Risk Assessment Mitigation Phase

Risk Mitigation Plan

Distributed Energy Resources – Safety and Operational Concerns

(Chapter SDG&E-4)

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Executive Summary

This chapter addresses the risk of safety and reliability events due to the high penetration of distributed energy resources (DERs) on SDG&E's system, which could potentially result in:

1. DERs to be energized and connected to the SDG&E system while SDG&E operators and field personnel have little to no visibility as to the DER's status;

2. SDG&E voltage regulating devices, such as load tap changers (LTCs), line regulators, and capacitors, to operate more frequently than they would on a circuit that is only managing the variations in load, potentially causing:
    a. swings in voltages caused by variable DER output may increase the number of operations of voltage regulating devices; and
    b. impaired outage restoration on circuits with high DER penetrations.
3. Prolonged outage restoration in high penetration areas, due to complications during outages caused by the increased load served by DERs at the point of service. Specifically, outage restoration could be delayed waiting for the projected load to drop low enough for operators to re-energize portions of the circuit.

These safety and operational concerns require a proactive approach to mitigating the impact of DERs to the SDG&E distribution system. SDG&E's 2015 baseline mitigation plan for this risk include a mixture of new tools, outreach, and monitoring, consisting of three controls:

1. **Voltage/Power Quality Studies of DER Interconnections –** Included in the study report will be mitigations that will reduce or eliminate impacts to the distribution system.

2. **Improved Modeling Tools –** SDG&E's improved studies will more accurately capture the impacts of DERs on the system and produce better mitigations than would otherwise be possible.

3. **Interconnection Compliance –** SDG&E's interconnection compliance program provides for UL-certified equipment installed to NEC specifications, marked with signage to inform regarding the electrical hazard.

These baseline mitigations 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 mitigations are being maintained or expanded in the years 2017 through 2019, with the addition of two new mitigations:

1. **Increased Outreach Program**
   The proposed outreach program would add to SDG&E's existing outreach efforts regarding DERs, including any safety issues that may be encountered by the public and first responders.

2. **Anti-Islanding Testing Program**

   The anti-islanding testing program would "test" the anti-islanding function on a routine basis, using the customer's Smart Meter or through a technology solution, to reduce the possibility that a malfunctioning inverter could energize the distribution system during an outage.

The risk spend efficiency was developed for four proposed mitigations of the DER risk. The risk spend efficiency is a new tool that was developed to attempt to quantify how the proposed mitigations will incrementally reduce risk. Based on the risk spend efficiency assessment, the above mitigations for this risk can be prioritized as follows, from highest risk spend efficiency to lowest:

1. Interconnection Compliance
2. Anti-Islanding Testing Program
3. Increased Outreach Program
4. Interconnection Studies and Modeling

Risk: Distributed Energy Resources – Safety and Operational Concerns

1 Purpose

The purpose of this chapter is to present the mitigation plan of San Diego Gas & Electric Company (SDG&E or Company) for the risk of Distributed Energy Resources (DERs). DERs may include Solar Photovoltaic (PV), battery storage devices, electric vehicles, wind turbines, and other small devices that operate in parallel with SDG&E's distribution system.

DERs present two potential risks to SDG&E: safety and operational. The safety risks associated with DERs primarily deal with the potential for DERs to be energized and connected to the SDG&E system while SDG&E operators and field personnel have little to no visibility as to the DER's status. If an SDG&E employee or contractor is working on or near a distribution circuit with DER connected to it, they need to be assured that the DER is not energizing the system after the system is de-energized from the SDG&E substation. This protection is referred to as anti-islanding. The anti-islanding function in a DER inverter (utilized in most DER installations) immediately ceases operation upon the loss of a power signal from SDG&E. It is possible, however, that the anti-islanding protection fails and one or more DER continue energizing the circuit. In this instance, after touching an energized line that was supposed to be de-energized, a serious injury or fatality could occur to a SDG&E employee, contractor, first responder or member of the public.

The operational risk presented by DERs is two-fold. First, swings in voltages caused by variable DER output may increase the number of operations of voltage regulating devices. Second, outage restoration on circuits with high penetrations may be impaired. On a circuit with high DER penetration, the voltage of the circuit may move higher and lower based on the output of the DERs, which can be highly variable, especially solar PV. This can cause SDG&E voltage regulating devices, such as load tap changers (LTCs), line regulators, and capacitors, to operate more frequently than they would on a circuit that is only managing the variations in load. Because of this increased operation frequency, SDG&E would need to maintain these devices more often, and the devices would be more likely to suffer premature failure. In addition, customers who experience high and low voltages due to fluctuating DER may see damage to their appliances.

