Informed General Rate Case

1) Identify the threats having the potential to lead to safety risk;
2) Characterize the sources of risk;
3) Characterize the candidate measures for controlling risk;
4) Characterize the effectiveness of the candidate risk control measures (RCMs);

5) Prepare initial estimates of the resources required to implement and maintain candidate RCMs;
6) Select RCMs the operator wishes to implement (based on anticipated effectiveness and costs associated with candidate RCMs);
7) Determine the total resource requirements for selected RCMs;
8) Adjust the set of selected RCMs based on real-world constraints such as availability of qualified people to perform the necessary work;
9) Document and submit the General Rate Case filing, on which the CPUC decides the expenditures it will allow, and, based on CPUC decision, adjust the operator's implementation plan;
10) Monitor the effectiveness of the implemented RCMs and, based on lessons learned, begin the process again.

As developed by Cycla Corporation, these ten steps can be evaluated using a series of four grading levels.

Grading Levels

A. Fully satisfies evaluation criteria
B. Substantially satisfies the evaluation criteria and provides a good foundation for future satisfaction of the criteria
C. Partially satisfies the evaluation criteria but requires substantial improvement to fully meet the criteria
D. Fails to satisfy the evaluation criteria

Observations on SCE's Risk Assessment and Risk Mitigation

SCE did not design its GRC Application using a risk based approach. In essence, the Amended Scoping Memo's questions asked SCE to characterize its top ten risks (criteria 1 and 2), risk reduction which would occur over existing practices (criterion 4) and alternatives considered to the proposals (criterion 5). SCE states[2] it is "not indicating risk levels associated with these components of the system are at levels which are imminent concern to public or worker safety." Because SCE did not design its

[2] SCE-15, page 2.

GRC Application with a risk-based framework, it is not practical for SED staff to apply the grading levels to the ten criteria outlined above. However, SED staff encourages SCE to utilize this approach in future GRC Applications; SED staff intends to use a risk-based methodology on a going forward basis.

We note that Criteria 9 and 10 are not applicable at this stage of the rate case process; both assess how SCE performs in implementing risk mitigation and monitoring future risk post-CPUC decision on this GRC Application. SED staff will track SCE's progress in mitigating identified risks and its overall development of risk assessment and risk management protocols going forward. As SCE notes in its supplemental testimony, risks evolve over time[3] and priorities will shift based on emergent information. SED staff will continue to monitor identified risks in between GRC cycles so that it can understand how shifting operational priorities will be reflected in future funding requests.

SED staff makes some generic observations about SCE's risk management approach based on the limited information provided. SED staff makes these observations both in the context of this GRC and for future Applications.

In general, SCE's GRC risk approach lacks quantification of risk (both in probability and on impact). In essence, SCE has identified its top ten "threats" to the system but has not fully taken the next step to translate these threats into risks assessment. SCE has not consistently put into context either the probability of identified threats occurring or the potential impact of the threats if they were to occur. SCE has done this for some, but not all, of its top identified 'threats'. Specifically, there is an inconsistent use of numeric calculations to define risks to the public, SCE employees and property. SCE generally utilizes informed judgment of its subject matter experts to

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[3] SCE-15, page 3.

help inform relative risks. In a limited fashion, the SCE GRC Application discusses how the project proposed will mitigate an identified and assessed threat. When possible, SCE relates that mitigation to either reliability or resiliency enhancements of its system.

In general, SCE's proposals are either "on or off" with respect to risk mitigation and enhancing reliability and resiliency. There is no discussion of incremental system benefit. In its supplemental testimony, SCE does not discuss minimum investments required to yield safety or reliability benefits, however minimum investments required to yield reliability benefits are discussed to varying degrees in SCE's original testimony. Risk mitigation is typically not 'linear' in nature, and often the benefits are a "stair step" where a certain amount of work is required before investments can yield initial benefits. SCE could improve its current risk management process by having a relative risk ranking model that enables incremental risk evaluations, since it could help balance affordability and risk reductions.

Since SCE heavily relies on informed judgment and is in the process of more fully integrating data into its risk mitigation strategies across business operational units, there is a subjective nature to both the risks presented and the determination of "acceptable level" down to which the risks can be mitigated. The more that SCE can use data to support its future proposals, the less subjectivity in balancing risk trade-offs will occur. SCE should continue down the path of developing a robust quantitative approach for both risk ranking and risk mitigation.

In the threats that SCE identifies, some impact reliability, some impact resiliency, and some impact public and employee safety. SED staff observes that SCE created this top ten list mostly in isolation, where each proposal is independent from the others, when in reality there are inherent interactions in the system. One next step which SCE should consider is how threats interact with each other. The same is true for mitigation strategies: SCE does not discuss how a fix in one system may interact and lessen a potential threat in another part of the system.

As described above, risks can never be fully eliminated, but rather they can be eliminated down to an acceptable level. At times, determination of "acceptable level" is made by the CPUC, legislation or by governing General Orders. However, more often, determination of "acceptable levels" is left to the discretion of the utility. It appears that SCE is inconsistent in how it defines its risk tolerance. While SCE does have a Risk Management Committee, SCE does not provide sufficient information and insight to its risk tolerance. SCE can further improve the risk management process by having a more robust and transparent risk tolerance threshold to determine what is an acceptable level of risk it is trying to mitigate for its proposals. Risk tolerance and risk tradeoff are foundational to risk management, whether from a theoretical viewpoint or from a practical viewpoint. SCE should explore the concept of risk tolerance in an As Low As Reasonably Practicable (ALARP) framework and supplement this framework with prudent application of industry best practices. SED staff encourages SCE to explore this concept in future GRC applications. SED staff believes that incorporating an ALARP approach to utility risk management could improve decision making with respect to the question of scope and implementation pace of the proposed programs and projects.

