

**CPUC Docket:** A.23-05-010  
**Exhibit Number:** TURN-05-E  
**Witness:** Jalal Awan



**PREPARED TESTIMONY OF  
JALAL AWAN**

**ADDRESSING SOUTHERN CALIFORNIA EDISON’S TY 2025 GENERAL  
RATE CASE DISTRIBUTION RELATED ISSUES AS IDENTIFIED IN  
EXHIBIT SCE-02 (‘GRID ACTIVITIES’)**

**Submitted on Behalf of**

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**February 29, 2024  
(Errata served April 11, 2024)**

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## **Testimony of Dr. Jalal Awan on Behalf of The Utility Reform Network (TURN)**

This testimony is sponsored by Dr. Jalal Awan, Energy and Climate Policy Analyst at The Utility Reform Network (TURN). Mr. Awan brings to this role over a decade of experience in electrical power systems engineering, energy systems technology, and climate policy analysis. Mr. Awan has a Ph.D. in Public Policy Analysis, specializing in Technology Policy, from the Pardee RAND Graduate School, a Master of Science degree in Green Technologies from the University of Southern California, and a Bachelor of Science in Electrical Power Systems Engineering from the University of Engineering and Technology, Lahore. For details, please refer to Attachment 1.

### **1. INTRODUCTION:**

SCE's Transmission and Distribution (T&D) infrastructure provides electricity service to more than 15 million people within a 50,000 square-mile area covering central, coastal and Southern California communities.<sup>1</sup> SCE's Transmission system comprises over 13,000 miles of transmission lines that operate at voltage levels of 55-500kV, in addition to over 5,000 miles of fiber-optic cable.<sup>2</sup> SCE's portion of the Bulk Electric System (BES) includes all transmission lines operating at 161kV or higher, which (generally) fall under FERC jurisdiction, whereas sub-transmission lines typically operating at 66 - 115kV - referred to as local distribution facilities - fall under CPUC jurisdiction and SCE operational control<sup>3</sup>. Transmission lines and distribution feeders are connected at critical points in the grid called substations, which may operate at transmission or distribution voltages and typically consist of equipment such as power transformers, circuit breakers, switchgear (relays, grounding, controls, reactors) and other equipment necessary for grid operation. Among other functions, substations step voltage levels down to distribution voltage levels (typically, 8-12kV) for distribution to residential and commercial customers<sup>4</sup>. Like transmission infrastructure, distribution infrastructure consists of major pieces of equipment, including but not limited to, poles, transformers, switches, capacitors,

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<sup>1</sup> <https://www.sce.com/about-us/who-we-are/leadership/our-service-territory>

<sup>2</sup> SCE-02, Vol.04, pg. 5

<sup>3</sup> SCE-02, Vol.04, pg. 6

<sup>4</sup> SCE-02, Vol.05, Fig. 1-1

reclosers, and circuit breakers, which typically operate for many years before they wear out. This testimony addresses the following sections of SCE-02 (‘Grid Activities’):

1. Vol. 1, Pt. 2: Infrastructure Replacement
2. Vol. 2: Distribution Inspections & Maintenance and Capital-Related
3. Vol. 4: Transmission Grid
4. Vol. 5: Substation

Across these four volumes, SCE requests \$416m (constant 2022) in O&M and \$2.496bn (Nominal) in Capital in Test Year 2025, a 13% and 85% increase from 2021 authorized amounts respectively (See Appendix 1a).

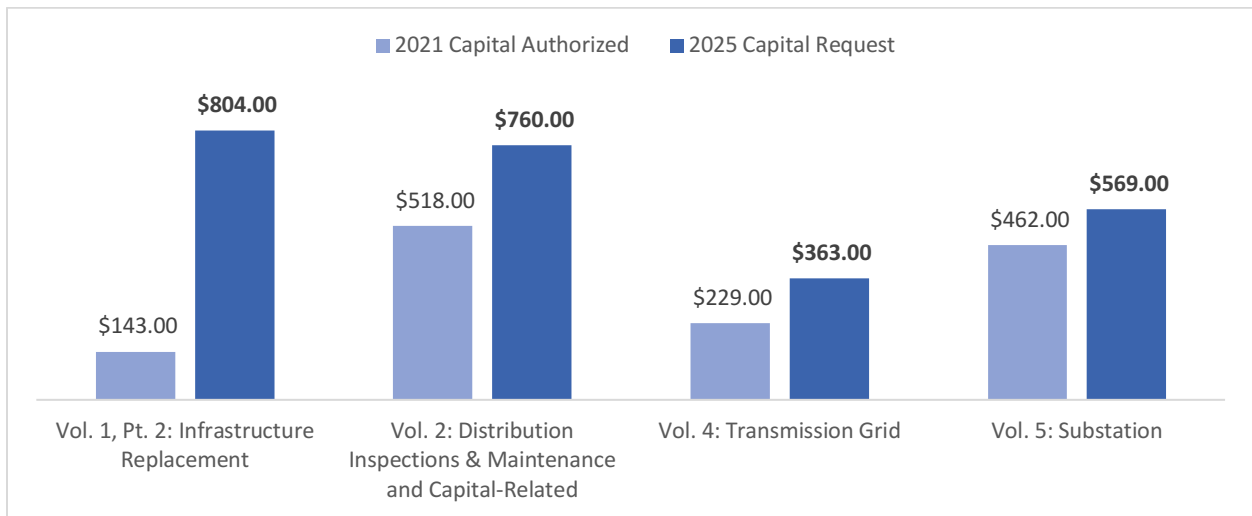


Figure 1 Capital Comparison (2021 Authorized vs. 2025 Requested, Nominal \$m)

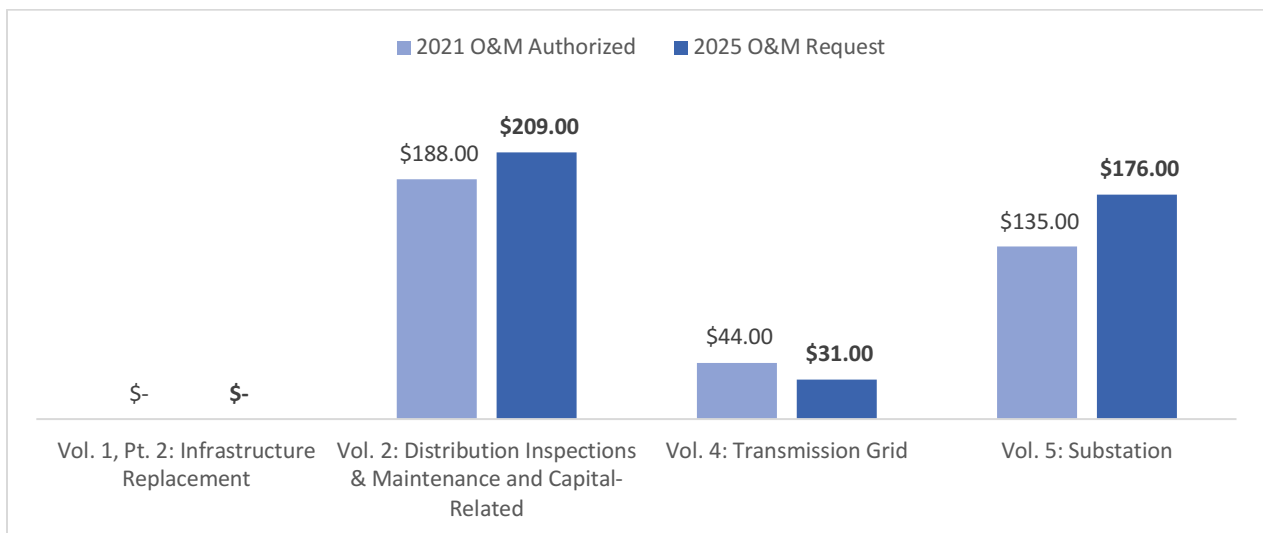


Figure 2 O&M Comparison (2021 Authorized vs. 2025 Requested, Nominal \$m)

## Summary of Recommendations:

For SCE-02 Vol. 02: Distribution Inspections & Maintenance and Capital-Related:

- TURN recommends reevaluation of the Inspect App's deployment scope, suggesting a reduced DIMP forecast due to calculated inspection times of 17 to 50 minutes per structure.

For SCE-02, Vol. 5: Substations (Substation Infrastructure Replacement):

- TURN recommends a focused replacement of 1088 circuit breakers rated "Poor" or "Very Poor" with a program cost of \$294.7 million (Nominal) compared to SCE's 1,197 replacements with \$325.9 million forecast.
- TURN recommends replacing 151 transformers rated "Poor" and "Very Poor" out of SCE's proposed 213 from 2023-2028, at a total cost to \$262,896 million (Nominal) against SCE's \$385,070 million (Nominal).

For SCE-02 Vol. 01 Pt. 02: Distribution Infrastructure Replacement:

- TURN recommends rejection of SCE's proposed Overhead Conductor Program (OCP) scope except for small-gauge wire replacements (~634 miles) at a cost of \$396.5m (Nominal) from 2023-2028 and proposes exclusion of SCE's planned bare conductor replacements (117 miles in 2023 and 91 miles in 2024). SCE's proposal for the program would cost ratepayers \$1.464bn (Nominal) from 2023-2028.
- TURN recommends 870 miles replacement for the Underground Cable Replacement (UCR) program from 2023-2028 at a cost of \$214.631 million (Nominal) against SCE's 1,670 miles replacement at \$416.450 million (Nominal), targeting 60-70% of the projected risk reduction. Moreover, TURN provides a correction of SCE's estimate, based on excluding Employee Compensation Program cost<sup>5</sup>.

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<sup>5</sup> This correction is in line with PubAdv-SCE-140-GAW.

## 2. SCE-02 Vol. 02: Distribution Inspections & Maintenance and Capital-Related

SCE forecasts \$209m (Constant 2022 \$) in O&M expenses in TY 2025 and \$760m (Nominal \$) in capital expenditures in 2025 for its Distribution Inspections & Maintenance and Capital-Related Expense activities.