The other operational concern surrounding high DER penetration is outage restoration. Under a high DER penetration scenario, the DERs will be serving much of the load on a circuit at the point of service. After a forced outage, the inverters for each DER are required by their anti-islanding protection to wait up to 60 seconds before reconnecting to the grid, which causes a temporary increase in load. In this situation, outage restoration will take longer, and in some instances, customers may have to wait up to several hours before the projected load drops low enough for operators to re-energize portions of the circuit. In other words, SDG&E may not have the capacity available to serve load that previously was, in part or entirely, provided by DERs.

These safety and operational concerns require a proactive approach to mitigating the impact of DERs to the SDG&E distribution system. The assessment and analysis presented herein focuses on the risk of DERs owned by third parties who interconnect their system to SDG&E's grid. Those who choose to consume their generation on site and do not choose to interconnect (i.e., are not a SDG&E customer or supplier), are outside the scope of this risk.

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 Risk Assessment Mitigation Phase (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 General Rate Case (GRC) cycles.

The Commission has ordered that RAMP should focus 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

DER interconnections in SDG&E's service territory have increased exponentially over the past several years. SDG&E currently has over 100,000 DER systems connected to its distribution system, compared

[1] Commission Decision (D.) 14-12-025 at p. 31.

with only 11,732 in 2010. SDG&E expects that this number will continue to grow in the coming years, presenting increasing challenges in operating the distribution system safely and reliably.

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."[2] 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.[3] 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 DER 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 as shown in Table 1.

Table 1: Risk Classification per Taxonomy

Risk Type	Asset/Function Category	Asset/Function Type
OPERATIONAL	ELECTRIC	DISTRIBUTION

3.2 Potential Drivers[4]

When performing the risk assessment for DER, SDG&E identified potential indicators of risk, referred to as drivers. These include but are not limited to:

- **Failures of voltage control devices –** Failure of regulating equipment is typically caused by two factors: environment and overuse. DERs do not affect the environmental factors, but variations

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

in voltage will drive up operation count of regulating devices, resulting in wear and tear on their respective mechanisms.

- **Outages on high penetration circuits –** As mentioned above, under a high DER penetration scenario, the DERs will be serving much of the load on a circuit at the point of service. After an outage, the inverters for each DER are required to wait up to 60 seconds before reconnecting to the grid. During this time, SDG&E must serve the additional load on its distribution system, which may not be possible due to limited available capacity. The potential inability to serve additional load is a result of how SDG&E plans for load on its system. SDG&E's distribution planning is done on a net load basis, as opposed to gross load. Net load with respect to DER, Net Energy Metering (NEM) in particular, is the energy produced by the DER minus the energy consumed by the customer. Because the presence of a DER may mask gross load, SDG&E may not know the amount of load present when a DER fails. In this situation, outage restoration will take longer, and in some instances, customers may have to wait up to several hours before the projected load drops low enough for operators to re-energize portions of the circuit.

  Also, during the outages, a DER with failed anti-islanding protection may energize the circuit unbeknownst to utility personnel who may be working on that circuit to restore power to customers on the circuit.

- **Reverse power flow on distribution transformers –** For all DER installations, SDG&E requires each to submit an application and receive a permission to operate (PTO) letter from SDG&E before exporting to the grid. If a DER installer connects their system and exports to the grid without receiving PTO, SDG&E operators may not know that the distribution system is energized by individual DER installations during an outage.

- **Emergencies at DER premises –** A first responder such as a firefighter may not be familiar with DERs and how they operate, in order to properly and safely respond to a fire or other emergency at a premise where DER is installed. For instance, first responders may not know where to find the disconnect switch, or how to read the emergency signage, which may cause them not to enter the structure until they are certain the DER is de-energized.

- **Personnel working on a circuit with connected DER –** SDG&E or contractor personnel may not take the appropriate precautions when working on a circuit with a connected DER.

Table 2 maps the specific drivers of DER to SDG&E's risk taxonomy.