The last question posed by the Scoping Memo was for SCE to identify alternatives considered but ultimately decided to forego in favor for its proposed project. In general, SCE did not fully explain the alternatives rejected nor the rationale for rejecting them. Such observations are critical for understanding inherent risk trade-offs. There is inconsistent reasoning of why an alternative was rejected across these top ten risks. As a result, it is harder to ascertain what SCE considers to be an "acceptable" level of risk and if SCE mitigates risk down to a consistent threshold.

OVERVIEW OF SCE RISK ASSESSMENT & MANAGEMENT

SCE's Enterprise Risk Management (ERM) Group integrates the threats and risk assessments from each of SCE's business units (e.g. transmission, distribution, power generation, etc.) and prioritizes them on a company wide basis. Overall, SCE is in the process of integrating risk management approaches into its various business units; as a result, different levels of risk management are employed throughout the company. The ERM group, as presently structured, is approximately five years-old; SCE states that the group is in a state of transition. The origins of the group were in commodity purchasing, specifically insurance premiums. The group's emerging focus on now integrating risk management practices across the company's varying operational units. The ERM group takes the top "key" risks identified by each operational unit and prioritizes them from a company-wide point of view. Once prioritized, these key risks are presented to the company's senior leadership in a Risk Management Committee. These "key" risks may have financial, material and/ or operational impacts on the company. From the Risk Management Committee, action items are presented both to an audit committee and ultimately to SCE's full board of directors. The frequency of these meetings varies, but typically occurs twice per year.

SCE's ERM Group also acts as an internal consultant to the business units. The ERM group provides structure and consistency to the risk assessment process. It promotes and facilitates the collection and monitoring of data and metrics which each operational unit can use to identify risk. This group also conducts a series of workshops to discuss new sources of data that could be used to inform the risk management program, including metrics that could be collected during the course of normal work.

SCE's model is to have a relatively small ERM group, but to have the practices integrated into the practices and work planning of each group.[4]

The ERM group also employs the use "backcasting" which is a form of brainstorming looking back at past failures to identify possible causes and contributing factors. Backcasting is less formal that Root Cause Analysis, but can provide information for further investigation and possible use for planning purposes.

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[4] In person meeting with SED, 7/24/14.

REVIEW OF TOP RISKS RELATING TO SAFETY AND RELIABILITY

SCE is on a path to move towards a more objective, data driven risk management program. For some of the top risks identified, SCE relies heavily on subject matter experts and nascent inspection and data gathering programs. In other programs, there is more historical failure data available to perform risk assessment and management. In its Supplemental Testimony, SCE identifies the following ten categories as its top risks:

1. Conductor Failure
2. Pole Failure
3. Underground Structure Failure
4. Other Electric Equipment Failure
5. Workforce Safety and Worker Capability
6. Physical and Cyber Security
7. Emergency or Catastrophic Incident
8. System Capability
9. Energy Supply
10. Information Systems Infrastructure

In this report, SED staff reviews the risk assessment, current practices and alternatives (as requested by the Scoping Memo) for these top risks, with emphasis placed on the first four categories and on physical and cyber security. The report primarily focuses on the sources of information and data available to conduct risk assessments.

SED staff notes that a lot of the enterprise risk management functions rely on information management systems. SCE has made extensive requests in its GRC Application for enhancements to its Information Technology (IT) systems. In part, these systems are captured in SCE's tenth top identified risk. While SED staff did not have the resources available to consider this request, we note that proper information and data analysis requires these resources in order to conduct risk management.

Conductor Failure

Conductor failure is a failure of distribution primary wires, which are commonly referred to as conductors for overhead lines and cables for underground lines[5]. We now discuss the SCE programs and sources of data and information available to evaluate risk related to conductor failure.

The Overhead Conductor Program

In 2013, SCE implemented the Overhead Conductor Program[6] (OCP). The program drivers include:

- Preempt wire down (WD) incidents through proactive inventory, analysis, inspection, maintenance, and remediation of overhead conductors.
- Identify root causes of WD working with SCE Engineering and Root Cause Investigation Teams.
- Use the Pole Loading Program to integrate and execute OCP

SCE collects data from engineering studies, root cause analysis evaluations about WD incidents, overhead conductors, splices, connectors, switches and branch line fuses. SCE studies a variety of locations across its territory; areas were selected by speaking with local planning departments and SCE troublemen to identify areas prone to outages and areas that are known to have splices. A total of 1309 spans were surveyed, which included a variety of coastal construction, old construction, new construction, main lines, tap lines, commercial areas and residential areas. The data from these inspections is used to develop statistics which can inform SCE's risk program. Based on the results of the pilot program and the problem areas identified, SCE's Maintenance & Inspection and Engineering groups revised the list of data to be gathered in future overhead conductor inspections.

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[5] See SCE-15, page 15.