Of the amounts identified above, O&M Maintenance for 2025 is ~\$112.5m (constant 2022) and Distribution Preventive and Breakdown Capital Maintenance for 2025 is ~\$404m (nominal).<sup>6 7</sup>

2.1 SCE's Distribution Inspection and Maintenance Program (DIMP) has experienced significant variability in Authorized vs. Recorded expense:

The Distribution Inspection and Maintenance Program (DIMP) is a comprehensive program aimed at ensuring the reliability and safety of the electrical distribution system, and addressing both regulatory mandates, specifically General Orders GO 95, 128, and 165, and SCE's own internal standards, which often exceed the minimum requirements set by regulations.<sup>8</sup> DIMP involves continuous, company-wide efforts to maintain and inspect SCE's distribution grid, which includes both planned and unplanned work. The program identifies necessary maintenance through scheduled and field inspections, post-emergency assessments, and the initiation or modification of programs. This process categorizes maintenance activities into three types: repairs conducted by inspectors, repairs by line crews, and replacements by line crews.<sup>9</sup>

SCE's recorded costs for activities under DIMP have varied substantially from authorized costs numbers. In 2021, SCE's actual costs exceeded authorized O&M expenses (\$175m) in several categories.<sup>10</sup> Distribution Ground Inspections went over by \$9.225m, and the Patrolling and Locating Trouble program exceeded authorized amount by \$3.941m, primarily due to the "unpredictable" nature of the tasks involved.<sup>11</sup> Furthermore, Distribution Preventive and Breakdown Capital Maintenance exceeded the authorized amount (\$390m, nominal) by

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<sup>6</sup> SCE-02, Vol.02 (Figure II-8, pg.22)

<sup>7</sup> SCE-02, Vol.02 (Figure II-7, pg.16)

<sup>8</sup> SCE-02, Vol.02 (lines 7-9, pg.5)

<sup>9</sup> SCE-02, Vol.02 (lines 21-22, pg.4))

<sup>10</sup> SCE-02, Vol.02 (Figure II-3, pg.6)

<sup>11</sup> SCE-02, Vol.02 (line 1, pg.7)

\$45.578m, largely due to increased activities in High Fire Risk Areas and additional costs from mid-2020 pole-related maintenance work not included in the 2021 authorized budget.<sup>12</sup>

Conversely, in 2018, SCE recorded expenses below the authorized amounts for both O&M and Capital Maintenance, by \$21.508m and \$20.321m, respectively.<sup>13</sup> These numbers were primarily attributed to resource reallocation towards intensified inspections in high fire risk zones and changes in maintenance repair scheduling.<sup>14</sup>

## 2.2 Maintenance Activities under DIMP show a decreasing trend:

SCE's Distribution Infrastructure Maintenance Program (DIMP) categorizes maintenance into a priority system based on risk and impact to safety and reliability: Priority 1 (P1) for immediate high-risk issues, Priority 2 (P2) for moderate risk requiring action within up to 36 months, Priority 3 (P3) for low risk and regulatory compliance issues, and Priority 9 (P9) for on-the-spot repairs by inspectors.<sup>15</sup> P1 or breakdown maintenance activities are unplanned and may include "...SCE equipment and structures that are damaged, compromised or have failed in service..."<sup>16</sup> Planned or preventive maintenance work is comprised of repairs to SCE's equipment and structures recorded as P2 and P3 items, primarily driven by issues identified through inspection activities. This also includes P9 or 'find and fix' notifications described above.

Looking at the maintenance order in aggregate serves as a barometer for the effectiveness of the utility's maintenance operations.<sup>17</sup> TURN's analysis of SCE's maintenance activities through the percentage change in work orders shows an appreciably decreasing trend in preventive and breakdown maintenance notifications from 2018-2022. Notably, in 2018 (baseline for below plots), SCE's recorded Distribution Breakdown and Preventive Maintenance expenses were actually lower than usual due to a temporary change in maintenance repair scheduling, where SCE employed dedicated personnel responsible for performing maintenance activities to

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<sup>12</sup> SCE-02, Vol.02 (Figure II-4, pg.7)

<sup>13</sup> SCE 2021 GRC, SCE-02 Vol. 1, Pt. 2

<sup>14</sup> D21-08-036, pg. 50

<sup>15</sup> TURN-SCE-015, Q03.a

<sup>16</sup> SCE-02, Vol. 02, pg. 17

<sup>17</sup> TURN-SCE-015, Q03.b

accommodate the Enhanced Overhead Inspection (EOI) activity.<sup>18</sup> Despite this low baseline, the trend in SCE's maintenance activities from 2018 to 2022 reveals a decline in closed (or completed) capital and O&M notifications for both preventive and breakdown maintenance, alongside an uptick in pending work (see Appendix 2a). In an ideal maintenance regime, the trend of closed or completed notifications should exhibit an upward sloping or stable trajectory, reflecting the timely and consistent resolution of maintenance issues.<sup>19</sup> Concurrently, pending notifications should demonstrate a downward trend, indicating an efficient throughput in addressing and reducing backlog, critical for maintaining system integrity and operational reliability.

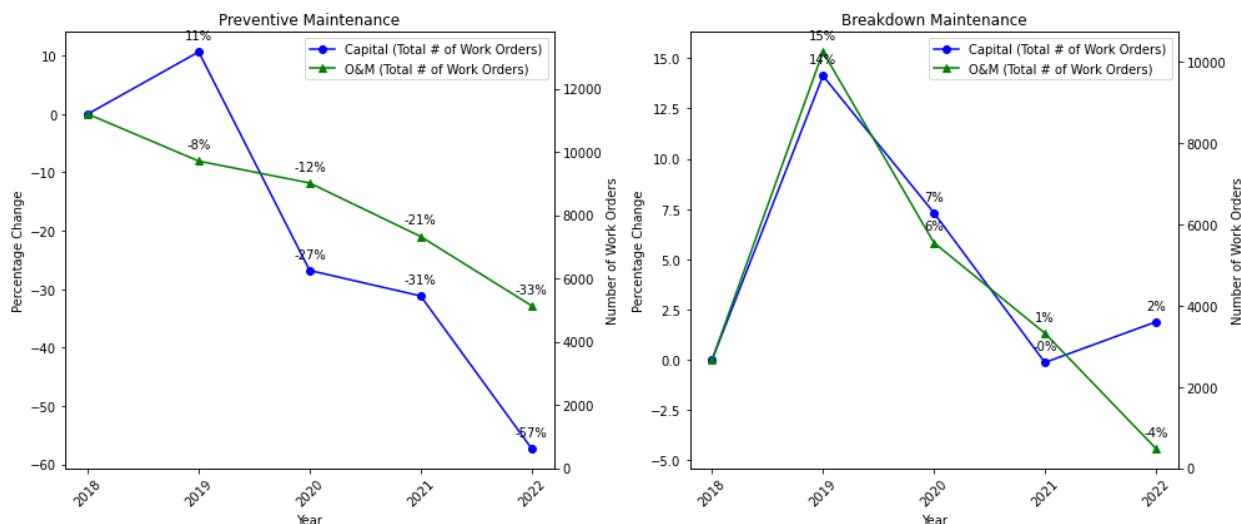


Figure 3 Trend analysis of Preventive and Breakdown maintenance activities (2018-2022).

### 2.3 Analysis of Maintenance Activities suggests reliance on specific personnel / activities:

Based on data received from SCE on notification triggers for preventive and corrective maintenance, approximately 80% of preventive (O&M / Capital) and breakdown (O&M/Capital) maintenance relies heavily on underground and overhead detail inspections and breakdowns

<sup>18</sup> D21-08-036, pg. 50

<sup>19</sup> While not directly comparable, the Six Sigma approach to minimizing standard deviation and variation exemplifies operational efficiency in complex organizations.

found by troublemen, respectively. Given legacy programs such as Annual Grid Patrols, and SCE’s recent increase in contractor workforce, it is imperative to ensure that SCE’s full workforce is diligent and engaged in ensuring a reliable, safe grid and highlighting preventive and breakdown maintenance during routine patrols.

The data show that a substantial portion of SCE's maintenance notifications for preventive and breakdown maintenance originate from underground detail inspections and reports by troublemen, respectively. However, with around 20 sources for preventive and 10 for breakdown maintenance beyond these, the 'Other' triggers also require attention.<sup>20</sup> The reliance on a subset of activities / personnel for maintenance warrants further investigation, as it may contribute to the observed decline in preventive maintenance notifications as shown in the previous section.

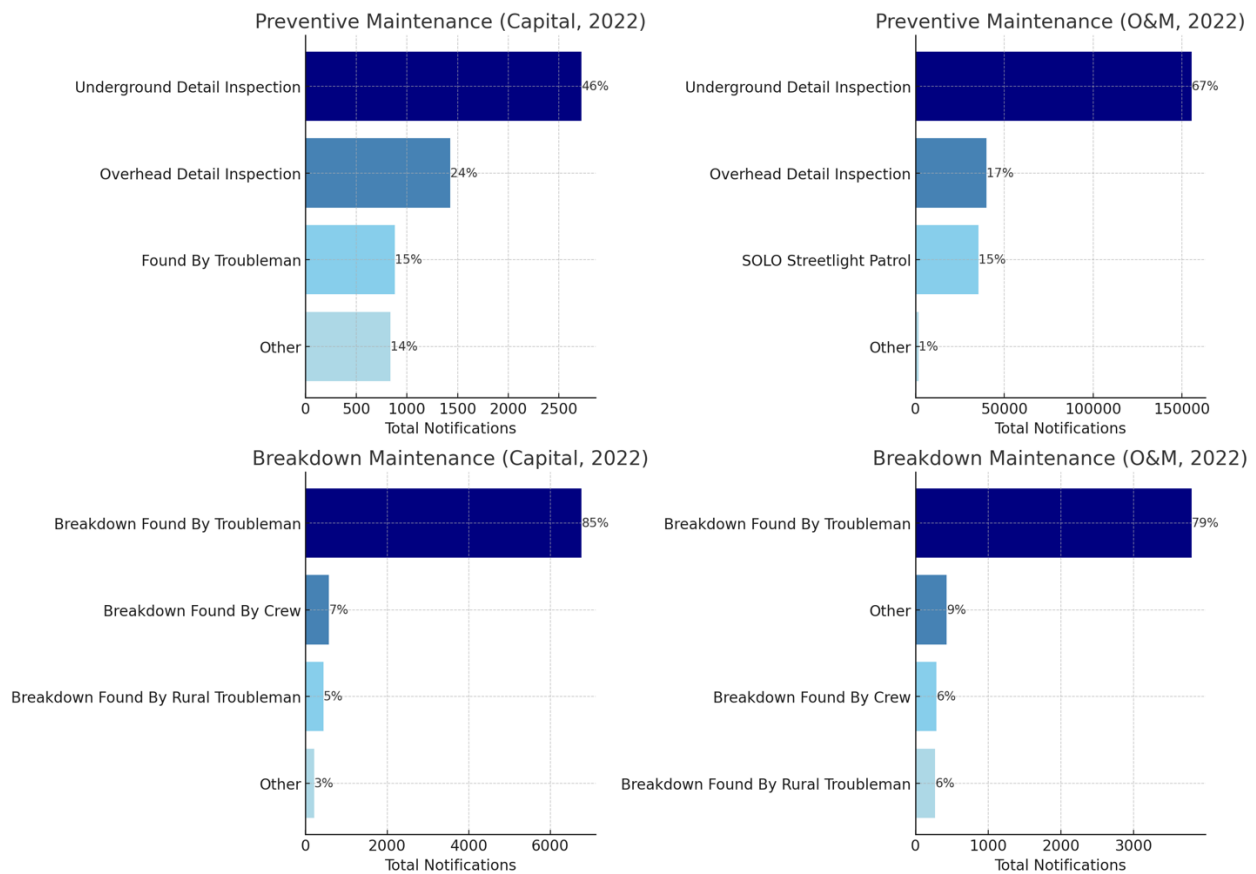


Figure 4 Maintenance Activities by activity trigger (2022)

<sup>20</sup> TURN-SCE-015, Q03.c

## 2.4 The use of Inspect App under DIMP may be an overkill:

TURN's examination of SCE's maintenance practices suggests a need to scrutinize the cost-effectiveness of the Inspect App within the distribution system's operational framework.