Table 2: Operational Risk Drivers

Driver Category	DER Driver(s)
Asset Failure	• Failures of voltage control devices • Reverse power flow in distribution circuits and transformers
Asset-Related Information Technology Failure	Not applicable
Employee Incident	• SDG&E personnel working on a DER circuit
Contractor Incident	• Contractor personnel working on a DER circuit
Public Incident	• Reverse power flow in distribution transformers • Outages on circuits with high DER penetration • Emergencies on circuits or premises with installed DER
Force of Nature	Not applicable

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:

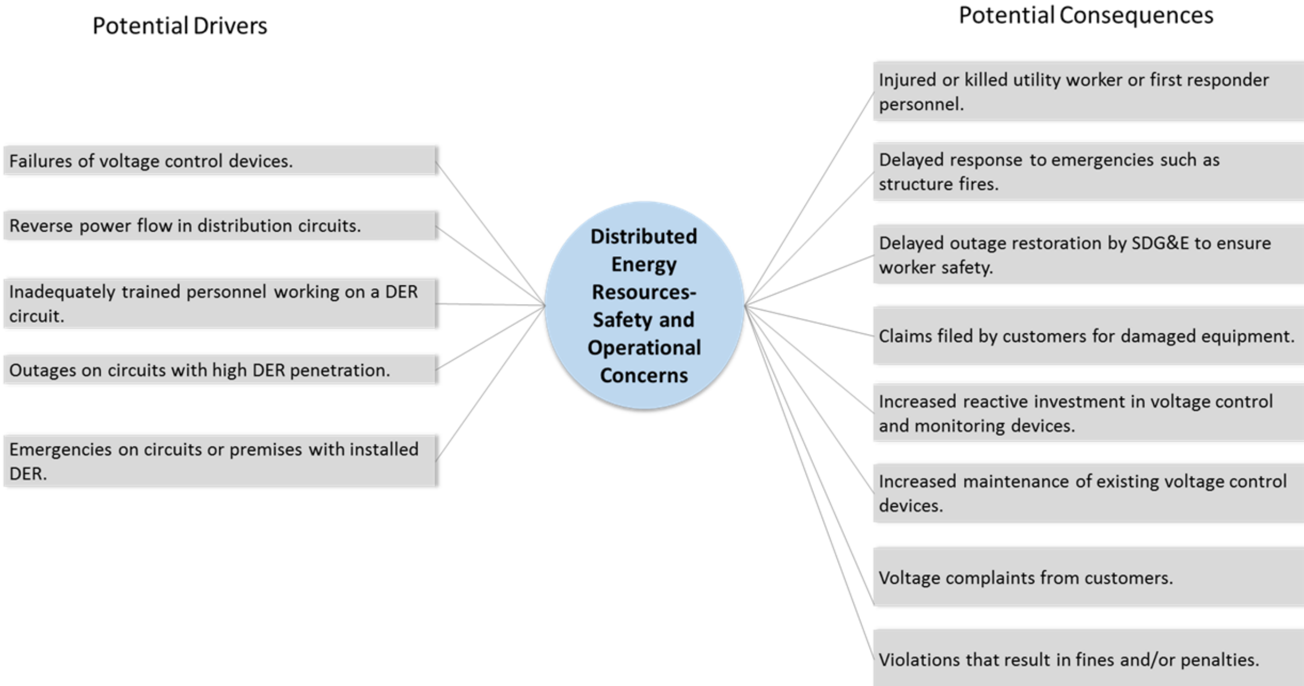
- Injured or killed utility worker or first responder personnel.
- Delayed response to emergencies such as structure fires.
- Delayed outage restoration by SDG&E.
- Damaged customer property.
- Damaged system equipment.
- Increased reactive investment in voltage control and monitoring devices.
- Increased maintenance of existing voltage control devices.
- Voltage complaints from customers.
- Financial consequences.

These potential consequences were used in the scoring of DER for 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 DER 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 distributed energy resource incident 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 DER:

- First responders and/or Company employees respond to a circuit believed to be de-energized, DER isolation fails to work, and DER energizes/back-feeds the circuit, which could result in a life-threatening injury or fatality to a first responder/employee. This could also result in moderate affects to a critical location or customer (as well as potential customer privacy implications) and/or adverse financial consequences.

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.[5] 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 DER 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	3	3	3	4	73,139

4.3 Explanation of Health, Safety, and Environmental Impact Score

During an outage on a distribution circuit, it is imperative to know that the circuit is de-energized so that utility personnel may safely work on the circuit to restore service to SDG&E customers. If a DER is energizing a circuit that utility operators and lineman believe is de-energized, a lineman or troubleshooter may unknowingly handle an energized conductor, causing injury and potentially resulting in a fatality. In addition, uncertainty regarding DER status could cause a first responder to delay action at a location where a DER is installed, potentially resulting in injury and possible fatality. Accordingly, SDG&E scored this risk a 6 (severe) in the Health, Safety, and Environmental impact category, as it has the potential to result in a few fatalities or life threatening injuries.