[6] Overhead Conductor Program (OCP) Pilot Summary and Next Steps, Maintenance & Inspection, dated September 25, 2013.

<u>The Distribution Inspection & Maintenance Program</u>

In 1997, General Order (GO) 165 was adopted which requires distribution equipment inspection and reporting standards. In 2004, the CPUC issued D.04-04-065 (Maintenance OII Decision), in Order Instituting Investigation I.01-08-029 (Maintenance OII). In the Maintenance OII Decision, the CPUC directed that SCE, in consultation with the CPUC staff, refine its five-level maintenance priority system. SCE worked with CPUC staff and other CA utilities to develop the common platform for this program, which is codified in GO 95 Rule 18A. The culmination of SCE's work with CPUC staff led to the deployment of SCE's new Distribution Inspection and Maintenance Program[7] (DIMP) on January 1, 2008. The DIMP emphasizes a condition's risk to safety and reliability from a much broader perspective, reduces the need to allocate resources on those conditions that pose little or no safety or reliability risk and allows SCE to concentrate its resources and work on appropriately prioritized conditions, consistent with the Commission's direction in the Maintenance OII Decision[8].

SCE has 4300 distribution circuits consisting of 86,000 distribution line miles, 330,000 distribution underground structures and 1.5 million wood utility poles. The GO 165 inspection minimum inspection requirements for overhead facilities are:

- Annual circuit and streetlight patrols (bi-annual for rural circuits)
- Detailed inspections of equipment once every 5 years for overhead/pad mounted facilities
- Detailed inspections of equipment once every 5 years for underground (subsurface) facilities
- Intrusive wood pole inspections
- First Inspection within 25 years

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[7] SCE DIMP PowerPoint Handout from Mel Stark, SCE Manager of Maintenance and Inspections.

[8] Southern California Edison Company's (U 338-E) Annual Report of 2010 Distribution Inspection and Corrective Actions Submitted Pursuant to General Order NO. 165.

- Re-Inspection every 20 years (for safety reasons, SCE has voluntarily decided to re-inspect poles on a 10 year cycle based on a grid system)
- Underground facilities are inspected on a 3 year cycle
- Requires annual reporting of performance

SCE's program parameters to meet these requirements include:

- Annual patrols of over 4600 circuits per year and over 740,000 street lights per year
- Overhead Detail Inspections averaging over 280,000 poles per year
- Underground Inspection of over 150,000 underground structures per year
- Intrusive pole inspections averaging over 130,000 poles per year

SCE has a Worst Circuit Rehabilitation (WCR) program, which is its primary process for developing specific remediation plans for circuit reliability issues. This is a targeted reliability improvement program. It minimizes the negative impact of infrastructure aging on overall system reliability and it minimizes the disparity between levels of reliability received by customers served by different circuits. The WCR program identifies circuits that are disproportionately high in terms of their contribution to system SAIDI and SAIFI. Circuit rehabilitation typically involves replacement of each circuit's most risk-significant mainline cable. Not all circuits are in equal need of rehabilitation; in 2012, about 7% of SCE's circuits were responsible for approximately 50% of the systems SAIDI.

Asset Management and System Reliability

SCE's Asset Management and System Reliability[9] group (AMSR) is responsible for establishing a long-term strategy for managing distribution system reliability through asset management. AMSR maintains records of distribution assets, tracks distribution system and circuit reliability, identifies actual and probable performance trends, and drafts cost-effective corrective actions where indicated. AMSR maintains

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9 SCE-03, Volume 4.

records on major substation equipment, analyzes historic performance, assesses risks of future in-service failures, and develops long-term infrastructure replacement strategies.

AMSR evaluates outage records to identify the worst performing circuits.

Some of the data sets used to identify the "worst performing circuits" are:

- System SAIDI, System SAIFI, Circuit SAIDI, and Circuit SAIFI
- The number of cable failures in a given year
- The number of customers who had repeat outages on a given circuit
- Circuit maps and records to find equipment failures over the last 3 years

SCE then checks with its staff in the field to see if, based on their experience, they agree with the circuits labelled as the "worst performing circuits". The most risk significant equipment/infrastructure in the worst performing circuits is identified for replacement. SCE indicates that usually only about 20% of any given circuit needs to be rebuilt[10].

In addition to the replacement of aging infrastructure, circuit enhancements, (e.g., automation, the addition of automatic re-closers and radial fuses, and the elimination of "chokers"[11]) may also be identified wherever cost-effective.

SCE is planning to use CYME International T&D power system software to create real time models of circuits. This enables SCE to test planned improvements to circuits before actually installing the modifications.

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[10] In person meeting with SED, 7/24/14.

[11] A "choker" is a segment of cable that is too small to carry the amount of power we would like to send through it. We often find chokers at the end of a circuit where the cable is smaller and where we have tied that circuit to an adjacent circuit in order to provide a backup source of power. If the cable near the tie is too small, the adjacent circuit can back up only a portion the circuit. Replacement of the choker cable can allow the adjacent circuit to carry a much larger portion of the circuit. This can have a significant impact on reliability.

