Risk Assessment Mitigation Phase

Risk Mitigation Plan

Major Disturbance to Electrical Service (e.g., Blackout)

(Chapter SDG&E-5)

November 30, 2016

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Executive Summary

Major Disturbance to Electrical Service is the risk of a blackout or major loss of electric service throughout the SDG&E service territory. The loss of the electric power could occur in a large area, or across the entirety of the SDG&E service territory. The impact of a blackout can vary significantly depending on its extent and duration. SDG&E's 2015 baseline mitigation plan for this risk consists of two controls:

1. Advance Readiness
2. Monitoring and Control of the Bulk Electric System (BES)

These controls focus on safety-related impacts (i.e., Health, Safety, and Environment) per guidance provided by the Commission in Decision 16-08-018 as well as controls and mitigations that may address reliability. The 2015 baseline mitigation activities will continue to be performed in the proposed plan to, in most cases, maintain the current residual risk level. In addition, SDG&E's proposed risk mitigation plan includes the addition of new facilities and the implementation of new tools to further reduce human errors.

A risk spend efficiency was developed for Blackout. The risk spend efficiency is a new tool that was developed to attempt to quantify how the proposed mitigations will incrementally reduce risk. The data used to determine the risk spend efficiency of the mitigations was based on industry research, information from adjacent utilities and inter-utility studies. The following is the ranking of the mitigation groupings from the highest to the lowest efficiency, as indicated by the RSE number:

1. Monitoring and Control (current controls)
2. Advanced Readiness (current controls)
3. Ongoing Transmission Projects and Planning (current controls)
4. Modernization of Grid Control Centers (incremental mitigations)

Risk: Major Disturbance to Electrical Service (e.g., Blackout)

1 Purpose

The purpose of this chapter is to describe the mitigation plan of San Diego Gas & Electric Company (SDG&E or Company) for the risk of Major Disturbance to Electrical Service. This is the risk of a blackout or major loss of electric service throughout the SDG&E service territory. The loss of the electric power could occur in a large area, or across the entirety of the SDG&E service territory. The impact of a blackout can vary significantly depending on its extent and duration. For example, the loss of the entire SDG&E system would have a greater impact than the loss of multiple power substations.

The risk addressed in this chapter deals with blackouts caused at the transmission-level, not at the distribution level. The Federal Energy Regulatory Commission (FERC) regulates Transmission, and so mitigation and costs are generally matters within FERC's oversight and authority.

Blackouts can be caused in various ways, including, but not exclusive to human errors, natural disasters, or asset failures. They can negatively impact critical sites where the environment and public safety can be at risk and have significant financial consequences. Even though electric power systems are planned and operated in accordance with established, strict reliability standards, unexpected events that fall outside these planning standards, make it difficult to fully eliminate the risk exposure of a blackout.

The risk assessment provided herein focuses on the factors or drivers and potential consequences for which SDG&E is aware. The mitigation activities and risk scores presented in this chapter captures what was known in 2015, which is the baseline year for the risk assessment. These activities help mitigate the blackout risk, but may not be solely performed for that purpose SDG&E has included FERC jurisdictional mitigations to demonstrate the completeness of its mitigation plan. However, these costs are for demonstration in the Risk Assessment Mitigation Phase (RAMP) only and will not be addressed or requested in the Test Year 2019 General Rate Case (GRC).

Mitigations related to the maintenance of existing electric transmission infrastructures, physical security, and cyber security, important for preventing a blackout, are covered in the RAMP risk chapters of: Electric Infrastructure Integrity, Public Safety Events – Electric and Cyber Security, respectively. Mitigations considered in this chapter improve and maintain safety by reducing the occurrence of system wide blackouts.

This risk is a product of SDG&E's September 2015 annual risk registry assessment cycle. Any events that occurred after that time were not considered in determining the 2015 risk assessment, in preparation for this Report. Note that while 2015 is used a base year for mitigation planning, risk management has been occurring, successfully, for many years within the Company. SDG&E and Southern California Gas Company (SoCalGas) (collectively, the utilities) take compliance and managing risks seriously, as can be seen by the number of actions taken to mitigate each risk. This is the first time, however, that the utilities have presented a RAMP Report, so it is important to consider the data presented in this plan in that context. The baseline mitigations are determined based on the relative expenditures during 2015;

however, the utilities do not currently track expenditures in this way, so the baseline amounts are the best effort of each utility to benchmark both capital and operations and maintenance (O&M) costs during that year. The level of precision in process and outcomes is expected to evolve through work with the California Public Utilities Commission (Commission or CPUC) and other stakeholders over the next several GRC cycles.

The Commission has ordered that RAMP be focused on safety related risks and mitigating those risks.[1] In many risks, safety and reliability are inherently related and cannot be separated, and the mitigations reflect that fact. Compliance with laws and regulations is also inherently tied to safety and the utilities take those activities very seriously. In all cases, the 2015 baseline mitigations include activities and amounts necessary to comply with the laws in place at that time. Laws rapidly evolve, however, so the RAMP baseline has not taken into account any new laws that have been passed since September 2015. Some proposed mitigations, however, do take into account those new laws.

The purpose of RAMP is not to request funding. Any funding requests will be made in the GRC. The forecasts for mitigation are not for funding purposes, but are rather to provide a range for the future GRC filing. This range will be refined with supporting testimony in the GRC. Although some risks have overlapping costs, the utilities have made efforts to identify those costs.

2 Background

Mitigation activities to maintain system reliability and prevent the occurrence of blackouts are of paramount importance to SDG&E and society. Although the likelihood of a wide-spread, noteworthy blackout is small, there have been significant blackouts occurred throughout North America, Europe and other locations in recent history. For instance, the Northeast Blackout that occurred on August 14, 2003, impacted large portions of the Midwest and Northeast United States and Ontario, Canada. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey, and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and, in some parts of the United States, power was not restored for four days. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion (U.S. dollars). In Canada, gross domestic product was down 0.7% in August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).[2]

[1] Commission Decision (D.) 14-12-025 at p. 31.
[2] U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", April 2004 http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/ch1-3.pdf.

3 Risk Information

As stated in the testimony of Jorge M. DaSilva in the Safety Model Assessment Proceeding (S-MAP) Application (A.) 15-05-002, "SDG&E is moving towards a more structured approach to classifying risks and mitigations through the development of its new risk taxonomy. The purpose of the risk taxonomy is to define a rational, logical and common framework that can be used to understand analyze and categorize risks."[3] The Enterprise Risk Management (ERM) process and lexicon that SDG&E has put in place was built on the internationally-accepted IS0 31000 risk management standard. In the application and evolution of this process, the Company is committed to increasing the use of quantification within its evaluation and prioritization of risks.[4] This includes identifying leading indicators of risk. Sections 3 – 9 of this plan describe the key outputs of the ERM process and resultant risk mitigations.