SCE's shift to a more detailed Distributed Ground Inspection (DGI) process in 2020, involving reliance on an Inspect App with 80-161 survey questions and mandatory photographs for each structure, significantly extended inspection durations.<sup>21</sup> SCE notes that: "...The adoption of Inspect App required the purchase of iPads, chargers, docking stations, and high zoom digital cameras to support the improved process. Due to this change, SCE was required [to] increase the number of contractors to support this effort..."<sup>22</sup> SCE further states that the Inspect App software added an additional 161 questions to each inspection (depending on structure) and that:

"...Shifting to a more comprehensive inspection led to inspection time per structure nearly tripling. This shift resulted in higher costs for the program..."<sup>23</sup>

We find that the 'tripling' of time may be a substantial underestimation of time taken to complete Inspect App surveys, whereas the benefit of the widespread use of Inspect App based inspections remains unclear. TURN notes that no reference to the use of Inspect App was found in the Commission's decision (D.21-08-036) to SCE's 2021 GRC application.

### 2.4.1 TURN's Recommendation:

**TURN recommends a reevaluation of the Inspect App's deployment for routine, compliance-based activities, and a corresponding reduced DIMP forecast. The absence of demonstrated advantages over traditional inspection methodologies, previously authorized in past GRCs, calls for this reconsideration. Given high inspection times of 17 minutes to 50 minutes per structure (excluding inspections that take 5 hours or more), TURN contends that its use in inspections in High-Fire Threat Districts (SCE-04, Vol. 05, Pt. 3) may still be prudent, subject to more data. TURN notes that a program forecast as a result of this recommendation is not included due to lack of relevant supporting data regarding Inspect App use.**

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<sup>21</sup> SCE-02, Vol.02, pp. 10

<sup>22</sup> SCE-02, Vol.02, Pg. 12 (lines 9-11)

<sup>23</sup> SCE-02, Vol. 02, pp.6 (lines 6-8)

2021 recorded O&M costs for DIMP were \$12m (constant 2022 \$) higher than authorized for 2021. SCE attributes part of this cost over-run, i.e., the \$9.225m (constant 2022 \$) over-run in 2021 authorized vs. recorded costs for Distribution Ground Inspections, to “... an enhanced approach, principally founded upon implementing the Inspect App software...” The remainder was attributed to the Patrolling and Locating Trouble activity, deemed “unpredictable” by SCE, which experienced a cost overrun of \$3.941m (constant 2022 \$).<sup>24</sup>

#### 2.4.2 Geographical Scope of Inspect App-based Inspections:

Distribution Ground Inspections using the Inspect App are completed based on “... wildfire risk and/or by compliance schedule”.<sup>25</sup> Based on 2023 data obtained by TURN, Inspect App based surveys are conducted all over SCE’s service territory, and include “... Distribution Ground and Aerial High Fire Inspections (discussed in SCE 04 Volume 5 Part 3) and Distribution ground only compliance Inspections (discussed in SCE 02 Volume 2) ...”<sup>26</sup>

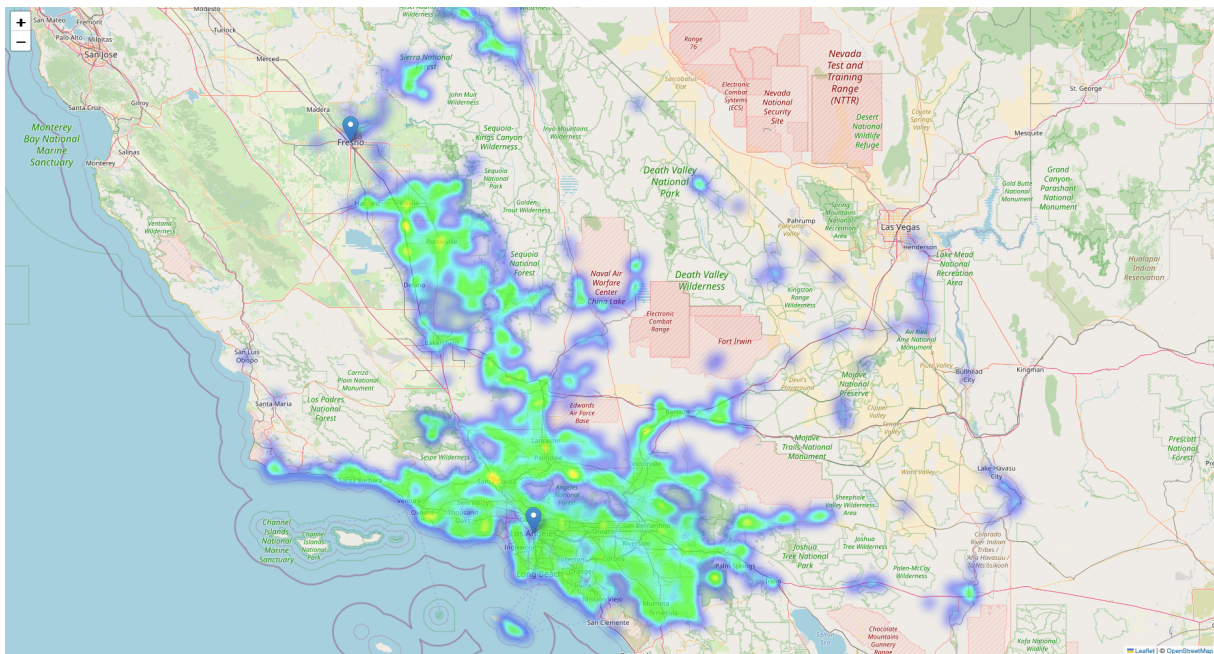


Figure 5 2023 Heatmap of Inspect App Utilization indicating areas of intensive Survey Activity

<sup>24</sup> SCE-02, Vol. 02, pp.6 (lines 4 and 9)

<sup>25</sup> TURN-SCE-015, Q4-b

<sup>26</sup> TURN-SCE-015, Q4-a

2.4.3 Time taken to complete Inspect App surveys is grossly under-estimated:

In response to TURN’s data request on Inspect App-based inspections, SCE provided the following table for Inspect App surveys and average time per survey:

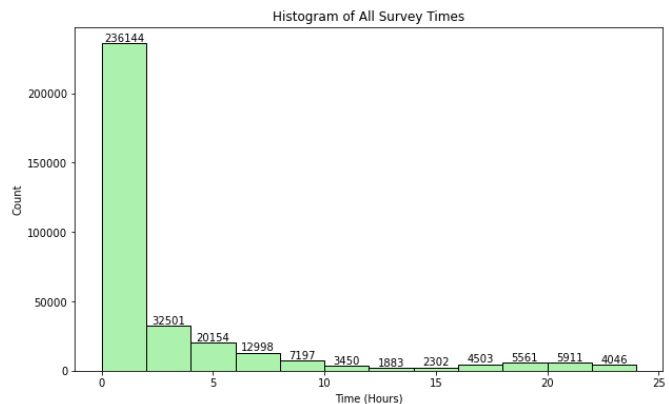
Inspector	Inspect App Surveys	Time (excluding surveys over 90m)
SCE	127,642	0:20:35
Non-SCE	209,008	0:19:51
Total	336,650	0:20:11

SCE explains that activities such as traveling, mobilizing, and demobilizing are excluded from the time data and any inspection times greater than 90 minutes are also excluded.

As such, the average time of approximately 20 minutes per structure is under-estimated and Inspect App based inspections likely exceed the tripling of inspection time that resulted in an approximately \$9m over-run in 2021 authorized vs. recorded costs.

Per TURN’s analysis, average Inspect App survey time ranges from 17 minutes to 50 minutes per structure (excluding inspections that take 5 hours or more) and its use / deployment should therefore be restricted to inspections in High Fire Threat Districts.

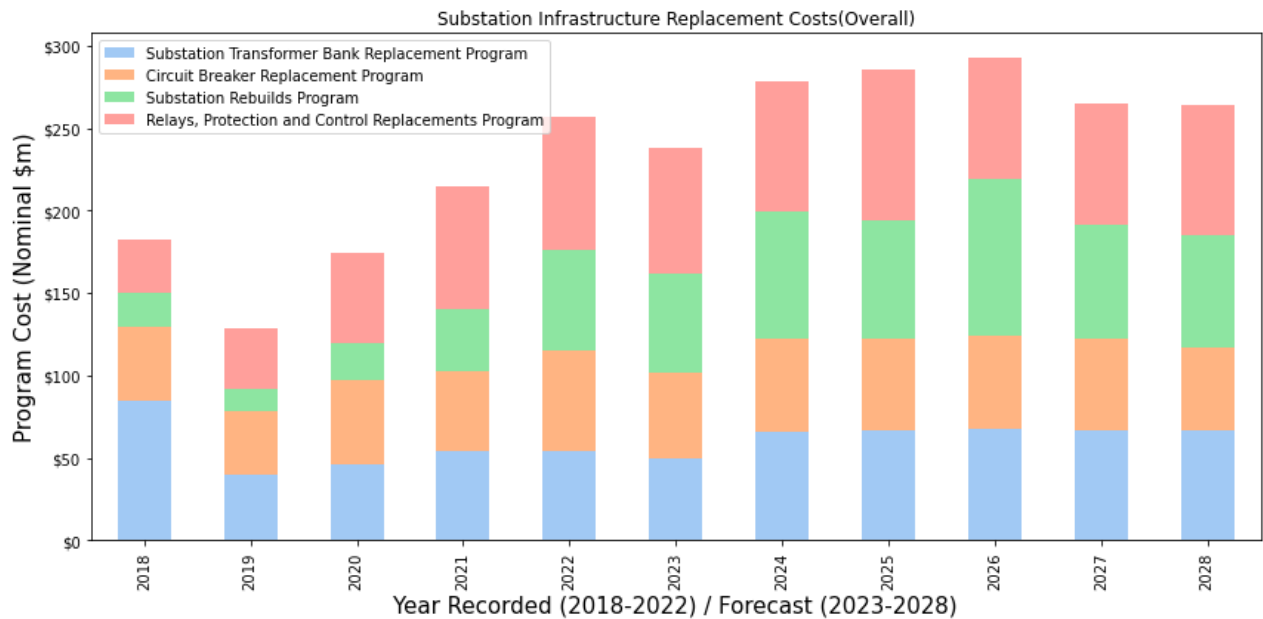
Survey Inclusion Cutoff	Average Time to Complete Survey
Up to 1 hours	00:17:56.331090832
Up to 2 hours	00:22:38.170671484
Up to 3 hours	00:31:48.951868627
Up to 4 hours	00:40:57.082834085
Up to 5 hours	00:50:17.466754219
5 hours or more	12:20:12.716311064



### 3. SCE-02, Vol. 5: Substations (Substation Infrastructure Replacement)

This program focuses on pre-emptive replacement of equipment and structures that are “...poor health-indexed, aged, and obsolete...”<sup>27</sup> By prioritizing proactive replacement, SCE aims to execute these replacements efficiently and safely, leveraging “... age, manufacturer ratings, inspection, repair, and maintenance records, testing results, performance history, etc...”<sup>28</sup>.