Cable Failure and Testing

Cable in conduit (CIC) was installed in the 1960's and constitutes about 13,000 miles (or approximately 25%) of SCE's cable. The cable came from the factory already installed in polypropylene tubing (conduit). Although cost-effective to initially install, the cable has been found to be very difficult to remove from the tubing after a failure. Replacing the cable requires re-trenching, which requires a significant expenditure. As a result, SCE investigated cable testing methods and now has The Testing-Based Cable Life Extension Program. The program uses the partial discharge method of testing. It is performed by first taking the cable out of service, then creating a voltage in the cable equal to twice the cable's normal voltage. If no voltage leaks from the core conductor to the neutral conductor at the exterior of the cable, the cable passes the test. Cable segments which test "good" are guaranteed by the testing vendor not to fail in service for at least ten years. Cable segments which test "bad" are scheduled for replacement. Based on the failure rates, SCE expects 50% of what is tested to require replacement, which translates to 175 conductor-miles per year.

SCE is employing new method of rehabilitating CIC, by pumping lubricant in the conduit and pulling the old cable out. This is replaced with a specially designed cable that can be reinserted into the existing conduit. This new process is more cost effective than SCE's prior method, which was to run new cable in rigid ducts in parallel to de-energized existing cable.

SCE states that partial discharge testing has been found to be a cost effective method of managing aging conduits by avoiding replacing cable which has substantial remaining life. In addition, the risks to the public, reliability and property damage caused by a cable failure are mitigated. It is also important to note that replacing a cable is much more expensive to do on an emergency basis after it fails than on a pre-emptive basis.

Pole Failure

According to SCE[12], "the risk of pole failure is driven by several factors including the deterioration and age of the pole, the amount of load put on the pole by SCE and other utility equipment, and external factors such as third party damage or natural hazards". SCE continues to state that "one pole failing can potentially cascade to multiple pole failures when conductors attached to adjacent poles pull them down. This amplifies the safety and reliability impacts of pole failure events." We now discuss SCE's programs related to pole failure and the sources of data and information available to evaluate the risk of pole failure.

Pole Loading Program

The Pole Loading Program, which began in 2014, is a comprehensive assessment and remediation plan to address pole loading risk in SCE's service territory. It involves 1.5 million utility poles, of which one half are located in high fire and/or high wind areas. Currently, SCE has approximately 240 people who physically inspect the poles to document the as-built configuration of the poles and the services attached to them. The inspection results are then used to update the pole loading calculations. SCE employs a 2 pass system of inspections, which minimizes the probability of issues being missed. The inspection results of this program are used to input the as-built loads (including wind load) and physical configuration of the poles into a computer program called SPIDA CALC which analyzes the stresses on each pole. This program is discussed further below. SCE's first priority is to assess poles in high fire and/or high wind areas. This effort is scheduled to be completed in approximately 3-1/2 years. The assessment of all poles in the program is scheduled to be complete in 7 years.

[12] SCE-15, page 24-25.

Pole Loading Study

In D.12-11-051, the CPUC ordered SCE to perform a pole loading study[13] on a statistically valid random sample of poles across SCE's service territory. The sample of poles was chosen in proportion to the prevalence of poles in various areas of the service territory such as high wind areas, high fire danger areas, etc. Pole failure rates were developed as a result of this study. It is important to note that the failures were calculated failures and not physical failures. In other words, the failure was due to the fact that the calculated stresses in the poles were higher than the allowable stresses. Note that allowable stresses include a margin of safety to provide additional protection from physical failure. New poles going into service have a design safety factor of 4.0. Poles already in-service have a design safety factor no lower than 2.0. Steel poles are designed with a safety factor of 1.5.

The study was comprised of 5,000 pole loading calculations, of which 3,000 were chosen at random and 2,000 were used to supplement the sample. SCE hired a consultant, IJUS to perform the pole loading calculations. The calculations resulted in 77.7% of the poles passing, meaning the actual stresses in poles and guy wires were less than the allowable stresses. 22.3% of the poles failed for various reasons such as bending, buckling or guy wire stresses above the allowable stresses.

In several areas, the study goes beyond the requirements of D.12-11-051. For example, in addition to conducting a statically valid survey as required, SCE also conducted a statistical strata survey which broke down the results into several categories including requirements of GO 95, SCE internal loading standards and Fire Risk Areas. As follow up to the completion of this study, SED recommended that SCE

[13] SCE's presentation entitled, "SED Briefing on Pole Loading Program, July 24, 2014."

take several additional steps. We repeat these recommendations[14] in this report, and note certain follow up items which have already occurred. The first SED staff recommendation was that SCE conducts a wind analysis to determine the wind conditions in its service territory. Wind is a significant factor in pole loading and accurately known wind conditions should be used to help ensure that poles are designed and maintained directly. SCE hired Reax Engineering to conduct a wind study to provide the wind loading used in the Pole Loading Program. The wind study is now complete. Second, SED staff recommended that SCE should conduct a pole loading analysis of all poles to which SCE facilities are attached in order to determine compliance with both SCE internal requirements and GO 95. SED staff recommended that all poles be analyzed over the next ten years. As noted above, SCE is on track to make this timeline per the Pole Loading Program proposed in the GRC Application. Third, SCE should prioritize poles utilizing a risk management program. The risk management program should consider, at minimum, whether the pole was in a high fire threat area, the number and effect of communication facilities attached to the pole, the failure rate of poles in the area, based upon the loading study. As discussed above, SCE has taken a risk management approach in the Pole Loading Program proposed in the GRC Application. Fourth, SCE should commence mitigation procedures as soon as possible. As discussed above, SCE's Pole Loading Program proposal meets this requirement. Last, SED staff recommended that SCE work with other parties whose facilities are also attached to the poles to ensure that they are aware of internal pole loading requirements and to coordination mitigation to ensure that all portions are conducted in a timely manner. Information available to SED thus far confirms that SCE is making best faith efforts on this front.