[5] D.16-08-018 Ordering Paragraph 9.

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:

Higher DER penetration increases operational risk on the distribution system. As discussed above, risks include delayed outage restoration by SDG&E, damaged customer equipment, increased reactive investment in voltage control and monitoring devices, increased maintenance of existing voltage control devices, and voltage complaints from customers. Delayed outage restoration will affect SDG&E reliability metrics and result in longer outages for customers. If voltage is driven outside of the voltage requirements set forth in SDG&E's Electric Tariff Rule 2 limits by increased DER penetration, then it is likely that customers will experience damage to equipment caused by voltage that is beyond the limits that their equipment was designed for. These same voltage swings in SDG&E's distribution system will result in increased maintenance of existing voltage regulating equipment, as well as an increase in investment in new voltage/reactive power regulating devices and controls. Based on this, SDG&E rates this risk a 3 (moderate) in the Operational and Reliability impact category. While this has the potential to impact more than 1,000 customers or disrupt service for one day, the operational impacts may be limited to those with DERs or individual circuits.

A score of 3 (moderate) was given in the Regulatory, Legal, and Compliance and Financial impact areas. Due to the safety and operational concerns associated with this risk, regulatory and legal consequences could arise. Further, an event that occurs related to DERs could result in damaged equipment claims filed by customers. However, the financial outcome was estimated to be between $1 million and $10 million, which equates to a 3 on the 7X7 matrix.

4.5 Explanation of Frequency Scores

Due to SDG&E's comprehensive safety policies and protocols, SDG&E is able to mitigate some of its concerns. However, with increasing levels of DER penetration the potential for an injury or death to utility or first responder personnel will occur more frequently. It is likely, however, that high penetration of DERs will result in operational constraints. SDG&E has one 12kV circuit that already required new equipment to mitigate voltage concerns caused by a large DER installation. Therefore, SDG&E rated this risk a 4 (occasional) with a frequency of potential occurrence once every 3-10 years.

5 Baseline Risk Mitigation Plan[6]

As stated above, the safety risks associated with DERs primarily deal with the potential for DERs to be energized and connected to the SDG&E system while SDG&E operators and field personnel have little to no visibility as to the DER's status. The 2015 baseline mitigations discussed below include the

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

current evolution of the utilities' management of this risk and the cost to comply with laws that were in effect at that time. The baseline mitigations have been developed over many years to address this risk.

These controls focus on safety-related impacts[7] (i.e., Health, Safety, and Environment) per guidance provided by the Commission in D.16-08-018[8] as well as controls and mitigations that may address reliability.[9] 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 DER scenarios, not just the scenario used for purposes of risk scoring.

The 2015 risk mitigation plan for DERs included a mixture of new tools, outreach, and monitoring. The new challenges presented by DERs require distribution planners to upgrade their modeling and forecasting tools, as well as to perform more precise interconnection studies to appropriately capture the effects of DER interconnections. Because DERs are relatively new to electric operations, outreach of both in-house and external stakeholders is necessary so that SDG&E employees and members of the public that may safely interact with DERs and/or the electric system. These three controls focus on the Health, Safety and Environmental impact area and/or the likelihood of an event occurring. In other words, the mitigations presented in Sections 5 and 6 are only safety-related.

1. Voltage/Power Quality Studies of DER Interconnections
   Performing voltage and power quality studies on DERs that request interconnection to SDG&E's system enable SDG&E to evaluate adverse operational impacts before the DER is connected to the system. Every project is required to be studied under Electric Rule 21, SDG&E's interconnection tariff for small generators, and projects are studied in the order they are received. Included in the study report will be mitigations that will reduce or eliminate impacts to the distribution system.

2. Improved Modeling Tools

   SDG&E over the past two years has updated its power flow software to enable modeling of DER in a time-series manner. The updated software can analyze the system over a 24-hour period, capturing the effect of variable DER on the voltage and thermal characteristics of the distribution system. SDG&E has also upgraded its forecasting software, purchasing a tool that will allow SDG&E to forecast the load of a circuit over a 24-hour period, rather than the peak load only forecasting approach that SDG&E has previously used. These improved modeling tools allow SDG&E to more accurately model and forecast DERs, increasing the accuracy of

[7] The Baseline and Proposed Risk Mitigation Plans may include mandated, compliance-driven mitigations.
[8] 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."
[9] Measures taken to impact safety may also impact reliability.

interconnection studies as well as yearly planning studies. These improved studies will more accurately capture the impacts of DERs on the system, and produce better mitigations than would otherwise be possible.