Infrastructure replacement includes replacing power transformers, circuit breakers, and other substation components before they fail, thus maintaining operational efficiency and minimizing customer impact.



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Substation Transformer Bank Replacement Program	\$84,588	\$39,442	\$46,416	\$53,675	\$54,511	\$49,658	\$65,945	\$66,405	\$67,632	\$67,701	\$66,729
Circuit Breaker Replacement Program	\$44,467	\$39,148	\$51,010	\$49,218	\$60,541	\$52,202	\$56,389	\$55,504	\$56,465	\$55,179	\$50,056
Substation Rebuilds Program	\$21,096	\$13,382	\$21,921	\$37,216	\$61,284	\$60,198	\$76,497	\$72,339	\$94,689	\$69,557	\$68,037
Relays, Protection and Control Replacements Program	\$32,245	\$36,402	\$54,815	\$74,823	\$80,467	\$76,297	\$79,146	\$91,197	\$74,114	\$73,136	\$79,007
<b>Totals</b>	<b>\$182,395</b>	<b>\$128,374</b>	<b>\$174,162</b>	<b>\$214,931</b>	<b>\$256,803</b>	<b>\$238,356</b>	<b>\$278,177</b>	<b>\$285,445</b>	<b>\$292,900</b>	<b>\$265,573</b>	<b>\$263,830</b>

Figure 6 Substation Infrastructure Replacement Cost Forecast (SCE-02, Vol.05, pp. 133, Table V-18)

<sup>27</sup> SCE-02, Vol.05, pp. 132, line 5

<sup>28</sup> SCE-02, Vol.05, pp. 132, lines 30-31

SCE's strategy of extensive substation infrastructure replacement demands a critical evaluation of its capital expenditures. While the strategy emphasizes preemptive replacement of equipment to improve safety and reliability, it is essential to exercise rigorous due diligence in line with affordability concerns discussed in TURN-02. The upward trajectory of SCE's infrastructure replacement expenditure<sup>29</sup>, contrasted with the downward trend in the volume of routine maintenance activities<sup>30</sup>, raises concerns about the efficacy and necessity of some of the proposed replacements discussed below.

Given the substantial forecast of \$1.629 billion for substation infrastructure replacement from 2023 to 2028, it is prudent to question whether these replacements are uniformly necessary or if they are proposed in excess of what is required for a reliable and safe electricity supply. Such scrutiny should extend beyond the face value of SCE's assertions and require a demonstrable justification for each proposed replacement, focusing on specific equipment health and its impact on safety and reliability.

### 3.1 Circuit Breaker Replacement Program:

TURN observes a notable disparity in SCE's Circuit Breaker Replacement Program, with a low number of replacements paired with disproportionately high costs. This variation between costs and number of circuit breakers replaced persists across years, regardless of the voltage levels of the breakers replaced. While it is understood that breakers operating at medium voltage (MV) or high voltage (HV) levels are likely to be more costly than those at low voltage (LV) levels, and that increases in unit costs may account for some of the observed variance, the magnitude of the cost variation calls for a closer examination. Specifically, there should be a review comparing the actual voltage levels of the replaced breakers against the forecasted voltage levels. However, TURN notes that conducting such an analysis is challenging due to SCE's workpapers categorizing breakers into a broad grouping for program-level forecasts, only distinguishing between higher voltage breakers ranging from 220 to 500 kV and lower voltage breakers ranging from 2.4 to 115 kV.

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<sup>29</sup> SCE-02, Vol.05, pp. 134, Figure V-58

<sup>30</sup> Appendix 2a

The following recorded and forecast costs and numbers demonstrates the difference between costs incurred and number of circuit breakers replaced:

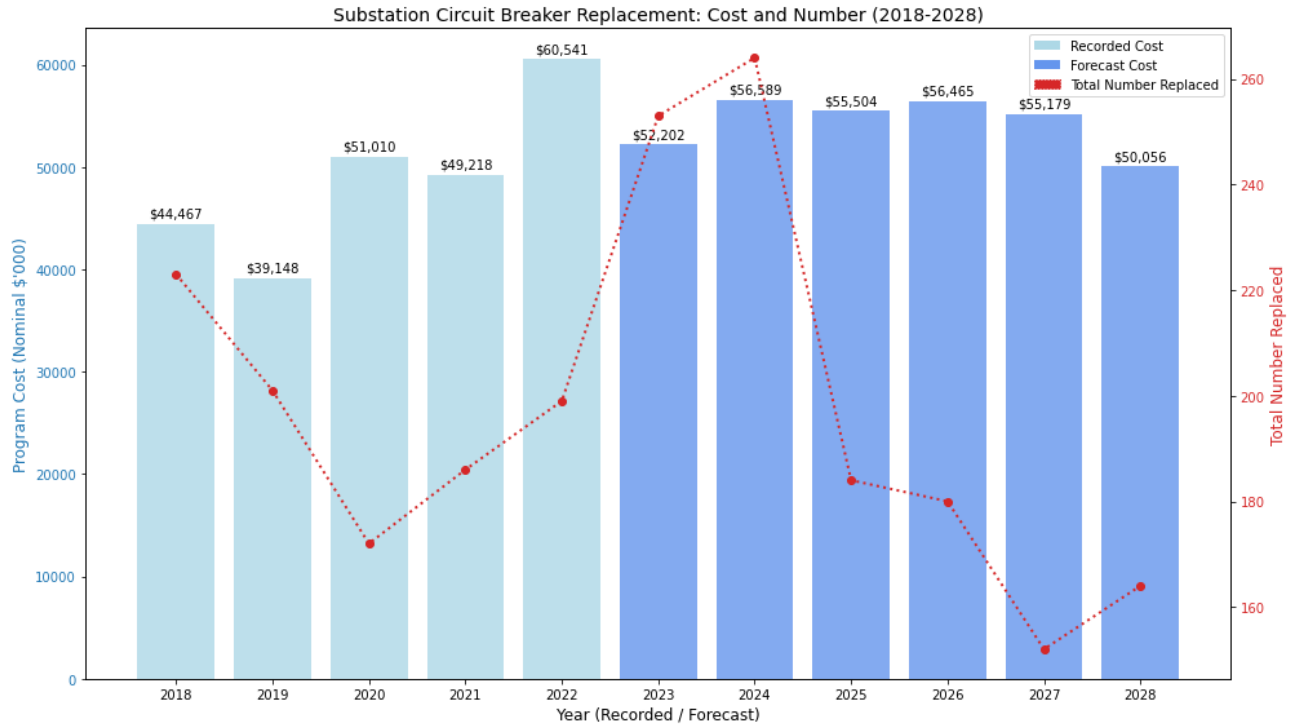


Figure 7 Recorded and Forecasted Costs for Substation Circuit Breaker Replacement Program vs. Number of CBs replaced.

The higher costs incurred on the relatively low number of replacements is cited to be driven by “increased material and labor costs.”<sup>31</sup> SCE notes that: “...The CPUC authorized \$43.372 m in the 2021 GRC decision for replacement of 205 CBs. SCE incurred \$49.218 m for the Circuit Breaker Replacement Program in 2021 and replaced 187 CBs. This variance was driven by increased material and labor costs in 2021...”<sup>32</sup>

<sup>31</sup> SCE-02, Vol.05, line 4, pp. 142

<sup>32</sup> SCE-02, Vol.05, lines 2-3, pp. 142

### 3.1.1 TURN’s Recommendation:

**TURN recommends SCE adopt a more focused strategy for circuit breaker replacements - with an authorized program cost of \$294.7 (Nominal) compared to SCE’s estimated forecast of \$325.9m (Nominal) – and targeting only those 1088 circuit breakers rated “Poor” or “Very Poor” per the Health Index against SCE’s plan of 1,197 replacements at a rate of 200 per year. TURN further calls for a detailed reanalysis of unit costs and proposes using exact voltage classes for circuit breakers, ranging from 4 kV to 500 kV, to enhance forecast precision and transparency as opposed to the two broader categories of circuit breakers by voltage class currently used.**

TURN recommends a 10% reduction in capital expense for the replacement of 1088 CBs, as opposed to SCE’s 1,190 recommended replacements. TURN finds that with the provided data, it is justified to replace low and high-voltage Circuit Breakers in “Very Poor” condition only. Our estimate for forecast (2023-2028) capital requirements (using SCE’s unit cost estimate) is as follows:

Forecast	Total (Exclude Rebuild)		Program Forecast (TURN)*	Program Forecast (SCE)	Percentage Difference
	2.4-115kV Units	220 - 500kV Units			
2023	226	5	\$ 47,662.70	\$ 52,202.00	-9%
2024	250	0	\$ 53,588.07	\$ 56,589.00	-5%
2025	172	0	\$ 51,884.17	\$ 55,504.00	-7%
2026	155	0	\$ 48,622.64	\$ 56,465.00	-14%
2027	130	1	\$ 47,555.59	\$ 55,179.00	-14%
2028	149	0	\$ 45,477.71	\$ 50,056.00	-9%
<b>Total (2023-2028)</b>	<b>1082</b>	<b>6</b>	<b>\$ 294,790.87</b>	<b>\$ 325,995.00</b>	<b>-10%</b>

*Figure 8 Program Forecast (2023-2028) based on SCE’s unit costs and TURN’s proposed number of replacements.*

### 3.1.2 Analysis of SCE’s Circuit Breaker Replacement Program:

SCE states that: “...Over the past 13 years, SCE has experienced 70 in-service CB failures...”, a rate of ~5 CB failures per year, or 0.04% failure rate per year<sup>33</sup>. TURN agrees that in-service CB failures must be avoided – and that even one in-service failure is one too many – but SCE’s

<sup>33</sup> SCE-02, Vol.05, p. 143. The failure rate is calculated considering, on the higher end, 12,700 CBs operating in SCE’s service area during the past 13 years.

current replacement strategy may not effectively reduce the rate of failure, unless at-risk CBs are targeted more precisely and effectively, rather than through the present approach which appears to be based on replacement as opportunities arise.