In accordance with the ERM process, this section describes the risk classification, possible drivers and potential consequences of the Blackout risk.

3.1 Risk Classification

Consistent with the taxonomy presented by SDG&E and SoCalGas in A.15-05-002, SDG&E classifies this risk as an electric, operational risk associated with generation and transmission as shown in Table 1.

Table 1: Risk Classification per Taxonomy

Risk Type	Asset/Function Category	Asset/Function Type
OPERATIONAL	ELECTRIC	GENERATION AND TRANSMISSION

3.2 Potential Drivers[5]

When performing the risk assessment for Major Disturbance to Electric Services, SDG&E identified potential indicators of risk, referred to as drivers. The drivers identified were determined using historical data of blackouts in North America. These include, but are not limited to:

- **Generation Resource Constraints -** Electrical power systems rely on a continuous balance between load and generation to remain stable. Generation deficiencies related to energy market issues, lack of gas supply, lack of reserves, and lack of inertia or poor load forecast can lead to instability.

- **Grid Reliability Events -** Events, such as protection system mis-operations, can either initiate or increase the severity of an electrical disturbance.

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[3] A.15-05-002, filed May 1, 2015, at p. JMD-7.
[4] Testimony of Diana Day, Risk Management and Policy (SDG&E-02), submitted on November 14, 2014 in A.14-11-003.
[5] An indication that a risk could occur. It does not reflect actual or threatened conditions.

- **Loss of Key Transmission Assets -** Forced or unplanned outages of major transmission lines (above 100 kV), if not studied properly or monitored, can lead to cascading, uncontrolled separation, or instability.

- **Software Bug in the Energy Management System -** A malfunction of the energy management system can prevent operators from responding to a disturbance.

- **Human Error -** Unintentional faults due to human operational oversight.

- **Natural Causes -** Unforeseen extreme natural events (i.e., lightning, wide area wildfires, or earthquake) can trigger the loss of several key transmission and generation assets that could lead to a blackout.

Table 2 maps the specific drivers of Major Disturbance to Electric Services to SDG&E's risk taxonomy.

Table 2: Operational Risk Drivers

Driver Category	Major Disturbance to Electric Services (e.g., Blackout) Driver(s)
Asset Failure	• Generation resource constraints • Grid reliability events • Loss of key transmission assets
Asset-Related Information Technology Failure	• Software bug in the energy management system
Employee Incident	• Human error
Contractor Incident	Not applicable
Public Incident	Not applicable
Force of Nature	• Natural causes (e.g. earthquakes, wildfires)

3.3 Potential Consequences

If one of the risk drivers listed above were to occur, resulting in an incident, the potential consequences, in a reasonable worst case scenario, could include:

- Health and safety impacts, including life threatening injuries, to SDG&E customers and the public;
- Operational and reliability impacts;
- Exposure to compliance violations and penalties;
- Adverse litigation;

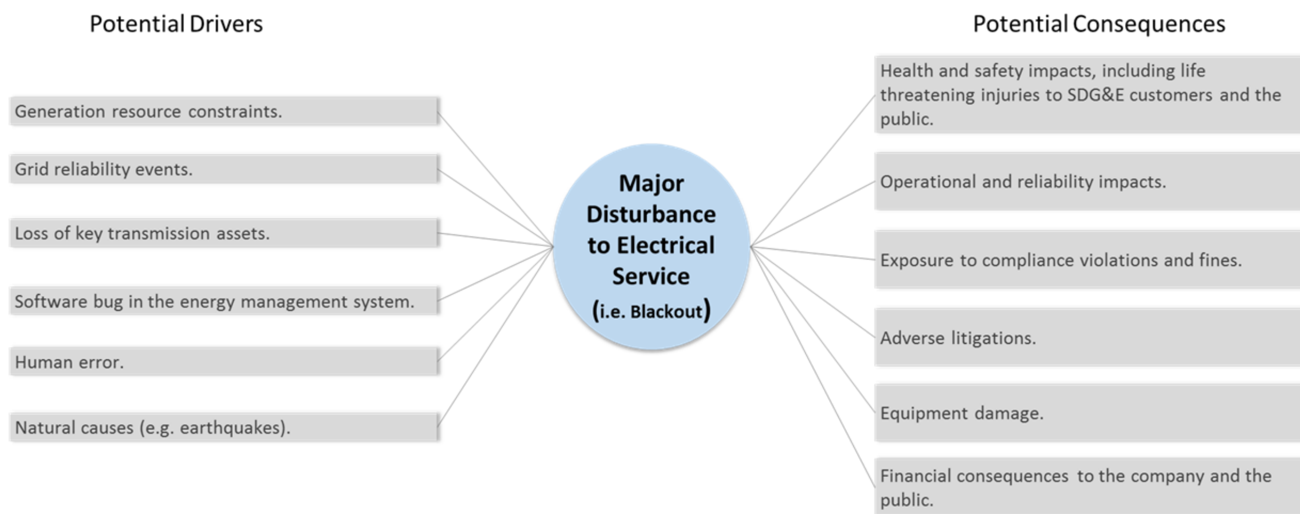
- Equipment damage; and/or
- Financial consequences to the Company and the public.

These potential consequences were used in the scoring of Major Disturbance to Electric Services that occurred during the SDG&E's 2015 risk registry process. See Section 4 for more detail.

3.4 Risk Bow Tie

The risk "bow tie," shown in Figure 1 is a commonly-used tool for risk analysis. The left side of the bow tie illustrates potential drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above.

Figure 1: Risk Bow Tie



4 Risk Score

The SDG&E and SoCalGas ERM organization facilitated the 2015 risk registry process, which resulted in the inclusion of Blackout as one of the enterprise risks. During the development of the risk register, subject matter experts assigned a score to this risk, based on empirical data to the extent it is available and/or using their expertise, following the process outlined in this section.