3. Interconnection Compliance

   SDG&E's interconnection compliance program provides that DERs installed on the SGD&E system utilize equipment certified by UL. They are installed in connection with local authority inspections for compliance with National Electric Code (NEC) specifications. SDG&E checks for proper signage and safety placards so that anyone approaching the DER equipment is aware of the electrical hazard and can take appropriate steps to maintain their own safety.

6 Proposed Risk Mitigation Plan

The 2015 baseline mitigations outlined in Section 5 will continue to be performed in the proposed plan, in most cases, to maintain the current residual risk level. Baseline activities identified in the Section 5 are being maintained or expanded in the years 2017 through 2019. In addition, SDG&E's proposes to include the new mitigation of an Anti-Islanding Testing Program. The expanded and new mitigations are described in detail below.

1. Power Quality Studies of DER Interconnections

   SDG&E anticipates that this mitigation will be expanded during the 2017-2019 timeframe. Expansion of this activity includes the same activities identified above, but the number of interconnections is expected to increase due to increasing DER adoption rates and the availability of Integration Capacity Maps online resulting from the Distribution Resources Plan proceeding. This helps SDG&E maintain its safety levels by keeping up with the increasing number of requested interconnections.

2. Improved Modeling Tools

   SDG&E anticipates that this mitigation will be maintained during the 2017-2019 timeframe. SDG&E made a capital investment in 2015, as discussed in Section 5 and illustrated in Section 7, for improved modeling tools. There are on-going maintenance costs associated with software licensing for these modeling tools. Again, this mitigation aims to help SDG&E improve safety.

3. Increased Outreach Program

   SDG&E routinely works with first responders to educate them on how to respond to emergencies when dealing with electric system equipment. In fact, SDG&E currently conducts first responder training to effectively prepare those involved to collaboratively work together during emergency situations. SDG&E also works to inform the public on the hazards regarding electricity and gas through bill inserts, billboards, commercials, and other methods. Topics typically include what to do when a wire goes down, how to respond to a gas leak, and more.

The proposed outreach program would add to SDG&E's existing outreach efforts regarding DERs, including any safety issues that may be encountered by the public and first responders. The result of the outreach program would be increased awareness on the part of first responders and the public as to how to work with and around DERs.

4. Interconnection Compliance
   SDG&E anticipates that this mitigation will be expanded during the 2017-2019 timeframe. Expansion of this activity includes the same activities identified above, but the number of interconnections is expected to increase due to increasing DER adoption rates.

5. Anti-Islanding Testing Program
   As part of its interconnection process, SDG&E requires that all inverters be certified by the Underwriter's Laboratory (UL). This UL certification indicates that the inverter model has passed a series of tests, including a test of the anti-islanding functionality that is required to connect to the utility grid. During the course of receiving a PTO, SDG&E also checks that a disconnect switch is correctly installed when appropriate. SDG&E does not test the anti-islanding function, instead relying on the UL certification for compliance.

The anti-islanding testing program would "test" the anti-islanding function on a routine basis, using the customer's Smart Meter or through a technology solution, to reduce the possibility that a malfunctioning inverter could energize the distribution system during an outage. Because the anti-islanding protection is the primary mechanism to avoid potential safety events related to this risk, it is imperative that it is working properly. Further, the inverter is owned by a customer and located on a customer's premise making the working condition also unknown to SDG&E. Given these factors, SDG&E proposes to test the anti-islanding function on a customer's DER, or other program to address this issue. Additional details of the proposed testing program will be addressed in SDG&E's Test Year 2019 General Rate Case Application, which will be filed on September 1, 2017.

As mentioned, the equipment is generally on a customer's premise. Therefore, SDG&E plans to do the "test" using the customer's Smart Meter or through a technology solution. This may require a brief outage, approximately less than five minutes, to verify that the DER does indeed stop feeding electricity to the electric grid and the anti-islanding protection is working as intended.

7 Summary of Mitigation Benefits

Table 4 summarizes the 2015 baseline risk mitigation plan, the risk driver(s) a control addresses, and the 2015 baseline costs for DER. 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[10]
(Direct 2015 $000)[11]

ID	Control	Risk Drivers Addressed	Capital[12]	O&M	Control Total[13]	GRC Total[14]
1	Power Quality Studies of DER Interconnections	• Failures of voltage control devices • Outage on high penetration circuits • Reverse power flow on distribution transformers	$40	n/a	$40	$40
2	Improved Modeling Tools	• Failures of voltage control devices • Outages on high penetration circuits • Reverse power flow in distribution transformers	1,640	n/a	1,640	1,640
3	Interconnection Compliance	• Inadequately trained personnel working on a circuit with connected DER • Emergencies at DER premises	n/a	1	1	1

[10] Recorded costs were rounded to the nearest $10,000.
[11] 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.
[12] 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.
[13] 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).
[14] The GRC Total column shows costs typically presented in a GRC.