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[14] The SED Letter, dated November 7, 2013, was issued in response to D.12-11-051, Ordering Paragraph 18. A copy of that letter was sent to the service list A.10-11-015.

SPIDA CALC Computer Program

SPIDA CALC is a graphical interactive stress analysis program used by IJUS Consulting for evaluating utility poles. It was used by IJUS to assess the utility poles in the 2012 GRC Pole Loading Study and is currently being used in SCE's Pole Loading Program[15]. Actual attachment loads, guy wires and pole configurations from the inspections performed in the Pole Loading Program and wind loads from the Wind Study are input into SPIDA CALC. The program uses a Graphical User Interface which allows the user to see a graphical depiction of the pole, cross-members, guy wires and attachments, along with the current actual stresses due to the attachment loading and wind loading. Changes to the loads and physical configuration of the pole can be made on the screen causing changes to the actual stresses shown on the screen.

The Quality Control group within SCE inspects a statistically significant sample to verify the accuracy of the pole calculations. All pole calculations are kept in a computer database which allows engineers to easily modify pole configurations and calculations if pole changes occur in the future. Currently, there are over 20,000 poles in the database. The next step in the data management aspect of the program will be to allow the SPIDA CALC software to link to SCE's SAP asset management system. If SCE is able to link the two software systems, modifications to a pole in the SPIDA CALC program could then automatically update asset characteristics in SAP asset management system and generate a work order to send crews to make the necessary modifications to the pole.

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[15] SED staff was given a demonstration of the program on 7/24/14.

The Aged Pole Program

SCE has analyzed historical data and found that poles over 70 years old have an 80% chance of failure. As a result, in 2013 SCE initiated the Aged Pole Program[16] to increase its operational capability to support the Pole Loading Program. The Aged Pole Program targets the replacement of poles aged 70 years or older. SCE indicates that the mean time to pole replacement is 62 years.

SCE states that the Pole Loading Program, which includes the Aged Pole Program, will result in a 400% increase in pole replacements.

Pole Failures Due to Vehicle Collisions

In its testimony, SCE states[17] "poles are exposed to a wide range of natural and human hazards, and can fail due to vehicles hitting a pole, large tree branches or trees falling, higher than normal wind, fires, and flash floods. For example, in 2012, 368 out of 546, or 67 percent of pole related outages were due to hits by vehicles."

If SCE can mitigate the damage from vehicle hits, it could lead to a large decrease in wires down and the risk to personal safety, property damage and reliability. Analysis of the collision data may show that certain poles and/or areas have repeat vehicle collisions. Possible mitigation steps could include reinforcing the base of poles, relocating poles, lobbying cities to reduce speed limits in certain areas, etc. SCE indicated that there is a serious effort under way to analyze the collision data for both poles and pad mounted equipment.

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[16] SCE's presentation titled, "SED Briefing on Pole Loading Program, July 24, 2014."
[17] SCE-15, pages 25-26.

Joint Pole Committee

SCE is a member of a 35 member Joint Pole Committee. The members consist of communications companies and utilities that own utility poles or rent space on them. The goal of the committee is to improve pole calculations by sharing pole loading calculations and developing a common calculation methodology and assumptions.

Pole Inspections for Erosion/Washout

It is important for poles to remain sufficiently buried to support the loads they're designed to carry. Poles are inspected on an approximate 2 year cycle to monitor the base of the pole for erosion to ensure that they remain buried in accordance with SCE standards. SCE tracks this information and includes it in its replacement programs.

Underground Structure Failure

Vaults, manholes, and other reinforced concrete underground structures house "equipment[18] such as cable, cable splices, transformers, and switches, and provide access for inspections and repairs." When SCE indicates that underground structures may fail, it refers to the potential failure of the structure itself or of the equipment inside the underground structures.

In addition, there are related risks with maintaining and operating the equipment given the limited access and confined spaces within underground structures. Such failures may occur due to deterioration or structural damage, which may be caused by various factors including water intrusion. External factors may also damage underground structure or the equipment, including the passing of heavy vehicles overhead or from dig-ins.

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[18] SCE-15, pages 31-32.

SCE states that "many of its underground structures are located in public spaces, under streets, sidewalks, and parking lots." Since the vault deteriorates over time, it can fail without notice and can lead to collapse of road surfaces, sidewalks, or structures around the vault. Violent equipment failure in the confined space of a vault poses substantial danger when the energy released by the equipment failure damages the vault structure, causing surface cave-ins, and ejection of vault lids and debris. These types of failures can result in injuries to pedestrians and traffic accidents. The confined spaces within underground structures can be dangerous to workers as demonstrated by Occupational Safety and Health Administration (OSHA) regulation of operations in these areas. In 2013, SCE reported two incidents involving worker fatalities during work performed in underground vaults.[19]

Failure of underground electrical equipment, either due to physical collapse of the structure or due to equipment malfunctions, leads to outages. Such outages last longer than other types of unscheduled outages because repairs on underground equipment and structures are more time-consuming, given the underground structure's inherent limited access.