SCE fails to provide reliability-related costs (i.e., CMI / SAIDI / SAIFI metrics) or safety-related costs (incidents/injuries/fatalities) due to catastrophic or non-catastrophic CB failures, nor does it justify how its proposed replacement program would reduce those costs. The utility's replacement strategy is akin to playing whack-a-mole, instead of deliberate, targeted replacement approach that tracks benefit of prior replacements in terms of improved safety and reliability metrics and devises future replacement actions accordingly.

In electrical circuits, beyond the primary defense provided by circuit breakers (CBs), several other layers of defense are employed to avoid catastrophic failure and ensure system stability and safety. It is to be noted that TURN does not contest SCE's two other major substation infrastructure replacement programs – 'Relays, Protection and Controls Replacement' and 'Substation Rebuilds Program' – with proposed capital expense of \$91.1m (Nominal) and \$72.3m (Nominal) for TY 2025 respectively. The synergies of these programs (in terms of reducing reliability/safety risks) with CB replacement are not discussed anywhere in the company's testimony. Moreover, most metal clad industrial switchgear is compartmentalized to separate the circuit breaker from other components in the switchgear for safety<sup>34</sup>. After circuit breakers, fuses serve as a secondary line of defense, offering protection by melting under excessive current conditions to interrupt the circuit. Relays constitute another sophisticated layer of defense, continuously monitoring electrical parameters such as current, voltage, frequency, and phase angle to detect and respond to abnormalities that could indicate potential issues like overloads, phase imbalances, or ground faults. Lastly, preventive measures such as regular maintenance, thermal imaging to detect overheating, and condition monitoring of equipment play a critical role in identifying potential issues before they lead to "catastrophic failure".<sup>35</sup>

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<sup>34</sup> <https://www.sciencedirect.com/science/article/abs/pii/B9780750666732500173>

<sup>35</sup> SCE-02, Vol.05, pp. 143, line 8

SCE claims that out of its total installed inventory of 12,700 CBs, approximately 2,000 are in "Poor" or "Very poor" condition. SCE forecasts replacing over 1,190 CBs from 2023 to 2028, of which roughly 680 are for the 2025 GRC period (2025-2028), at an average of 170 replacements per year<sup>36</sup>. TURN disagrees with the need for proactively replacing ~10%<sup>37</sup> of its installed substation CBs on the grounds that diagnostic testing, refurbishment, remedial work should all be relied upon as alternatives before resorting to the most costly option.

### 3.1.3 Potentially erroneous CB replacement Unit Cost Calculation:

TURN's first contention is there is wrong arithmetic behind CB unit cost calculation. SCE asserts that: "Unit costs are derived by taking total project costs divided by the number of circuit breakers replaced and then separated out by circuit breaker voltage class." However, SCE fails to demonstrate that this is how the calculations are done.

TURN noticed that, in 'WP SCE-02, Vol. 05\_CB and Transformer Cost Forecast', SCE applies double escalation in CB Average Cost Calculation tab, among other (hitherto unknown) issues due to lack of live WPs in estimating Average Unit Cost.

Voltage	Average Unit Cost (SCE)*	Average Unit Cost (TURN)**	% difference
4 - 16 kV	\$ 247,456	\$ 209,117.21	-18%
33 kV	\$ 421,716	\$ 222,478.40	-90%
66 kV	\$ 440,004	\$ 298,087.97	-48%
115 kV	\$ 461,194		N/A
220 kV	\$ 549,137	\$ 509,428.80	-8%
13.8 kV	\$ 247,456	\$ 58,288.85	-325%
500 kV	\$ 1,605,913		N/A

\*Unknown methods (no working WPs to assess method) \*\* Method detailed in WP (Note that TURN is removing 115kV and 500kV Average Unit Costs since those costs do not appear in tab "CB Average Cost Calculation" in WP SCE-02, Vol. 05\_CB and Transformer Cost Forecast. TURN will serve DR to identify unit cost calculations for the missing voltage classes)

The correct methodology entails calculating the mean of the project totals for a specific voltage level and then multiplying this average by the escalation factor (once) to achieve the average

<sup>36</sup> SCE-02, Vol.05, pp. 145, lines 9-12

<sup>37</sup> 12,700 total per SCE

escalated cost. Based on above, and per SCE’s calculation of forecasted costs across two voltage classes (2.4 – 115kV and 220-500kV), TURN vs. SCE estimates are as follows:

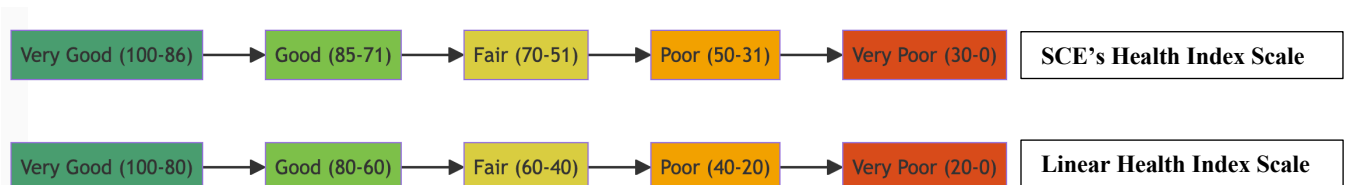
	Average Cost (SCE)	Average Cost (TURN)	% difference
220-500kV	1,077,525	1,057,671	-2%
2.4 - 115kV	363,565	249,833	-46%

TURN proposes using actual costs, by CB voltage levels, to calculate program forecasts – rather than averaging across two broader categories as shown above, and as used by SCE.

### 3.1.4 SCE’s non-linear Health Index may over-estimate “Poor” and/or “Very poor” Equipment:

SCE states that: “...SCE uses the asset health coupled with operational considerations to inform scope selection for each year...” SCE’s Health Index, shown in Table V-22, is a non-linear scale that ranges from “Very Good” to “Very Poor,” with numerical values assigned to each category (100-86 for Very Good, 85-71 for Good, 70-51 for Fair, 50-31 for Poor, and 30-0 for Very Poor).

The Health Index for circuit breakers integrates a range of factors—sulfur hexafluoride gas purity for CBs with SF<sub>6</sub> gas as arc quenching medium, oil circuit breaker analysis for oil CBs, operational frequency, contact resistance tests, and overstress percentages—each with a designated “confidence percentage” reflecting their influence on equipment degradation (these percentages for CBs add to 175%, instead of 100% as one would expect for a weighted scoring rubric). Additionally, subjective assessments like expert evaluations (30%) and Weibull models with questionable assumptions, are factored into the final health score, without their specific weights towards the Health Index score.



SCE’s scale may overstate the number of circuit breakers in poorer condition categories due to its uneven weighting. Adopting a linear scale, which evenly divides CB scores into quintiles, would provide a more balanced categorization. This shift would likely result in fewer circuit breakers being classified as “Poor” or “Very Poor”, offering a more balanced view of asset health. The following bar chart shows distribution of CBs across SCE’s Health Index over time, showing “Poor” and “Very poor” equipment remaining relatively high despite previous infrastructure replacement activities.

### 3.1.5 SCE’s Health Index lacks an empirical basis for scoring:

The absence of consistent health assessment data for SCE's circuit breaker inventory (12,700 according to SCE), which is disputed in size<sup>38</sup>, complicates validation of the health index, rendering any analysis uncertain and akin to tracking a moving target due to progressively increasing number of CBs with Health Index data available as shown.

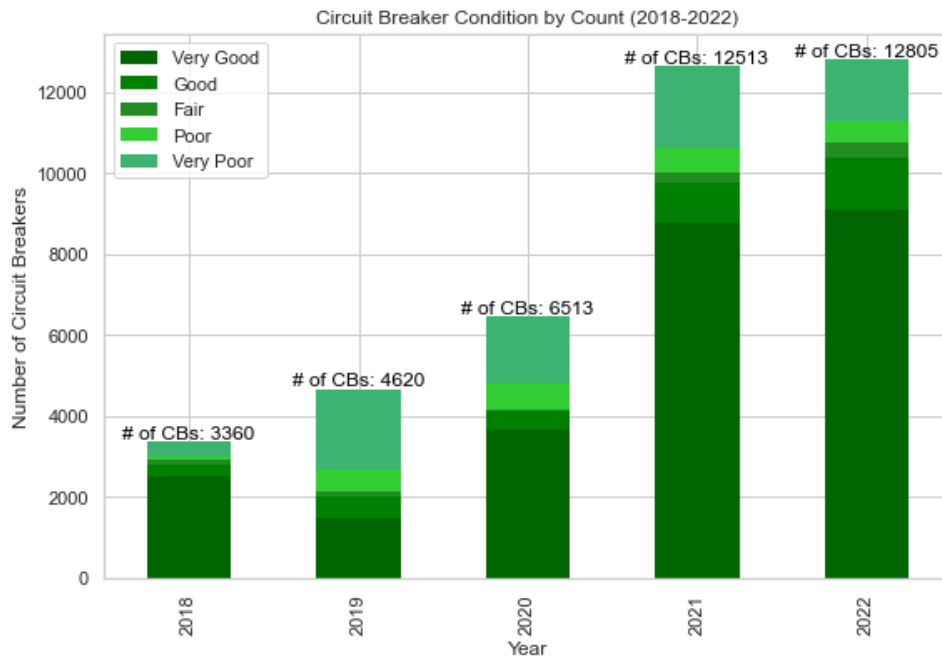


Figure 9 Circuit Breaker Health Index data (2018-2022)

SCE fails to provide a scoring or a scoring rubric to provide an empirical basis for its Health Index score, or historical data suggesting that SCE’s ”Poor” or “Very poor” classifications

<sup>38</sup> Approximately 17,000 based on SAP data received vide SCE-TURN-043 see Fig. below

warrant immediate equipment replacement. An example of such a showing would be a demonstration that equipment classified as “Very poor” historically showed a higher failure rate. The ‘replacement rate’ that SCE uses in its Weibull reliability analysis (contested in the next section) is *not* such a showing.

SCE's Health Index is questionable as it allocates half the scale to “Poor” or “Very poor” without disclosing the scoring distribution or empirical evidence for such weighting. This opacity raises concerns about the index's predictive validity for equipment failure and the justification for replacement decisions.