4.1 Risk Scenario – Reasonable Worst Case

There are many possible ways in which a blackout can occur. For purposes of scoring this risk, subject matter experts used a reasonable worst case scenario to assess the impact and frequency. The scenario represented a situation that could happen, within a reasonable timeframe, and lead to a relatively significant adverse outcome. These types of scenarios are sometimes referred to as low frequency, high consequence events. The subject matter experts selected a reasonable worst case scenario to develop a risk score for Major Disturbance to Electric Services (e.g., Blackout):

- The loss of multiple transmission assets due to a significant event. Potential consequences include life threatening injuries or few fatalities. The operational impacts affect critical customers and entire metropolitan areas leading to severe and long-term consequences to the environment. Blackouts may involve regulatory compliance violations, litigation, and financial consequences. Specifically, a system-wide blackout, similar to the September 8, 2011, Pacific Southwest Blackout that affected the entire SDG&E system, was used as a baseline to score this risk.[6]

Note that the following narrative and scores are based on this scenario; they do not address all consequences that can happen if the risk occurs.

4.2 2015 Risk Assessment

Using this scenario, subject matter experts then evaluated the frequency of occurrence and potential impact of the risk using SDG&E's 7X7 Risk Evaluation Framework (REF). The framework (also called a matrix) includes criteria to assess levels of impact ranging from Insignificant to Catastrophic and levels of frequency ranging from Remote to Common. The 7X7 framework includes one or more criteria to distinguish one level from another. The Commission adopted the REF as a valid method to assess risks for purposes of this RAMP.[7] Using the levels defined in the REF, the subject matter experts applied empirical data to the extent it is available and/or their expertise to determine a score for each of four residual impact areas and the frequency of occurrence of the risk.

Table 3 provides a summary of the Blackout risk score in 2015. This risk has a score of 4 or above in the Health, Safety, and Environmental impact area and, therefore, was included in the RAMP. These are residual scores because they reflect the risk remaining after existing controls are in place. For additional information regarding the REF, please refer to the RAMP Risk Management Framework chapter within this Report.

Table 3: Risk Score

Residual Impact				Residual Frequency	Residual Risk Score
Health, Safety, Environmental (40%)	Operational & Reliability (20%)	Regulatory, Legal, Compliance (20%)	Financial (20%)		
6	7	5	5	2	44,458

4.3 Explanation of Health, Safety, and Environmental Impact Score

SDG&E scored this risk a 6 (severe) in the Health, Safety, and Environmental impact area due to its potential to result in life-threatening injuries or fatalities to employees or the public. For example,

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[6] The 2011 Pacific Southwest Blackout occurred on September 8, 2011, when an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving approximately 2.7 million customers without power.
[7] D.16-08-018 Ordering Paragraph 9.

during the Northeast Blackout of August 2003, New York City officials reported a spike in emergency room treatments for diarrheal illnesses, presumably caused by eating spoiled food.[8] Fires caused by burning candles were reported across the city. Some of the deaths reported that day were attributed to carbon monoxide poisoning caused by fires or malfunction of home generators. Similar deaths were also reported during the 2012 Superstorm Sandy that caused significant power outages in the New Jersey area.[9] New research suggests that more deaths and injuries can be attributed to a blackout if accidents, cardiovascular conditions, respiratory problems, home medical device failures, and various other health conditions are considered.[10]

This is especially true given the loss of traffic signals which increases the likelihood of vehicle accidents. Also, critical facilities, such as hospitals with inadequate backup generators, run the risk of not to being able to care for patients.

With respect to environmental impacts, the Pacific Southwest outage resulted in some sewage pumping station failures that resulted in contaminated beaches and potentially unsafe water supplies in several areas.

4.4 Explanation of Other Impact Scores

Based on the selected reasonable worst case risk scenario, the following scores were assigned to the remaining residual risk categories.

- **Operational and Reliability:** A score of 7 (catastrophic) was given to this risk as a system-wide blackout, could affect the 3.6 million customers of SDG&E.
- **Regulatory, Legal, Compliance:** A score of 5 (extensive) was given as there are instances where blackout causes can be traced back to weak implementations of some of the North American Electric Reliability Corporation (NERC) standards by a Utility company, an Independent System Operator, or a Reliability Coordinator. During the Pacific Southwest Blackout, it was found that some of the entities involved violated one or more reliability standards. The alleged compliance violations resulted in penalties.[11]
- **Financial:** Financial consequences to the Company and the public may also result from a blackout. Blackouts may cause significant losses to local businesses (e.g., restaurants, grocery

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[8] Shao Lin, Barbara A. Fletcher, Ming Luo, et al. "Health Impact in New York City During the Northeastern Blackout of 2003", Public Health Reports, 2011 May-Jun, http://www.publichealthreports.org/issueopen.cfm?articleID=2629.

[9] Centers for Disease Control and Prevention, "Deaths Associated with Hurricane Sandy – October –November 2012", https://www.cdc.gov/mmwr/preview/mmwrhtml/mm6220a1.htm..

[10] G. Brooke Anderson and Michelle L. Bell, "Lights out: Impact of the August 2003 power outage on mortality in New York", Public Health Reports, Epidemiology. 2012 Mar; http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3276729/#R25.

[11] Federal Energy Regulatory Commission, "FERC Approves Final Settlement in 2011 Southwest Blackout Case", May 26,2015, Docket No IN14-11-000, http://www.ferc.gov/media/news-releases/2015/2015-2/05-26-15.asp#.V5aaIPkrJhE.

stores) and households. The business continuity of manufacturing plants and commercial businesses also may be impacted. Furthermore, blackouts can cause data loss and damage to assets such as computers and plant equipment. Lastly, possible lawsuits by individuals or businesses, coupled with regulatory penalties not covered under insurance policies, also can have financial impacts.[12] Subject matter experts considered this information when assigning a scoring of 5 (extensive) to this impact.

4.5 Explanation of Frequency Score

The 2011 Pacific Southwest Blackout is the only major system-wide blackout SDG&E has experienced since its creation. Other utilities in California have also had infrequent blackouts compared to utilities located in the northeastern and southeastern part of the United States. This can be explained in large part, by weather patterns in the eastern part of the United States (i.e., harsh winter and tropical storms). Accordingly, a low frequency of occurrence was selected because SDG&E has had only one major system-wide blackout. This corresponds to a score of 2 (rare), defined by the 7X7 matrix as an event that occurs once every 30-100 years.

The likelihood of a blackout in the SDG&E territory potentially could increase if major earthquakes or wild fires were to happen more often in San Diego County. Also, Blackouts may be driven by external entities. SDG&E's system depends on operational decisions made by the California Independent System Operator (CAISO), the Reliability Coordinator (Peak RC), and Western Electricity Coordinating Council (WECC), along with operational actions by neighboring utilities. A poor operational decision by an external entity can affect SDG&E's ability to serve its customers.