ID	Control	Risk Drivers Addressed	Capital[12]	O&M	Control Total[13]	GRC Total[14]
	TOTAL COST		$1,680	$0	$1,680	$1,680

SDG&E gathered the costs in Table 4 primarily using accounting information. However, because SDG&E does not track costs by activity, but rather by cost centers and capital budget codes, some assumptions by Subject Matter Experts were included to derive these costs. Accordingly, the costs provided herein are intended to be representative and not a comprehensive view of all costs related to DER.

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[15]
(Direct 2015 $000)

ID	Mitigation	Risk Drivers Addressed	2017-2019 Capital[16]	2019 O&M	Mitigation Total[17]	GRC Total[18]
1	Power Quality Studies of DER Interconnections	• Failures of voltage control devices • Outage on high penetration circuits • Reverse power flow on distribution	$600 - 1,200	n/a	$600 - 1,200	$600 - 1,200

[15] Ranges of costs were rounded to the neared $10,000.
[16] 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.
[17] The Mitigation Total column represents the total amount, which includes GRC items as well as any applicable non-GRC items.
[18] The GRC Total column is only presenting those costs which are typically represented in a GRC.

		transformers				
2	Improved Modeling Tools	• Failures of voltage control devices • Outages on high penetration circuits • Reverse power flow in distribution transformers	n/a	50 - 130	50 - 130	50 - 130
3	Increased Outreach Program	• Inadequately trained personnel working on a circuit with connected DER • Emergencies on DER premises	n/a	300 - 500	300 - 500	300 - 500
4	Interconnection Compliance	• Inadequately trained personnel working on a circuit with connected DER • Emergencies at DER premises	n/a	760 - 960	760 - 960	0
5	Anti-Islanding Testing Program	• Failures of voltage control devices • Inadequately trained personnel working on a circuit with connected DER • Emergencies at	n/a	200 - 300	200 - 300	200 - 300

		DER premises				
	TOTAL COST		$600 - 1,200	$1,310 - 1,890	$1,910 - 3,090	$1,150 - 2,130

☐	Status quo is maintained
☐ (shaded)	Expanded or new activity
*	Includes one or more mandated activities

The costs shown in Table 5 were forecasted using an average of the past three years for activities that are currently performed by SDG&E. For the Anti-Islanding Testing Program, the costs were forecasted using a method similar to how Corrective Maintenance Programs are performed. It was assumed that every current and future DER installation with an inverter would be tested once every five years by SDG&E personnel.

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."[19] 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.[20]

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

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

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.[21] 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.

[21] 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 DER risk. The RAMP Approach chapter in this Report provides a more detailed example of the calculation used by the Company.

SDG&E grouped the mitigations as follows:

(a) Interconnection studies and modeling (current controls)

- Conduct interconnection studies and incorporate DER into circuit modeling to ensure installed DER capacity does not exceed overnight load minima and backflow limiters are configured correctly.

(b) Baseline Placard Compliance Enforcement (current controls)

- SDG&E's Distribution Interconnection Information System (DIIS) Program, uses Smart Meter Data to identify unaccounted sources of power. Unknown back feed indicates a possible unregistered DER source that can be investigated and corrected through a multi-step process including auto-notification, formal letter, phone contact, field contact, and, finally, disconnection.

(c) Enhanced Training for first responders (incremental mitigations)

- Education and Awareness
  - Aggressive outreach program to educate first responders on DER
  - Virtual application process and approvals
- Safety placards

(d) Inspection program for inverters at DER installations (incremental mitigations)

- Inspect installations on a rotating five-year basis, addressing 20% of the installed base of 100,000+ installations annually and correcting any issues found.

For both current controls and incremental mitigations, residual risk was first determined by establishing the inherent likelihood of injury starting with the number of routine events per year, determining the proportion of events in which the hazard would be present, and the proportion of those which might result in serious injury. The anticipated risk reductions were then calculated by identifying the ways in which the mitigations would reduce either the number of hazardous locations, or the likelihood that an encounter with a hazardous situation would result in an injury.