We now discuss SCE's programs and sources of data and information to evaluate the risk associated with underground structure failures.

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[19] Incidents are currently under staff investigation:

- On April 25, 2013, an SCE employee working in an underground vault located on Murrieta Rd, in the city of Riverside, was fatally injured when a flash occurred inside the vault.
- On September 30, 2013, a crew for CAM Electric (an SCE contractor), was testing cables in an underground vault located at 16282 Tisbury Circle, in the city of Huntington Beach, when a fire started resulting in one fatality.

Underground Detailed Inspections

SCE conducts underground detail inspections[20], field investigations, and transmission underground inspections to assess the condition of equipment and structures. SCE performs Underground Detail Inspections (UDI) on the distribution system every three years for all underground equipment; SCE's UDI include underground structures that do not contain equipment. This program involves activities for inspecting SCE's underground distribution electrical system in accordance with GO 165 and DIMP. The purpose of UDI is to provide close proximity examination of underground and pad mounted distribution equipment as mandated by GO 165. Inspectors assess subsurface and pad mounted equipment including enclosures, switches, transformers, visible cables, and associated components to identify safety hazards and non-conformances with GO 128. Inspection methods for electrical equipment in underground structures may include visual inspection, thermography, oil sampling and others. The UDI inspectors document safety and reliability hazards and prioritize corrective actions in accordance with SCE's DIMP. When possible, they perform routine maintenance or make repairs during the course of the inspection.

UDI activities are generally performed by a crew consisting of a lineman and a groundman, both of which have received specialized training to work in underground vaults and in proximity to energized high voltage equipment. During these inspections, underground distribution structures that are identified as requiring additional assessment due to deterioration or other structural or equipment issues observed by the inspector are scheduled for field investigations. Damage or corrosion must not be in excess of MC860 guidelines, the SCE Standard for Underground Structures. Field investigations are performed by personnel with structural engineering expertise who

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[20] SCE-03, Volume 06, Part 1, pages 12-13.

can determine whether these structures pose a safety or reliability risk and must be repaired or replaced. Transmission underground inspections[21] are performed on transmission equipment and structures to assess the condition of the assets and determine if repairs or replacements are necessary. UDI also identifies repairs or replacements for other miscellaneous equipment contained within the underground structures. These are performed in accordance with GO 165 standards under preventive maintenance programs included in the following section on Other Equipment risk.

The results of the inspections are used to determine whether the structure needs repair or shoring to stem the degradation, if it would be cost effective in the long term to perform these repairs, or if replacements are required. Historically, 39 percent of SCE's field investigations in any given year result in vault replacements, and 61 percent result in vault repairs. Additionally, 24 percent of the vaults identified for replacement will require shoring to stabilize the structure until it can be replaced. These inspection, repair, and replacement programs reduce the likelihood of a risk event involving underground structures.

SCE began including structures without equipment in the UDI program in 2010, going from inspecting a few structures to over 8,000 structures in 2011, and approximately 20,000 structures in 2012. SCE is forecasting a total of 159,133 inspections in 2014 and 172,819 inspections in 2015.

Other Electrical Equipment Failure

SCE defines infrastructure[22] as "major pieces of equipment, such as poles, transformers, switches, circuit breakers, capacitors, automatic re-closers, cable, and conductors that make up the distribution and substation system." All infrastructure will

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[21] Discussed in more detail in SCE-03, Volume 7, page 26.

[22] SCE-03, Vol. 4, pages 1-3.

need to be replaced at some point, but the pacing and prioritization of that replacement can vary depending on the system and use. In general, programs associated with the replacement of equipment as a result of inspections are described under Preventive Capital Maintenance. Programs associated with replacement of equipment after their in service failure are described under Breakdown Capital Maintenance. SCE contends that "programs associated with equipment replacement using a risk/reliability-based approach are described here under Infrastructure Replacement." SCE focuses its Infrastructure Replacement program in three areas:

- Distribution equipment;
- Substation equipment; and
- 4 kV circuits and substations.

SCE states that there are various options when it comes to replacing equipment as it wears out, including:

- Run-to-failure, i.e., wait until the equipment fails in service and then replace it;
- Inspection-driven replacement, i.e., replace the component prior to in-service failure after inspections identify observable indications of imminent failure;
- Risk/reliability-based preemptive replacement, i.e., replace the component prior to in-service failure when engineering analyses predict excessive risk.

With these concepts in mind, we now turn to SCE programs and sources of data and information used to evaluate the risk of other electric equipment failure.

SCE emphasizes equipment age as the basis for its risk/reliability program. SCE utilizes this metric more than other predictive maintenance and inspections by placing inspection-driven replacement in a different category. However, risk assessment is not a function of age only. Although categorizing equipment replacements in this way may be advantageous for accounting or rate case purposes, equipment in high risk categories should be analyzed using predictive inspections and maintenance results, as well as age. Inspection results are very useful in determining equipment health and shutting down equipment when failure is imminent. Thermography is very useful in finding overheated or failing equipment and loose connections on equipment. Oil sampling and oil level monitoring are useful in identifying transformer problems and impending failures. Another example is the Online Transformer Monitoring Program. According to SCE[23], this program will improve SCE's ability to detect impending transformer failures in a timely manner. There have been catastrophic failures of relatively new transformers for a variety of reasons, such as oil leaks from bushings or construction defects. These defects are not related to the age of the equipment, and should be considered to be 'high risk' – predictive maintenance provides the necessary data to make the risk determination. Equipment that is categorized as 'high risk' (either because of either probability of failure or impact of failure) should receive closer scrutiny using inspections and preventive maintenance.