5 Baseline Risk Mitigation Plan[13]

As stated above, SDG&E defines Major Disturbance to Electrical Service risk as a blackout or major loss of electric service throughout the SDG&E service territory. The 2015 baseline mitigations discussed below include the current evolution of the utilities' risk management of this risk. The baseline mitigations have been developed over many years to address this risk. They include the amount to comply with laws that were in effect at that time.

SDG&E's 2015 risk mitigation plan includes a mix of two controls: (1) Advance readiness, and (2) Monitoring and Control of the Bulk Electric System (BES). Activities include: 24-hour real-time monitoring and control of all transmission assets; the development of short-term operating plans to prepare for potential system disturbances; seasonal studies; procedure coordination; personnel training; event reporting; and regulatory audits. These controls focus on safety-related impacts[14] (i.e., Health,

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[12] E. Mills and R. Jones, "An Insurance Perspective on U.S. Electric Grid Disruption Costs", Electricity Markets and Policy Group, Geneva Papers on Risk and Insurance Issues and Practice, Feb 2016; https://emp.lbl.gov/sites/all/files/lbnl-1004466.pdf.

[13] As of 2015, which is the base year for purposes of this Report.

[14] The Baseline and Proposed Risk Mitigation Plans may include mandated, compliance-driven mitigations.

Safety, and Environment) per guidance provided by the Commission in D.16-08-018[15] as well as controls and mitigations that may address reliability.[16] Accordingly, the controls and mitigations described in Sections 5 and 6 address safety-related impacts primarily. Note that the controls and mitigations in the baseline and proposed plans are intended to address various types of blackouts, not just the scenario used for purposes of risk scoring.

1. Advance Readiness

Advance readiness is of great importance in the avoidance of blackouts. It includes seasonal system impact studies of major known outage events, coordination of transmission protection schemes with neighboring utilities, and annual updates to the under-frequency load shedding program within the Western Electricity Coordinating Council (WECC) requirements. Participation in inter-utility regional studies and reliability standard development enables engineers to continuously share knowledge they acquire while operating their own system. Studies involve power flow, transient stability, post transient voltage stability, and other analyses. This knowledge is then used to establish parameters, guidelines, and standards that help maintain the reliability of the electric grid.

2. Monitoring and Control of the Bulk Electric System (BES)

The reliability of the SDG&E system depends on its continuous internal network connectivity and connectivity with its neighboring utilities. Events that unravel Interconnections, such as those in the August 2003 Northeast Blackout, may start out slowly, and then escalate to very fast (fractions of a second) cascading failures that cannot be manually stopped once they enter their dynamic phase.[17] While SDG&E cannot prevent events from happening on its system, it can monitor the Bulk Electric System (BES) and alert the CAISO to pending issues.

Real-time operation comprises all activities associated with the support and implementation of real-time actions to maintain the safe and reliable operation of the SDG&E electrical transmission grid and interconnections to prevent system collapse, separation, and overloads that might damage equipment and jeopardize the safety of personnel and the public. This activity provides the main point of contact with neighboring utilities, the California Independent System Operator (CAISO), and the Reliability Coordinator (Peak RC) and involves Real-time Operators, Outage Coordinators, Trainers, and the Energy Management System (EMS). Real-time operators conduct real-time assessments and establish Operating Limits so that the SDG&E's transmission system is continuously operated within acceptable reliability criteria. They monitor actual power flows on the system, control these flows, and coordinate with the CAISO and Peak RC.

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[15] D.16-08-018 at p. 146 states "Overall, the utility should show how it will use its expertise and budget to improve its safety record" and the goal is to "make California safer by identifying the mitigations that can optimize safety."
[16] Reliability typically has an impact on safety. Accordingly, it is difficult to separate reliability and safety.
[17] North American Electric Reliability Corporation, "Reliability Concepts", Version 1.0.2, December 19, 2007 http://www.nerc.com/files/concepts_v1.0.2.pdf.

The outage coordination group manages and coordinates all transmission equipment outages and switching for scheduled maintenance, construction and modification or testing of all transmission equipment on 69, 138, 230 and 500 kV systems. The training team provides operators with the latest procedures, system changes, industry standards, and tools available.

One of the key findings of the September 8, 2011 Blackout, was that some of the entities' real-time tools were not adequate or operational to alert operators. SDG&E uses an EMS for situational awareness. In addition, the implementation of the Synchrophasor project will help improve real-time measurements needed to increase situational awareness, and aligns with the Company goal to move toward a smarter grid. The project began in 2010 and is expected to be fully implemented by December 2020. It is important to note that this is an evolving technology; the extensive testing, validation and continuous improvement SDG&E plans to do will continue beyond 2020. The Synchrophasor project consists of the installation and maintenance of Phasor Measurement Units (PMU) that take near real-time (sub-second) readings throughout the SDG&E system, and the acquisition of software tools needed for increased situational awareness, enhanced EMS models, Voltage Stability Analysis, Linear State Estimation, Oscillation and Disturbance detection, and to perform post-event analysis. Synchrophasors help provide a better indication of the electric grid stresses and could be used to trigger wide-area corrective actions to maintain grid reliability.

6 Proposed Risk Mitigation Plan

The 2015 baseline mitigation activities outlined in Section 5 will continue to be performed in the proposed plan, in most cases, to maintain the current residual risk level. In addition, SDG&E's proposed risk mitigation plan during the 2017-2019 timeframe includes the addition of new facilities and the implementation of new tools to further reduce human errors. These incremental mitigations are described in detail below.

1. <u>Upgrades and Installation of New Transmission Facilities</u>

SDG&E performs long-term Transmission Planning studies to identify transmission expansion projects to strengthen the electric grid. Those projects aim to upgrade and install additional facilities needed to prevent thermal overloads, transient instability, and voltage stability issues that could lead to a blackout. SDG&E proposed projects include the addition of dynamic reactive resources, new transmission lines, and upgrades to existing substations.

Reactive power resources are important in maintaining healthy power system voltages and facilitating power transfers. According to the U.S. – Canada Power System Task Force of the August 14, 2003, Blackout, inadequate reactive power resources are a common factor in most of the major blackouts that occurred in the past.[18] This means that under certain extreme system conditions, a major disturbance can cause a blackout in the SDG&E system if the amount of dynamic reactive power reserve is not sufficient. The addition of a Static Var Compensator at Suncrest, and the addition of synchronous condensers at San Luis Rey, Miguel, and San Onofre, will provide system operations with dynamic reactive power sources needed to quickly respond to major disturbances.