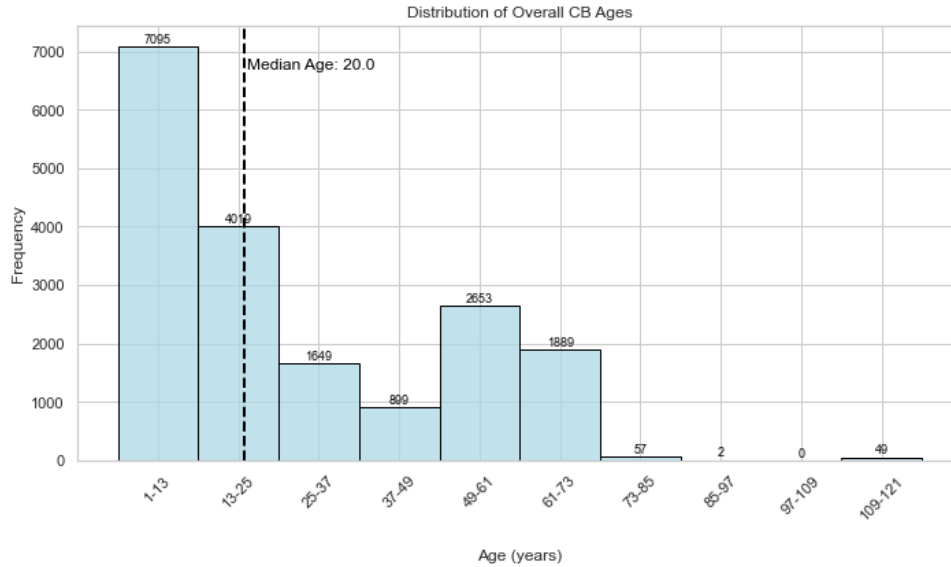
### 3.1.6 SCE’s Scope / Rate Determination for CB Replacement is likely exaggerated:

Historical and proposed replacement of CBs shows that CB health condition data in Table V-22 is not uniformly considered in replacement. In fact, recorded and forecasted installations show CBs in the ‘Very Good’ to ‘Fair’ health condition being replaced without any justification. For example, 44 historical and 109 proposed installations were found to be in “Very Good”, “Good”, or “Fair” condition – undermining SCE’s reliance on health condition of CBs for replacement.

As mentioned before, SCE estimates approximately 2000 CBs in Poor or Very Poor condition as follows:

***Table V-22***  
***Circuit Breakers by Health Condition***  
***as of 2022 Year End***

Equipment	Very Good	Good	Fair	Poor	Very Poor	Total
Circuit Breaker	9,115	1,246	354	568	1,522	12,805



Of these, 4-16kV, 33kV and 66kV CBs seem to be of the most concern, due to number of CBs and relatively high median age (see Appendix 3a). TURN acknowledges that age is an important factor, albeit not the only factor, to determine Health Index.

Moreover, CBs categorized as "Poor" or "Very poor" have been 31% of the total installed CBs (2018-2021 average), and have fallen down to 16% of total in 2022.<sup>39</sup> With (forecast) replacement of "Poor" and "Very poor" CBs in 2023 and 2024, the number of CBs in "Poor" and "Very poor" condition will go down even below the current 16% levels.

### 3.1.7 SCE's Weibull reliability model results are unreliable:

Reliability engineering uses various distributions including the Weibull distribution (and others such as log, gamma, exponential) which is a two-parameter distribution frequently used in reliability analysis. The results of a reliability analysis are contingent on underlying assumptions. SCE uses the following problematic assumptions in its model:

- 1) Use of "replaced" equipment data instead of "failed" equipment warrants interpreting Weibull model outputs as historical Mean Time Before Replacement<sup>40</sup> and not Mean

<sup>39</sup> TURN-SCE-043.Q2.b

Time Before Failure (MTBF). SCE uses an asset “age” variable to predict various parameters using the Weibull distribution. This “age” is a variable denoting equipment replaced “for all causes”, and therefore Weibull estimates do not represent “failure rates” but rather “replacement rates” for equipment (which may or may not correspond with in-service failures).

- 2) SCE uses a relatively small 2016-2022 dataset to predict failure rates far out in time i.e. 2023-2034. The sample size that the analysis is predicated on is arbitrarily chosen and may yield unreliable estimates. A thorough analysis would utilize all available data instead of a subset of data, without due justification.<sup>41</sup>
- 3) In response to TURN-SCE-043 Q4, SCE notes that: “...Weibull distribution was selected to model the failure of equipment that tends to fail due to wear and tear and capable of accommodating a wide range of curve shapes with its two parameters...” and further states: “...Other models were not evaluated given the benefits of the Weibull distribution.”<sup>42</sup> These other models such as lognormal or gamma distribution may provide better estimates and should have been compared before choosing Weibull distribution for its analysis.

SCE’s Weibull reliability models use asset “age” to predict so-called “failure rates” of equipment. This may be misleading since SCE results show “replacement rates”, and not “failure rates”. It remains questionable whether these replacement rates are prudent or not, since they depend on when the equipment was replaced, and not whether or when the equipment had an in-service failure (catastrophic or otherwise).

### 3.1.8 SCE’s Analysis suggests only Oil and Air Magnetic Circuit Breakers may be the best candidates for replacement:

Even based on SCE’s likely exaggerated replacement rates using the Weibull analysis, only air / magnetic or oil-based circuit breakers may be the best candidates for replacement, based on median age of installed fleet of all existing circuit breakers.

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<sup>41</sup> TURN acknowledges that SCE suggests a balance between ‘recency and sample size’ (TURN-SCE-043), but questions the basis of arriving at 2016-2022 as achieving the right balance.

<sup>42</sup> TURN-SCE-043 Q4.b

CB Type	Sample Size (n)	Predicted Mean Time To Failure (or Replacement Age) (SCE)	Median Age of Installed CBs (TURN)
Gas	546	23.88	16.0
Vac	486	28.66	10.0
Oil	1877	53.73	59.0
Air / Magnetic	90	53.43	59.0

\*entries in red may be the only ones that need to be targeted due to relatively higher age

TURN’s contention is that modeled mean time to failure for each CB type should be evaluated against Original Equipment Manufacturer (OEM) recommended mean time to failure to identify variation in observed vs. OEM-suggested failure rates. In response to TURN’s DR, SCE suggested that: “...To SCE’s knowledge, manufacturers typically do not provide a recommendation for a MTTR, MTBF or EUL parameters. SCE typically provides the appropriate design standard for expected design life to the OEM. According to current industry standards, the design life expectancy for circuit breakers and transformers is 30 years...”

Yet, the following charts show large variance from 30 year end of useful life (EUL) suggested by SCE, implying that this cycle of infrastructure replacement will continue unless the EUL estimates are empirically established based on current, installed equipment age and performance status. While this is not in-scope for TURN’s testimony, the currently authorized depreciation life for distribution station equipment (i.e. 65 years), provides an additional data point to challenge the 30 year EUL provided by SCE.

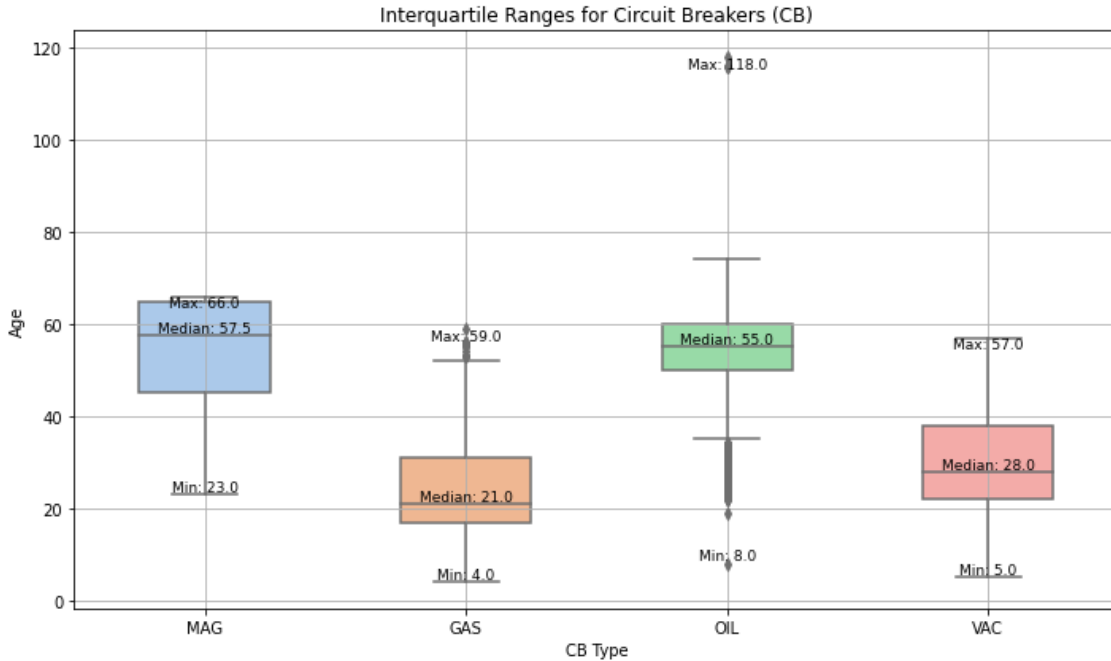


Figure 10 Inter-Quartile Ranges for replaced Circuit Breakers with labeled 50<sup>th</sup> percentile values

**TURN’s Recommendations (Detailed):**

- **Based on our review, TURN proposes to replace CBs in “Poor” and “Very poor” condition per SCE’s Health Index of 1088 CBs from 2023-2028 at an average annual rate of 181 CBs per year – as opposed to SCE’s proposed 1197 CB replacement at 200 replacements per year.<sup>43</sup> The proposed replacement results in an authorized program cost of \$294.7m (Nominal) compared to SCE’s estimated forecast of \$325.9m (Nominal) from 2023-2028.**
- **TURN proposes to exclude all CBs in “Very Good” to “Fair” condition for this GRC.**
  - o SCE should refine its replacement strategy to exclusively target circuit breakers in “Poor” or “Very poor” condition, as per revised Health Index. This approach

<sup>43</sup> This translates to 607 CBs in 2025 GRC Period (2025-2028) at an average annual rate of 152 CBs per year – as opposed to SCE’s proposed 680 CB replacement at 170 replacements per year.

aligns replacements with actual equipment health rather than indiscriminately including CBs rated 'Very Good' to 'Fair,' ensuring resource allocation is both prudent and justified.

- SCE should be directed to explain variation in number of CBs replaced vs. costs incurred. Such showing would include the precise voltage class of CBs forecasted replacements by costs incurred vs. actual replacements done by costs incurred.
  - o Related to above, unit cost analysis needs to be confirmed / re-done. Moreover, SCE should detail the precise voltage classes, such as 4 - 16 kV, 33 kV, 66 kV, 115 kV, 220 kV, 13.8 kV, and 500 kV, for their circuit breaker forecasts for accuracy and transparency, instead of voltage class by two broad categories.
- SCE must substantiate the accuracy of its non-linear health index by providing evidence of correct predictions—where equipment deemed likely to fail did indeed fail—using a clear true versus false positive analysis. This applies to other sections of testimony where the Health Index scale is used.
  - o SCE's Health Index, used to determine the condition of circuit breakers, disproportionately assigns half its scale to “Poor” or “Very poor”. For a more accurate reflection of equipment conditions and to guide replacement decisions effectively, SCE should revise its Health Index to distribute scoring more evenly across categories (as quintiles) and provide transparent, empirical evidence for the weightings and classifications behind the Health Index scale.
- Given the variance in median age for installed CBs, for the next GRC, we propose instituting a strict cutoff for CB replacement based on age, beyond which specific details necessitating replacement must be shared. While TURN does not have a specific suggestion for an age-based cutoff, we suggest developing a replacement approach that incorporates an age-based cutoff.
- SCE's reliance on Weibull models for justifying equipment replacements should be disregarded for forecasting purposes due to its conflation of replacement rates with actual failure rates and the questionable validity of its underlying assumptions.