SED staff is aware that SCE does have an inspection and predictive maintenance program. However, SCE has not provided sufficient documentation to fully inform the new requests made for its Infrastructure Replacement program. SED staff encourages SCE to integrate data from inspection and maintenance programs into its risk assessment and management process going forward. Regarding the analysis of aging equipment, SCE appears to have extensive data and analysis as discussed below.

SCE's states[24] that its "Asset Management and System Reliability group (AMSR) is responsible for establishing a long-term strategy for managing distribution system reliability through asset management." SCE continues to state that AMSR maintains "records of distribution assets, tracks distribution system and circuit reliability, identifies actual and probable performance trends… on major substation equipment,

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[23] SCE-03, Volume 8.

[24] SCE-03, Volume 4.

analyzes historic performance, assesses risks of future in-service failures, and develops long-term infrastructure replacement strategies."

Using age, failure and performance data of the AMSR group, SCE has created Weibull curves for its major equipment. A Weibull curve plots the rate of failure vs. age. Using Weibull curves, SCE can predict when the failure rate of equipment begins to climb at a rate which will have a significant negative effect on reliability or safety. Using the output from the Weibull curves, SCE develops a replacement rate schedule, with the intention of keeping the reliability of its infrastructure at an acceptable level.

Transformers are an example of this process. SED staff highlights this example because failure can have both a negative impact on reliability and also a significant safety concern, since failure can result in explosion and fire. After determining the average number of B-Bank transformers needing replacement, SCE develops a prioritization by creating a "health index" (which is effectively the inverse of its probability of failure).[25] This is a function of a transformer's age, loading, fault counts, maintenance orders, oil quality, oil dissolved gas analysis results, and manufacturer. SCE continues to evaluate each transformer for its "criticality" or consequences that would result from an in-service failure. The primary indicator of a transformer's urgency for replacement is its Risk Ratio, which is the product of its Health Index and its Criticality. From this algorithm-derived replacement prioritization, a five-year replacement schedule is drafted. Two adjustments are made to this draft schedule. The first is made by a team of technical experts (managers and supervisors responsible for maintaining these transformers) to ensure that factors difficult to quantify are incorporated into the prioritization process such that high-risk transformers are not overlooked. A second adjustment to the schedule is made to optimize the construction

[25] SCE-03, Volume 4, page 81.

aspects of the replacements. SCE's transformer replacement could serve as an example for other programs, since it takes a risk based approach, which utilizes a variety of data, and takes advantage of informed judgment to conduct the replacements.

Physical and Cyber Security

Physical and cyber security risk drivers can broadly be classified as 1) actual risk and 2) regulatory compliance risk from new standards and regulations.

SCE lists[26] the potential impact of the actual risks as[27]:

1) Outages, potentially widespread outages
2) Loss or damage to equipment
3) Injury to workers or public
4) Release of confidential information

SCE lists the drivers of physical and cyber security risk as evolving security threats. SCE proposes increasing automation and expansion of information systems, and replacing aging or obsolete security equipment. SED staff observes that an emerging physical risk was identified by the April 16, 2013 security incident at the Metcalf Substation. SED staff notes that a GRC filing is a forecast based on a snapshot in time, events such as the attack on the Metcalf substation, may shift priorities after the filing application has occurred. With respect to cyber threats, SCE identifies a significant increase in attempts at intrusion into its cyber systems.[28] In addition to operational threats, these cyber-attacks may put sensitive customer information at risk. With respect to physical risk, in addition to growing concern over threats from terrorist agents, SCE continues to face the normal threats from vandals and copper thieves. These threats

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[26] SCE-15, pages 56-57.

[27] SCE gives examples and incidences of each of these types of risk in SCE-07 Volume 4. SCE discusses evolving cyber security risks in SCE-05, Volume 1.

[28] SCE-01 and SCE-05, Volume 2, Part 1.

present an ongoing financial liability to SCE and a potential safety risk for the vandals. The assessment and management of terrorist risks are informed by the Department of Homeland Security.

With regard to regulatory compliance risk, new regulations compel SCE to improve both its physical and cyber security protections. SCE faces new or expanded National Electric Regulatory Corporation (NERC) standards along with potential new regulations at a state level[29]. NERC CIP v5 expands a collection of standards focused around cyber security, physical protection of cyber assets, training, information protection and access control. SCE has also begun preparations for the proposed CIP 14 on Physical Security, which is currently before the Federal Energy Regulatory Commission (FERC). CIP 14 will require enhanced physical security measures, in particular perimeter defense, at selected facilities. SCE anticipates an increase of Physical Security Perimeters which will require enhanced measures under these regulations.