Likelihood of Injury

- **First Responder Injury Due to Improperly Marked DER**

Two of the proposed mitigations, Baseline Placard Compliance Enforcement and Enhanced Training for First Responders, were evaluated in the context of this outcome. The residual risk for first responder injury is a function of three variables:

Factor A - Number of estimated annual fire calls in SDGE territory: 14,971 fire calls

Factor A was determined by extrapolating 5,639 annual SDFD fire responses[22] within the San Diego population of 1,356,000[23] to the full population of people served by SDGE of 3.6 million,[24] yielding a theoretical number of annual fire calls in the SDGE territory of 14,971.

Factor B - Number of unknown DER (solar) installation present at a fire location: 5.9 fire calls or 0.0229%

Factor B was determined by the number of unauthorized DER installations that would exist in the absence of the monitoring program. This number is a function of the back feed detection program in DIS which identifies approximately 80 unknown sources per week according to SDGE subject matter experts. Given that the process of converting this unknown DER installation into a properly registered installation that meets standards includes a set of deliberate notification and investigative steps over four to eight weeks, approximately 440 unregistered sites can exist at any one time. Relative to the 1.4M SDGE meters, this is 0.03% of the total meters; thus fire fighters encounter an unregistered DER site on 4.7 of the nearly 15,000 fire calls.

Factor C – Annual number of fire fighters receiving an electrical injury when encountering an unknown DER: 0.0036 fire calls annually or 0.076%

[22] https://www.sandiego.gov/fire/about.

[23] https://www.sandiego.gov/economic-development/sandiego/population.

[24] http://www.sdge.com/aboutus.

Factor C was determined by the number of nationwide electrical injuries experienced by fire fighters (190 according to NFPA statistics[25]) relative to nearly 500,000 annual fire responses with the assumption that unregistered installation would double the nominal injury rate.

Based on these factors, the residual likelihood of an injury in this scenario is 0.004 incidents per year, or one every 279 years.

- **SDG&E Employee Injury Due to Islanding Because of Malfunctioning Inverters**

The Inspection Program for Inverters at DER Installations mitigation was evaluated in the context of this outcome. The residual risk for SDGE employee injury due to islanding as a function of malfunctioning inverters is similarly a function of three variables:

<u>Factor A – Annual number of outage events on the SDGE system</u>

A review of OMS data reveals SDGE experience approximately 1,900 outages per year, of about 500 customers each.

<u>Factor B – Rate of DER systems with malfunctioning relays across SDGE's installed base</u>

With over 100,000 DER installations across 1.4 million customers, every 500 customer outage affects an average of 36 DER customers. One in a thousand are assumed to have defective inverters.

<u>Factor C – Injury Rate when encountering islanding</u>

Due to procedures to test lines dead and ground before working, utilizing personal protective equipment, and working on all lines as though they were live, the injury rate is assumed to be 1 in 10,000.

Based on these factors, the residual likelihood of an injury in this scenario is 0.0068 incidents per year, or one every 147 years.

- **SDGE Employee Injury Due to Islanding Because of Excessive DER Capacity**

The Interconnect Studies and Modeling control was evaluated in the context of this outcome. The residual risk for SDGE employee injury due to islanding as a function of excessive DER capacity on a circuit is

<u>Factor A – Annual number of circuit lockout events on the SDGE system</u>

A review of OMS data reveals SDGE experience approximately 260 lockouts per year.

<u>Factor B – Rate of circuits with excessive DER-source power</u>

Because the existing interconnect studies and modeling, the assumed rate of over-capacity situations is assumed to be significantly low (0.1%)

<u>Factor C – Injury Rate when encountering islanding</u>

[25] http://www.nfpa.org/news-and-research/fire-statistics-and-reports/fire-statistics/the-fire-service/fatalities-and-injuries/patterns-of-firefighter-fireground-injuries.

Due to procedures to test lines dead and ground before working, utilizing personal protective equipment, and working on all lines as though they were live, the injury rate is assumed to be 1 in 10,000.

Based on these factors, and because Factor B was set significantly low, the residual likelihood of an injury in this scenario is near zero at 0.00003 events per year. However, because Factor B is non-zero, rates of improvement can be measured.

Anticipated Risk Reduction

- Baseline Placard Compliance Enforcement

The detection algorithm identifies approximately 100 new rogue installations weekly, and it is estimated that with the time it takes to get rogue installations into compliance, there is a residual volume of 440 rogue installations across SDG&E's 1.4 million customers. It is estimated that by abandoning the program, that 5,200 rogue installations would accumulate by the end of a year, an increase of 845% from the residual level of 0.004 events per year.