### 3.2 Substation Transformer Bank Replacement Program:

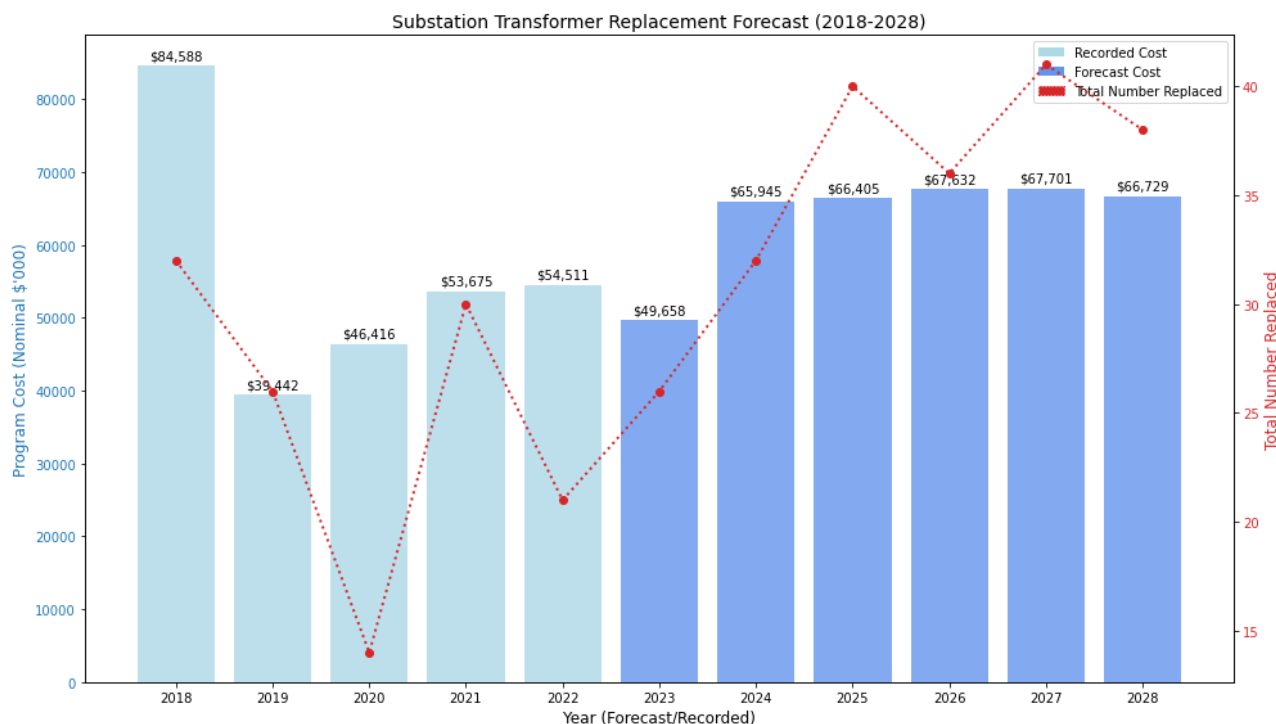


Figure 11 Recorded and Forecasted Costs for Substation Transformer Bank Replacement Program vs. Number of Transformers replaced.

#### 3.2.1 TURN’s Recommendation:

TURN recommends that the Commission should implement an age-based cutoff policy for the capital replacement of transformers, similar to that used for overhead cables. For the 2025-2028 GRC period, it is recommended to approve the replacement of 94 substation transformer banks categorized as “Poor” and “Very poor”, and to reject the replacement of 62 in 'Good' or 'Fair' condition. This adjustment would result in a total of 151 transformer replacements (2 A-Bank, and 149 B-Bank) from 2023-2028, compared to the 213 (5 A-Bank and 208 B-Bank) proposed by SCE. Consistent with these recommendations, the Commission should adopt TURN’s forecast of \$262,896m (Nominal) for the 2023-2028 period instead of SCE’s projected \$385,070m (Nominal). TURN further

**calls for a clear and detailed methodology for calculating unit costs, and propose using exact voltage classes for CPUC-jurisdictional A and B-bank transformers, to enhance forecast precision and transparency.**

### 3.2.2 Analysis of Substation Transformer Bank Replacement Program:

All prior issues highlighted in the discussion of CB replacement persist in substation transformer bank replacement program, summarized below:

<b>Substation Transformer Bank Replacement Program</b>	<b>Explanation</b>	<b>Reference</b>
Exaggerated Safety / Reliability Risks	23 power transformer failures in 13 years, equaling 1.7 failures per year. Again, TURN does not suggest a run-to-failure strategy, but more prudence in allocating costs for replacement.	Pg. 138
Unit Costs	SCE’s ‘Transformer Avg Cost Calc’ tab does not contain any data, making an assessment of a reasonable unit cost impossible. TURN uses SCE’s unit cost numbers to reevaluate Program Forecast.	WP SCE-02, Vol. 05_CB and Transformer Cost Forecast
Non-linear Health Index	Non-linear health index likely exaggerates number (275) of “Poor” and “Very poor” condition transformers. SCE asserts that: “...The lower the health index, the higher probability of failure”, but fails to empirically justify this assumed relationship.	Pg. 139, Table V-19
SCE’s scope / rate of replacement	SCE forecasts replacing 213 substation power transformers from 2023 to 2028, of which 155 are for the 2025 GRC period (at the rate of 39 each year from 2025-2028). Importantly, SCE does not discount for high MVA transformers replacing potentially multiple power transformers as evidenced in 2021. In 2021, SCE incurred \$34.038 m less than the authorized amount of \$87.713 m for the Substation Transformer Bank Replacement Program. This variance was driven by SCE’s ability to replace 13 power transformers with	Pg. 137, 140

	four (4) three-phase power transformers. SCE sought to reduce material, installation, and maintenance costs while addressing space constraints within a substation footprint.	
Weibull Reliability Analysis	Weibull-based Mean-Time-To-Failure for A-Bank and B-Bank transformers is 30.5 years, likely an over-estimate, given Age for ‘Line Transformers’ is 33 years and average age of survivors 10.7 years.	TURN-SCE-043-Q04-Revised Weibull Analysis-TRF  TURN-SCE-002 (Rate Determination Schedule)

For Weibull analysis, the median age of transformers historically replaced “for all causes” is 31 years, with a large variation (0-90+ years) as shown below:

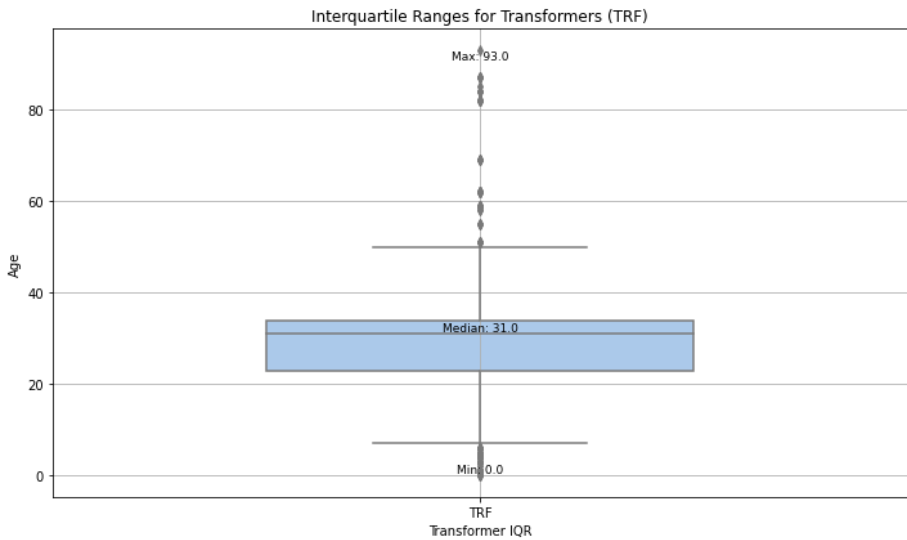


Figure 12 Inter-Quartile Range (IQR) for replaced transformers from SCE’s Weibull Reliability analysis

Literature on power transformer failure analysis suggests that in order to observe a large number of failures per year a much larger power transformer fleet is required than is often owned by one

utility<sup>44</sup>. TURN’s analysis suggests A-Bank and B-Bank transformers have a median age of 12 and 24 years respectively – and therefore generally not old (see Appendix 4a). Again, TURN finds that the total forecasted installations (n=298) per data provided by SCE for 2023-2028 replacements includes a large number (n=94) of Transformers in ‘Fair’ and/or ‘Good’ condition, even according to the company’s non-linear scale which exaggerates ”Poor” or “Very poor” counts as shown below<sup>45</sup>:

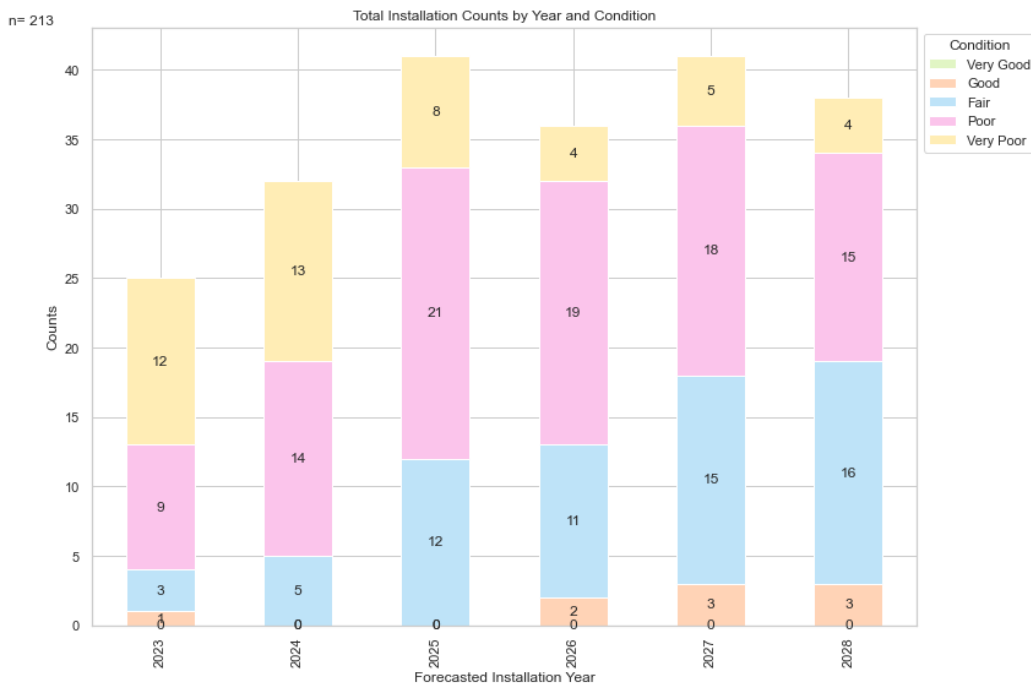


Figure 13 Total Installation counts forecast (n=213) by year and health status

**TURN’s recommendations (Detailed):**

TURN provides the following recommendations:

<sup>44</sup> <https://ieeexplore.ieee.org/abstract/document/8316925>

<sup>45</sup> Note that forecast for CBs based on TURN-SCE-043 from 2023-2028 is 213 replacements, vs. 231 in application.