Another common factor in most of the major blackouts is the inability of a transmission system to maintain its integrity after sudden unexpected transmission line failures force power to flow onto other lines, causing severe thermal overloads. If adjacent transmission lines cannot handle those overloads, it can lead to additional cascading outages that might result in a blackout. Therefore, to have a reliable transmission system, a region requires backup transmission lines with adequate capacity. Furthermore, the rapid increase of renewable generation in the Imperial Valley area, combined with load growth in the SDG&E system, requires upgrades and the construction of new high voltage transmission lines to relieve congested lines which are already close to their maximum capacity. Among the multiple projects proposed to meet reliability standard requirements, SDG&E selected the following transmission capacity projects:

- New Sycamore Canyon to Penasquitos 230 kV transmission line;
- South Orange County Reliability project (Capistrano substation upgrade and addition of 230 kV transmission lines);
- New Imperial Valley flow control device project (Phase Shifting Transformer);
- New second 230 kV transmission line from Miguel to Bay Boulevard; and
- New Mission to Penasquitos 230 kV transmission line.

Those 230 kV projects were determined, based on subject matter experts' experience with the SDG&E system, to have the greatest impact on reducing the likelihood of a major blackout compared to lower voltage projects (below 230 kV) that usually help solve localized reliability issues. This assumption is considered reasonable when observing the type of facility failures that triggered previous major blackouts such as the 1965 Northeast Blackout, the 1977 New York City Blackout, the 1982 and 1996 West Coast Blackouts, the 1998 Upper Midwest Blackout, the 2003 Northeast Blackout, and the 2011 Pacific Southwest Blackout. Although construction associated with those projects is estimated to start during the 2017-2019 period, their in-service dates are estimated to extend to 2021.

[18] U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations", April 2004 http://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/ch1-3.pdf.

2. Modernization of Grid Control Centers

The Transmission Energy Management System Modernization Project will upgrade SDG&E's current mimic board and control room. The upgrades will help improve situational awareness and prevent potential human errors. Upgrades would include replacing the static mosaic tile board with a dynamic video wall, upgrading the peripheral devices/applications that support such systems, and maximizing the utilization of control room space while maintaining an ergonomic work environment consistent with the Company's policies. The result of the Transmission EMS Modernization Project will be enhanced safety and reliability by expediting the identification of critical system conditions through means of dynamic visual content.

3. Advance Readiness

Advanced Readiness is a baseline mitigation that SDG&E is proposing to continue. For a description of this activity, please refer to Section 5 above.

4. Monitoring and Control of the Bulk Electric System

Monitoring and Control of the BES is an ongoing mitigation and is described in detail in Section 5 above.

7 Summary of Mitigations

Table 4 summarizes the 2015 baseline risk mitigation plan, the risk driver(s) a control addresses, and the 2015 baseline costs for Major Disturbance to Electrical Service. While control or mitigation activities may address both risk drivers and consequences, risk drivers link directly to the likelihood that a risk event will occur. Thus, risk drivers are specifically highlighted in the summary tables.

SDG&E does not account for and track costs by activity, but rather, by cost center and capital budget code. So, the costs shown in Table 4 were estimated using assumptions provided by SMEs and available accounting data.

Table 4: Baseline Risk Mitigation Plan[19]
(Direct 2015 $000)[20]

ID	Control	Risk Drivers Addressed	Capital[21]	O&M	Control Total[22]	GRC Total[23]
1	Advance Readiness*	• Generation resource constraints • Loss of key transmission assets • Grid reliability events • Natural causes (e.g. earthquakes, wildfires, etc.)	n/a	$1,030	$1,000	$0
2	Monitoring and Control of the Bulk Electric System*	• Generation resource constraints • Loss of key transmission assets • Natural causes (e.g. earthquakes, wildfires, etc.) • Human error • Public incident (e.g. car contact with poles) • Software bug in the energy management system	4,920	1,580	6,500	0

[19] Recorded costs were rounded to the nearest $10,000.
[20] The figures provided in Tables 4 and 5 are direct charges and do not include Company overhead loaders, with the exception of vacation and sick. The costs are also in 2015 dollars and have not been escalated to 2016 amounts.
[21] Pursuant to D.14-12-025 and D.16-08-018, the Company is providing the "baseline" costs associated with the current controls, which include the 2015 capital amounts. The 2015 mitigation capital amounts are for illustrative purposes only. Because projects generally span several years, considering only one year of capital may not represent the entire mitigation.
[22] The Control Total column includes GRC items as well as any applicable non-GRC jurisdictional items. Non-GRC items may include those addressed in separate regulatory filings or under the jurisdiction of the Federal Energy Regulatory Commission (FERC).
[23] The GRC Total column shows costs typically presented in a GRC.

ID	Control	Risk Drivers Addressed	Capital[21]	O&M	Control Total[22]	GRC Total[23]
	TOTAL COST		$4,920	$2,610	$7,500	$0

***** Includes one or more mandated activities

1. Advance Readiness

Costs for the Advanced Readiness mitigation of $1 million represent the total 2015 annual salaries of the Electric Grid Operations Support cost center. One hundred percent of these costs have been identified as FERC jurisdictional based on the group's labor allocation to Transmission O&M. Therefore, the costs associated with Advance Readiness have been deducted from the GRC Total column of Table 4.

2. Monitoring and Control of the Bulk Electric System

The costs for the Monitoring and Control of the BES mitigation, shown in Table 4, for both Capital and O&M consist of both labor and capital plant expenditures. The labor identified with this activity comprises: 11 Transmission System Operators (TSO), nine Operations Shift Supervisors (OSS), two NERC Certified Trainers, and two NERC Certified Outage Coordinators in the Electric Grid Operations center. Labor costs were estimated by using the average annual salary pay for each job description, multiplied by the number of full-time equivalents (FTEs) and allocating the amounts equally between transmission capital engineering and transmission O&M. The capital costs reflect the 2015 expenditures associated with Synchrophasor installations. Capital costs associated with the EMS are needed in order to be compliant with NERC Critical Infrastructure Protection (CIP) standards. All costs associated with the Monitoring and Control of the BES have are non-GRC (FERC jurisdictional) based on the allocation of labor and identification of capital plant as transmission and have been deducted from the GRC Total amount.