- Interconnection Studies and Modeling

The number of feeders with excessive DER is set at an arbitrarily low 0.1%, but without interconnect studies and modeling it is estimated that 10% of circuits could host excessive DER load within three years, a one-hundred-fold increase to 0.003 events per year.

- Enhanced First Responder Training

It is estimated by enhancing first responder training to educate them about the emerging risks inherent in DER installations, the risk of injury when encountering rogue installations may be reduced by 40% of the 0.004 events per year.

- Anti-Islanding Inspection Program

By inspecting and addressing issues on 20% of installed DER systems per year, it is estimated that the prevalence of malfunctioning relays will be reduced by 20% of the 0.0068 events per year.

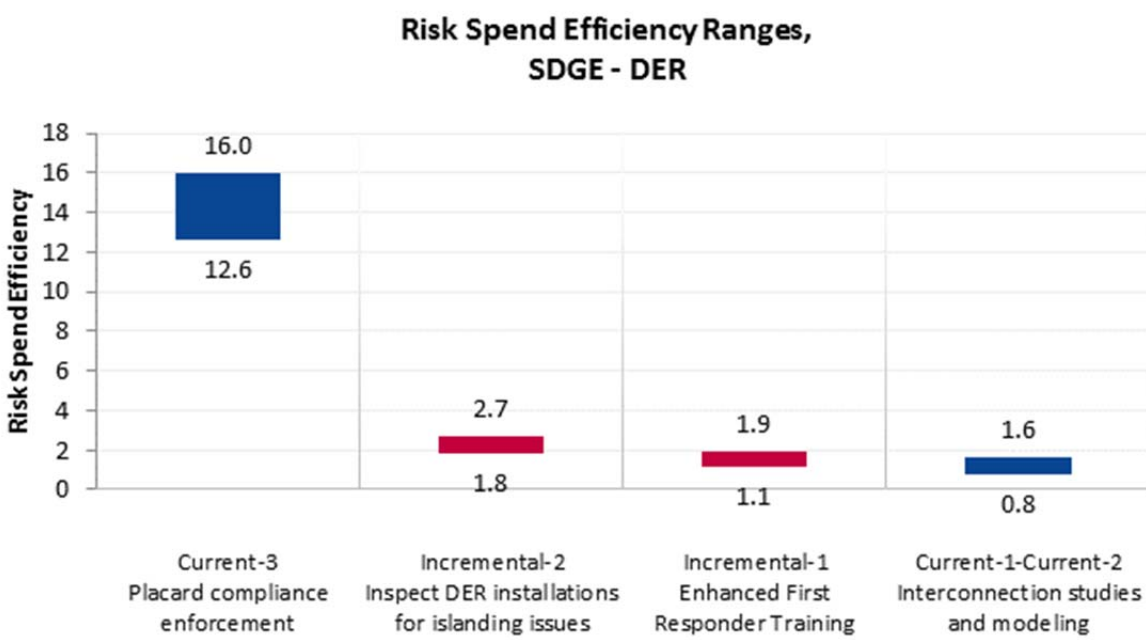
8.3 Risk Spend Efficiency Results

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:

1. Placard Compliance Enforcement (current controls)
2. DER Inverter Inspection Program (incremental mitigations)
3. Enhanced First Responder Training (incremental mitigations)
4. Interconnection Studies and Modeling (current controls)

Figure 3 displays the range[26] of RSEs for each of the SDG&E DER risk mitigation groupings, arrayed in descending order.[27] That is, the more efficient mitigations, in terms of risk reduction per spend, are on the left side of the chart.

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 DER 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.

[26] Based on the low and high cost ranges provided in Table 5 of this chapter.

[27] It is important to note that the risk mitigation prioritization shown in this Report, is not comparable across other risks in this Report.

9.1 Alternative 1 – First Responder Training

A simple training session with first responders was considered instead of a more comprehensive outreach program. This alternative would conduct twice yearly training sessions for first responders, providing them with information regarding DERs. A twice yearly training would be less costly compared to the proposed plan of outreach efforts to a wider audience who are interested, have, are impacted by and/or install DERs. However, this alternative would not provide the public with important information regarding DER equipment, and therefore was removed from consideration.

9.2 Alternative 2 – Rely on UL Certification for Anti-islanding

This alternative would rely on the status quo condition, whereby SDG&E accepts the UL certification as sufficient for verification of the anti-islanding functionality of inverters. Safety and reliability of DERs and by extension the distribution system could be at risk due to mistakes by UL and inverter manufacturers. Because of this, this alternative was dismissed from consideration.