SCE identifies four major areas for risk mitigation in this category:

1. Facility Access and Monitoring
2. Physical Perimeter Defense
3. Pre-employment background investigations
4. Cyber systems

SCE identifies fourteen activities to mitigate cyber and physical security threats[30]. These include both capital and operations and maintenance (O&M) expenses. SED staff anticipates that each of the physical and cyber security mitigation activities will continue to be a high priority.

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[29] SED Staff notes that there is pending state legislation, Senate Bill 699 (Hill), on this topic. SED staff does not explicitly consider it at this point since it has not yet passed the legislature.

[30] SCE -15, Table III-7, 6a to 6n.

SCE requests enhancements for its corporate security department and security officers (O&M) and NERC/CIP Physical Security (capital). Both of these expenses relate to physical perimeter defense; in part, these requests are required by new regulation. SCE has chosen to greatly increase its security force and to add "enhanced" security guards, with greater and more specialized training.[31] SED staff notes that these security guards will be deployed not only at substations, but at all types of corporate facilities. SCE investigated other alternatives and combinations of protective measures, settling on this solution. The NERC/CIP Physical Security capital costs are driven specifically by the new NERC regulations. These expenses appear to include advanced technology, including a Physical Security Information Management (PSIM) tool, which integrates alarm information and is tied into the new Edison Security Operations Center (ESOC)[32]. It is not clear how PSIM and ESOC requests align with other protections. SCE indicates that use of the technological solution could save on additional expenses for more security guards, but it's not clear what optimal set of solutions will ensure adequate mitigation of security risks.[33] SED staff notes that the NERC/CIP requirements only extend to the bulk power systems, and SCE needs to address related security concerns onto the other parts of its system. SED staff encourages that SCE employ a holistic approach when it comes to physical security requirements.

SCE does not request funding for Workplace Security and Grid Protection, CCURE Upgrade, and Master Access Project. For NERC Compliance O&M, SCE indicates that it is necessary for operational expenses involved in the compliance with new NERC regulations. SCE requests a new security operations center to replace its

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[31] SCE -15, page 61.

[32] SCE-07, Volume 4, page 41-42.

[33] SCE-07, Volume 4, page 41.

Central Alarm station, which SCE states is outdated and undersized[34]. SCE also requests funding to implement various technology enhancements in the area of cybersecurity and customer data protection. These areas and the mitigation solutions chosen seem appropriate given evolving cyber threats and regulation.

SCE requests funding for additional special physical security projects. For example, the A-Bank Substation perimeter project adds enhanced monitoring and deterrence efforts to perimeters of some critical, unstaffed 220 KV substations. Included in this projects are advanced intrusion detection, cameras, etc.[35] These areas will provide similar enhanced protection to these facilities that would not necessarily be covered under new NERC regulations on physical security.

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[34] SCE-15, page 60.

[35] SCE-15, page 63.

RECOMMENDATIONS

Based on the observations made throughout this report, SED staff offers the following recommendations, for either this GRC Application or for future GRCs, as appropriate.

1. SCE should continue on the path of injecting quantitative rigor into its risk evaluation process by improving data collection to enhance knowledge on failure likelihoods. SCE should employ existing data sets and workflows as much as possible into this process.
2. SCE should improve its risk ranking process to demonstrate the incremental value of risk control measures at different scopes and paces of implementation.
3. SCE should provide additional analysis of the alternatives that were considered but ultimately rejected to support its selection of the proposed mitigation. This information will provide additional insights into SCE's risk tolerance and put the mitigation request into the context.
4. SCE should explore the concept of As Low As Reasonably Practicable (ALARP) as part of its risk tolerance in the consideration of its next General Rate Case Application. SCE should balance this approach with prudent application of industry best practices.
5. SCE should consider interactive threats and interactive mitigations of those threats in a more quantitatively rigorous manner. This should complement, not replace, the current qualitative approach, which relies primarily on the informed judgment of its subject matter experts.
6. SCE should strongly consider using a risk-based approach that aligns with the 10 criteria of a risk informed rate case, developed by the Cycla Corp. identified in this report for the preparation of its next General Rate Case.

7. SCE should report progress on mitigation of identified threats and risks to SED staff, including emerging priorities which may shift funding away from approved projects.

CONCLUSION AND NEXT STEPS

In this report, SED staff provides a review of the top risks identified in SCE's supplemental testimony in its GRC. When possible and appropriate, SED staff provided insights and analysis to the nature of the risks identified, the mitigation of risks that could occur with the proposed project, and the alternatives SCE considered. SED staff also shared some general insights and observations about SCE's risk methodology employed in its GRC Application, the identification of threats, the assessment of risks and the mitigation. SED staff also observed impacts these risks had on reliability and resiliency of SCE's system.

The SED staff report provides technical insights and analysis on five of the ten top risks identified by SCE, thematically concentrating on the transmission and distribution aspects of its system. The report focused on the risks of these hazards: conductor failure, pole failure, underground structure failure, other electric equipment failure and physical & cyber security. For each risk, SED staff identifies the data and information available to make an informed risk assessment.

As a next step, SED staff anticipates that the assigned Administrative Law Judges may host a workshop on this SED staff report. The workshop will focus on a discussion of the SED staff report, including technical questions, corrections and clarifications. We anticipate that further information about the workshop, including location and timing, will be disseminated to the service list. After the workshop, the Administrative Law Judges will give further direction to SED staff, including any revisions to the report and how the report will be introduced into the record of A.13-11-003.