Table 5 summarizes SDG&E's proposed mitigation plan, associated projected ranges of estimated O&M expenses for 2019, and projected ranges of estimated capital costs for the years 2017-2019. It is important to note that SDG&E is identifying potential ranges of costs in this plan, and is not requesting funding approval. SDG&E will request approval of funding, in its next GRC. There are non-CPUC jurisdictional mitigation activities addressed in RAMP; the costs associated with these will not be carried over to the GRC. As set forth in Table 5, the utilities are using a 2019 forecast provided in ranges based on 2015 dollars.

Table 5: Proposed Risk Mitigation Plan[24]
(Direct 2015 $000)

ID	Mitigation	Risk Drivers Addressed	2017-2019 Capital[25]	2019 O&M	Mitigation Total[26]	GRC Total[27]
1	Upgrades and Installation of New Transmission Facilities*	• Generation resource constraints • Loss of key transmission assets • Natural causes (e.g. earthquakes, wildfires, etc.)	$382,560 - 467,570	n/a	$382,560 - 467,570	$0
2	Modernization of Grid Control Centers	• Human error	13,900 - 15,360	n/a	13,900 - 15,360	11,810 - 13,060
3	Advance Readiness*	• Generation resource constraints • Loss of key transmission assets • Grid reliability events • Natural causes (e.g. earthquakes, wildfires, etc.)	n/a	980 - 1,080	980 - 1,080	0
4	Monitoring and Control of the Bulk Electric System*	• Generation resource constraints • Loss of key transmission assets	12,140 - 13,420	1,500 - 1,650	13,640 - 15,070	0

24 Ranges of costs were rounded to the nearest $10,000.
25 The capital presented is the sum of the years 2017, 2018, and 2019 or a three-year total. Years 2017, 2018 and 2019 are the forecast years for SDG&E's Test Year 2019 GRC Application.
26 The Mitigation Total column includes GRC items as well as any applicable non-GRC items.
27 The GRC Total column shows costs typically represented in a GRC.

ID	Mitigation	Risk Drivers Addressed	2017-2019 Capital[25]	2019 O&M	Mitigation Total[26]	GRC Total[27]
		• Natural causes (e.g. earthquakes, wildfires, etc.) • Human error • Public incident (e.g. car contact with poles) • Software bug in the energy management system				
	TOTAL COST		$408,600 - 496,350	$2,480 - 2,730	$411,080 - 499,080	$11,810 - 13,060

	Status quo is maintained
	Expanded or new activity
*	Includes one or more mandated activities

While all the mitigations and costs presented in Table 5 mitigate the Blackout risk, some of the controls also mitigate other risks presented in this RAMP. Specifically, the Modernization of Grid Control Centers mitigation is also included in the Fail to Blackstart risk. Because the Modernization of Grid Control Centers project mitigates the risks of Blackout and Fail to Blackstart, the costs and risk reduction benefits are included in both chapters.

1. Upgrades and Installation of New Transmission Facilities

Preliminary costs shown in Table 5 for the Upgrades and Installation of New Transmission Facilities mitigation consist of both labor and capital plant additions. The labor associated with this activity represents the development of the 10-year transmission plan studies in cooperation with the CAISO. This task is performed by the Transmission Planning group, which attributes 50% of its labor to the development of the 10-year transmission plan studies. The labor costs included above reflect 50% of 2015 labor costs. In other words, for O&M labor expenses, SDG&E used a base year (2015). forecast methodology to project future costs. The dollars associated with addition of capital plant are based on estimated costs provided on accounting documents such as capital budget documents (CBD's) and/or work order forms. While these capital costs were zero-based, they were informed by reviewing previous capital projects and SDG&E experience. The ranges of costs provided for this activity were developed due to uncertainty of the exact capital plant amounts and variability of labor costs.

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2. Modernization of Grid Control Centers

Modernization of Grid Control Center costs reflect estimates developed by the Electric Grid Operations organization for SDG&E's internal capital approval process. The $14 million - $15.4 million includes a portion identified as FERC jurisdictional, non-GRC dollars. $2.1 million - $2.3 million has been identified as non-GRC based on an 85/15 split between CPUC/FERC, respectively, for the Electric Grid Operations departmental accounting allocation.

3. Advanced Readiness

The forecasted range of costs associated with this item is consistent with those recorded in 2015 because, at this time, SDG&E believes the future scope will closely resemble 2015.

4. Monitoring and Control of the Bulk Electric System

Like the Advanced Readiness mitigation, the projected costs for this mitigation are similar to the costs incurred in 2015. The range provided in Table 5 is reasonable as SDG&E anticipates that this activity will not dramatically change in the years 2017-2019.

8 Risk Spend Efficiency

Pursuant to D.16-08-018, the utilities are required in this Report to "explicitly include a calculation of risk reduction and a ranking of mitigations based on risk reduction per dollar spent."[28] For the purposes of this Section, Risk Spend Efficiency (RSE) is a ratio developed to quantify and compare the effectiveness of a mitigation at reducing risk to other mitigations for the same risk. It is synonymous with "risk reduction per dollar spent" required in D.16-08-018. [29]

As discussed in greater detail in the RAMP Approach chapter within this Report, to calculate the RSE the Company first quantified the amount of Risk Reduction attributable to a mitigation, then applied the Risk Reduction to the Mitigation Costs (discussed in Section 7). The Company applied this calculation to each of the mitigations or mitigation groupings, then ranked the proposed mitigations in accordance with the RSE result.

8.1 General Overview of Risk Spend Efficiency Methodology

This subsection describes, in general terms, the methods used to quantify the *Risk Reduction*. The quantification process was intended to accommodate the variety of mitigations and accessibility to applicable data pertinent to calculating risk reductions. Importantly, it should be noted that the analysis described in this chapter uses ranges of estimates of costs, risk scores and RSE. Given the newness of

[28] D.16-08-018 Ordering Paragraph 8.
[29] D.14-12-025 also refers to this as "estimated mitigation costs in relation to risk mitigation benefits."

RAMP and its associated requirements, the level of precision in the numbers and figures cannot and should not be assumed.

8.1.1 Calculating Risk Reduction

The Company's SMEs followed these steps to calculate the Risk Reduction for each mitigation:

1. **Group mitigations for analysis:** The Company "grouped" the proposed mitigations in one of three ways in order to determine the risk reduction: (1) Use the same groupings as shown in the Proposed Risk Mitigation Plan; (2) Group the mitigations by current controls or future mitigations, and similarities in potential drivers, potential consequences, assets, or dependencies (e.g., purchase of software and training on the software); or (3) Analyze the proposed mitigations as one group (i.e., to cover a range of activities associated with the risk).
2. **Identify mitigation groupings as either current controls or incremental mitigations:** The Company identified the groupings by either current controls, which refer to controls that are already in place, or incremental mitigations, which refer to significantly new or expanded mitigations.
3. **Identify a methodology to quantify the impact of each mitigation grouping:** The Company identified the most pertinent methodology to quantify the potential risk reduction resulting from a mitigation grouping's impact by considering a spectrum of data, including empirical data to the extent available, supplemented with the knowledge and experience of subject matter experts. Sources of data included existing Company data and studies, outputs from data modeling, industry studies, and other third-party data and research.
4. **Calculate the risk reduction (change in the risk score):** Using the methodology in Step 3, the Company determined the change in the risk score by using one of the following two approaches to calculate a Potential Risk Score: (1) for current controls, a Potential Risk Score was calculated that represents the increased risk score if the current control was not in place; (2) for incremental mitigations, a Potential Risk Score was calculated that represents the new risk score if the incremental mitigation is put into place. Next, the Company calculated the risk reduction by taking the residual risk score (See Table 3 in this chapter.) and subtracting the Potential Risk Score. For current controls, the analysis assesses how much the risk might increase (i.e., what the potential risk score would be) if that control was removed.[30] For incremental mitigations, the analysis assesses the anticipated reduction of the risk if the new mitigations are implemented. The change in risk score is the risk reduction attributable to each mitigation.

8.1.2 Calculating Risk Spend Efficiency

The Company SMEs then incorporated the mitigation costs from Section 7. They multiplied the risk reduction developed in subsection 8.1.1 by the number of years of risk reduction expected to be realized by the expenditure, and divided it by the total expenditure on the mitigation (capital and O&M). The result is a ratio of risk reduction per dollar, or RSE. This number can be used to measure the relative efficiency of each mitigation to another. Figure 2 shows the RSE calculation.

[30] For purposes of this analysis, the risk event used is the reasonable worst case scenario, described in the Risk Information section of this chapter.

Figure 2: Formula for Calculating RSE

$$Risk\ Spend\ Efficiency = \frac{Risk\ Reduction * Number\ of\ Years\ of\ Expected\ Risk\ Reduction}{Total\ Mitigation\ Cost\ (in\ thousands)}$$

The RSE is presented in this Report as a range, bounded by the low and high cost estimates shown in Table 5 of this chapter. The resulting RSE scores, in units of risk reduction per dollar, can be used to compare mitigations within a risk, as is shown for each risk in this Report.

8.2 Risk Spend Efficiency Applied to This Risk

SDG&E analysts used the general approach discussed in Section 8.1, above, in order to assess the RSE for the Blackout risk. The RAMP Approach chapter in this Report provides a more detailed example of the calculation used by the Company.

The risk assessment team analyzed four mitigation groupings. The first consists of three current operation planning controls; the second is two, ongoing monitoring and control measures; the third is an assortment of ongoing transmission projects; and the fourth is a proposed system modernization project. The analysis of these mitigations used a combination of industry research and risk team estimates, based on SME input.

The mitigations groupings included:

(a) Advance Readiness

- System Impact Studies of Major Outage Events
- Coordination of transmission protection schemes with neighboring utilities - updates to the under-frequency load shedding program within WECC requirements.
- Participate in Inter-Utility Regional Studies and Reliability Councils & Standard Development

(b) Monitoring and Control

- Real-time operation
- Synchrophasor Project

(c) Ongoing Transmission Projects and Planning

- 10-year transmission plan Studies
- San Luis Rey Synchronous Condensers
- San Onofre Synchronous Condenser
- Miguel Synchronous Condensers
- Suncrest Static VAr Compensator
- TL23071: Sycamore Canyon - Penasquitos 230 kV Line
- South Orange County Reliability Project
- Imperial Valley Flow Control Device
- 2nd Miguel to Bay Blvd 230 kV line
- New Mission - Penasquitos 230 kV Line

(d) System modernization (Modernization of Grid Control Centers)

- Transmission Energy Management System Modernization Project

- Current: Advanced Readiness

This mitigation analysis drew on the development of short-term operating plans, coordination with other neighboring utilities, and participation in inter-utility studies. Because the controls in this grouping focus on industry-wide efforts, the team sought to quantify the effectiveness of this mitigation in terms of determining where SDG&E would be positioned in comparison to other utilities if it did not engage in the activities for this mitigation. To do this, the analysis team compiled the electric disturbance event data from the U.S. Energy Information Administration (EIA). The data includes information on incidents by region or state, including the date of the incident, and the number of customers. Because the data was provided by state, states where a utility operates were used as a proxy for the utilities themselves.

Other researchers who have used this data identified a threshold for a blackout to be 50,000 customers.[31,32] The team counted the number of events per state that affected more than 50,000 customers, over 2002-2013 (all years for which data were available) and normalized each state by its population. The results were ordered and sorted into quartiles. SDG&E is a California utility and California ranked near the top of the 2nd quartile, in terms of number of major disturbance events affecting 50,000 customers per state, per population. With input from SMEs, the team determined that if SDG&E were not engaged in this mitigation, it would fall to the bottom of the 2nd quartile, a fall of over 110% from its current position.

Based on this proxy estimate using industry-wide blackout data, the risk team SMEs estimated that if these mitigations were discontinued, the likelihood of an incident would increase by over 110%.

- Current: Monitoring and Control

This risk consists of the maintenance of the energy management system, real time operation, monitoring, and control of the electrical system, as well as the installation of synchrophasors, which provide a better indication of the electric grid stresses and could be used to trigger wide area corrective actions to maintain grid reliability. For the analysis of the effectiveness of this mitigation, the team relied on SME input to estimate the likelihood of a blackout in the absence of these projects. SMEs indicated that without this mitigation, SDG&E could have a blackout once every 1 to 3 years, compared to its current likelihood of once every 30 to 100 years. Determining the risk reduction based on SME input is

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[31] P. Hines, J. Apt, and S. Talukdar. "Trends in the History of Large Blackouts in the United States." IEEE Power and Energy Society General Meeting, 2008.
[32] P. Hines, J. Apt, and S. Talukdar. Large Blackouts in North America: Historical Trends and Policy Implications. Energy Policy, v. 37, pp. 5249-5259, 2009.

SDG&E's best estimate at this time, especially given that there is no industry data available for validation.

- Current: Ongoing Transmission Projects and Planning

This mitigation consists of various transmission planning studies and their associated proposed equipment upgrades and additions. Transmission planning studies ensure projects are proposed to enable the transmission system to withstand the loss of one or two simultaneous transmission facilities. It was assumed that as long as an event/disturbance causes the loss of one or two transmission facilities, a blackout will not occur. Meaning, if three major facilities were lost, the risk of having a blackout increases. Assuming losing three facilities instead of losing two facilities occurs at a 1-10% rate, these efforts reduce the risk by a factor of 10-100. That is, losing two transmission facilities is 10-100 times more likely than losing three transmission facilities. Without these measures, the likelihood score would, conservatively, be 10x its current score.

- Incremental: Modernization of Grid Control Centers

This mitigation upgrades an antiquated EMS visualization tool and control room. This tool will help improve situational awareness and prevent potential human errors. SDG&E estimated that this improvement will reduce the likelihood of a blackout by 10%. SDG&E's SMEs consider this to be the best estimate at this time since there is no industry data available for validation.

8.3 Risk Spend Efficiency Results

Based on the foregoing analysis, SDG&E calculated the RSE ratio for each of the proposed mitigation groupings. Following is the ranking of the mitigation groupings from the highest to the lowest efficiency, as indicated by the RSE number:

5. Monitoring and Control (current controls)
6. Advanced Readiness (current controls)
7. Ongoing Transmission Projects and Planning (current controls)
8. Modernization of Grid Control Centers (incremental mitigations)

Figure 3 displays the range[33] of RSEs for each of the SDG&E Blackout risk mitigation groupings, arrayed in descending order.[34] That is, the more efficient mitigations, in terms of risk reduction per spend, are on the left side of the chart.

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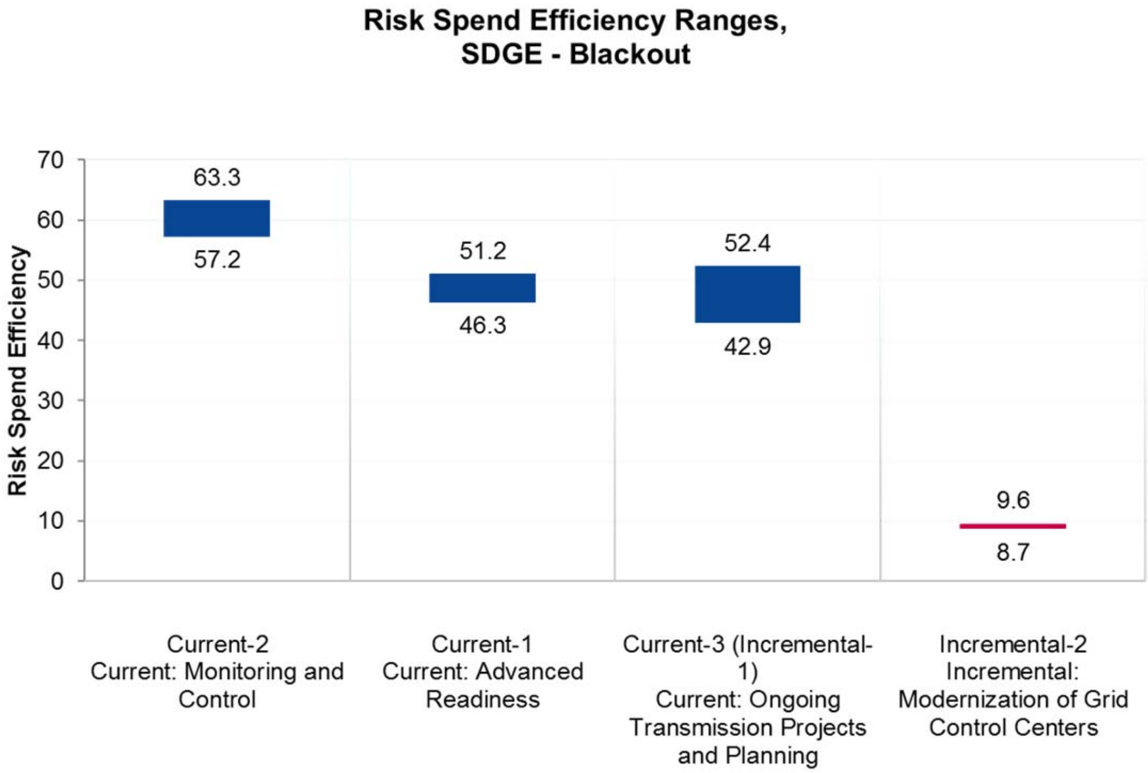
[33] Based on the low and high cost ranges provided in Table 5 of this chapter.
[34] It is important to note that the risk mitigation prioritization shown in this Report, is not comparable across other risks in this Report.

Figure 3: Risk Spend Efficiency



9 Alternatives Analysis

SDG&E considered alternatives to the proposed mitigations as it developed the proposed mitigation plan for the Major Disturbance to Electrical Service (Blackout) risk. Typically, alternatives analysis occurs when implementing activities, and with vendor selection in particular, to obtain the best result or product for the cost. The alternatives analysis for this risk plan also took into account modifications to the proposed plan and constraints, such as budget and resources. Due to the serious safety concerns of a blackout, maintaining the status quo was not considered as a plausible alternative. Instead, adjustment of project scopes and addition of new activities were selected to derive alternatives during the selection process.

9.1 Alternative 1 – Modernization of Grid Control Centers

Modernization of both the primary and back-up control centers was considered as an alternative. Modernization for purposes of this alternative included remodeling of control rooms, installation of Direct View LED video walls, construction of a production development lab, and integration of a new cross-site collaborative software solution. The modernization of the primary Grid Control Center alone was instead selected in SDG&E's proposed plan in anticipation of future plans of an all-encompassing control center, yielding the existing primary Control Center as a sustainable back-up in the future. The existing back-up control center is close to an earthquake fault line, which does not make it an optimal location. The selected alternative project improves public safety by augmenting situational awareness within the control room, which will yield expedient responses to critical system conditions that jeopardize public safety, and by laying the groundwork for a more reliable back-up control center in the future.

9.2 Alternative 2 – Imperial Valley Flow Control Device

The installation of a back-to-back HVDC Converter technology at Imperial Valley was considered as one of the alternatives to control the power flowing from the Imperial Valley substation into Mexico's Centro Nacional de Control de Energia (CENACE) system. The back-to-back HVDC Converter technology was not selected and viewed as infeasible because it was more expensive and required more space at the substation than available. The Phase Shifting Transformer technology was selected instead and proved to have a more adequate cost, footprint, and flow control capability.