- The Commission adopt an age-based cutoff (like overhead cable) for capital replacement of transformers.
- For 2025-2028 GRC period, the Commission allow 94 substation transformer banks to be replaced in the “Poor” and “Very poor” categories and disallow 62 substation transformer banks proposed to be replaced in ‘Good’ and / or ‘Fair’ condition. This would result in 151 (2 A-Bank, and 149 B-Bank) total transformer replacements from 2023-2028 compared with 213 (5 A-Bank and 207 B-Bank) as proposed by SCE.
- Data and detailed methodology for calculating unit costs, and use of more precise voltage classes for CPUC-jurisdictional A and B-bank transformers as opposed to the broader A and B-bank transformer distinction, to enhance forecast precision and transparency.
- Following capital program forecast be adopted:

Forecast Year	Inflation Index	AA	A	B	Total	Program Forecast (SCE)	Program Forecast (corrected by TURN)	A	B	Total	Program Forecast (proposed by TURN)	% difference (corrected by TURN)	% difference (proposed by TURN)
2023		1	1	24	26	\$ 49,658	\$ 46,017	1	24	25	\$ 46,017	-8%	-8%
2024	1.082	0	1	31	32	\$ 65,945	\$ 57,859	1	31	32	\$ 57,859	-14%	-14%
2025	1.104	0	0	40	40	\$ 66,405	\$ 67,668	0	29	29	\$ 49,060	2%	-35%
2026	1.114	0	2	34	36	\$ 67,632	\$ 68,351	0	23	23	\$ 38,909	1%	-74%
2027	1.124	0	0	41	41	\$ 67,701	\$ 69,360	0	23	23	\$ 38,909	2%	-74%
2028	1.139	0	1	37	38	\$ 66,729	\$ 68,010	0	19	19	\$ 32,142	2%	-108%
<b>Total</b>			<b>5</b>	<b>207</b>	<b>213</b>	<b>\$ 384,070</b>	<b>\$ 377,266</b>	<b>2</b>	<b>149</b>	<b>151</b>	<b>\$ 262,898</b>	<b>-2%</b>	<b>-46%</b>

Program Forecast (corrected by TURN) uses the same Total Number of A and B bank transformers and average costs as originally proposed by SCE but corrects the unit cost calculation used by SCE.

Program Forecast (proposed by TURN) uses “Very poor” and “Poor” health index assets for the GRC period (2025-2028), proposing to reduce SCE’s proposed number of total replacements from 213 to 151 for 2025-2028. TURN does not contest 2023-’24 forecasts at this time.

#### **4. SCE-02 Vol. 01 Pt. 02: Distribution Infrastructure Replacement**

SCE describes Distribution Infrastructure Replacement (DIR) as a continuous and necessary process involving the renewal and upgrading of fundamental components of the electricity distribution system, such as poles, transformers, switches, capacitors, automatic reclosers, cable, and conductors<sup>46</sup>. TURN acknowledges the necessity of evidence-informed infrastructure replacement (IR) to ensure a safe and reliable electricity grid, and in no way advocates for a run-to-failure approach (except, as demonstrated to be prudent<sup>47</sup>). TURN further recognizes the historical reduction in IR activities, as detailed in the 2021 General Rate Case (GRC) findings of fact.<sup>48</sup>

However, while the need for infrastructure replacement is recognized, the approach to such investments should not be an overcorrection that incurs excessive capital expense without thorough review of the reasonableness of that approach. This is especially critical for regular infrastructure work that is unrelated to wildfire safety. We find that the proposed costs for cable / conductor replacement programs show significant increases, even when compared to costs for similar programs prior to the 2021 GRC period as shown below:

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<sup>46</sup> SCE-02, Vol. 1, Pt. 2, pg. 4 (lines 4-6)

<sup>47</sup> See footnote 18 in SCE-01, Vol. 1, pg. 11

<sup>48</sup> GRC 2021 Decision (Finding of Fact: #33)

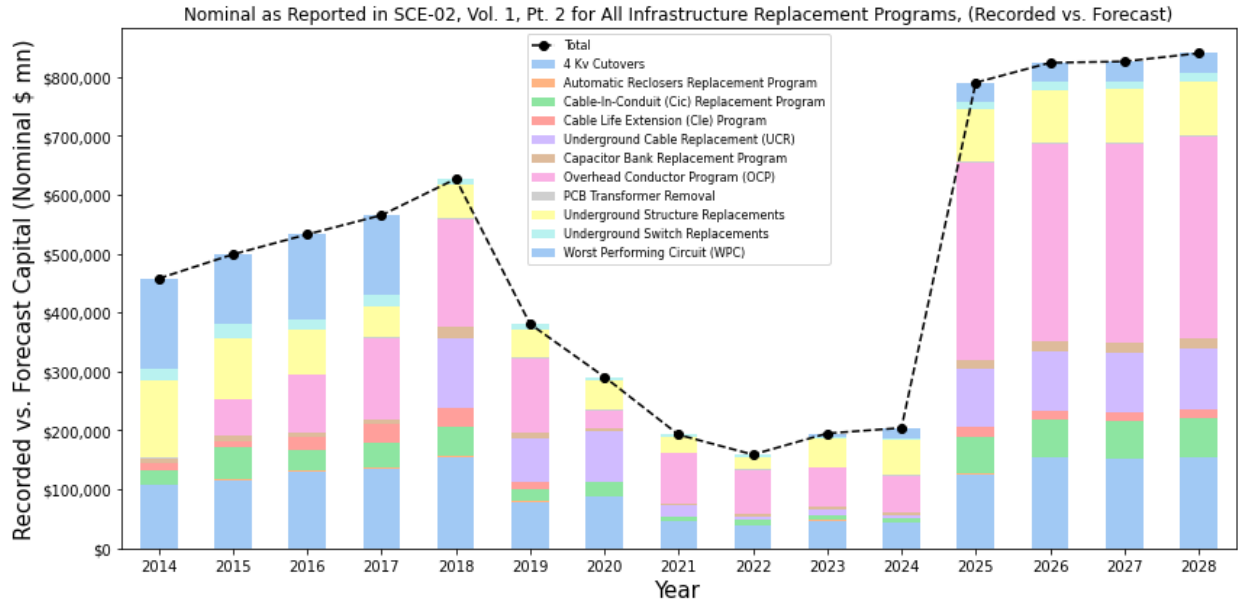


Figure 14 Nominal program costs (Recorded 2014-2022 vs. Forecasted 2023-2028) for all Distribution Infrastructure Replacement programs.

#### 4.1 Assessment of SCE's Cable and Conductor Replacement Financial Forecasts:

Of the above Distribution Infrastructure Replacement programs, five programs relate specifically to underground or overhead cable replacement programs. TURN finds a lack of discussion on the synergies between various cable / conductor replacement programs in terms of safety and reliability risk reduction, and how that is factored in the proposed program forecasts.

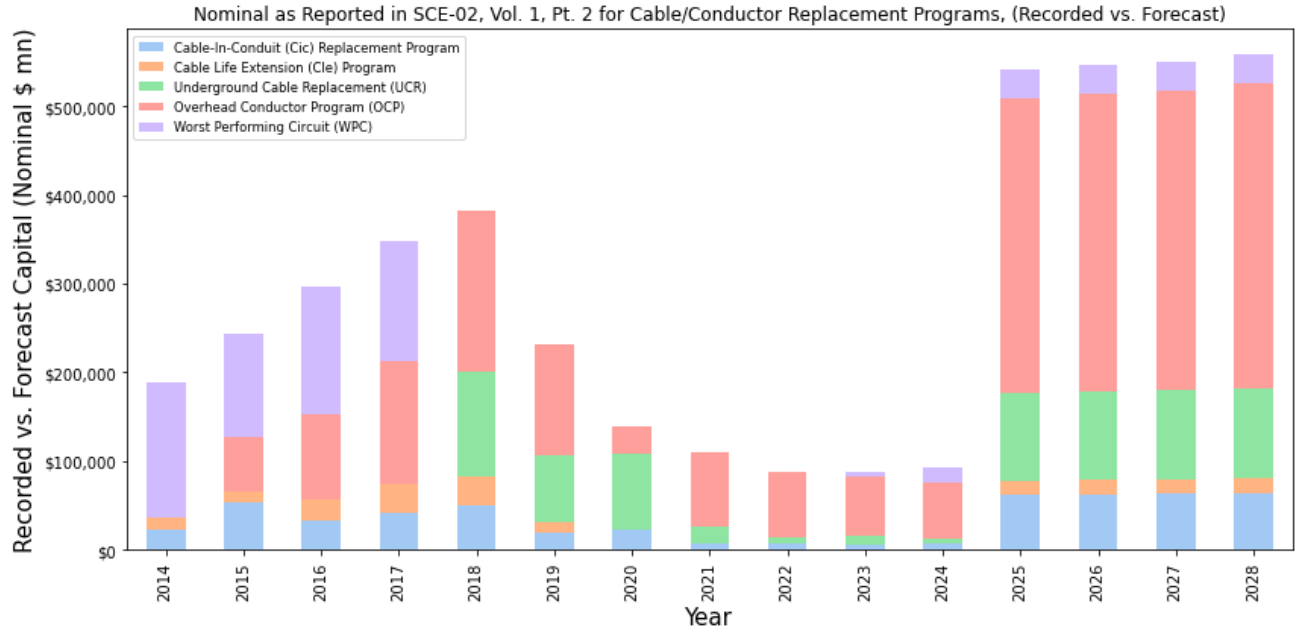


Figure 15 Nominal program costs (Recorded 2014-2022 vs. Forecasted 2023-2028) for all Cable/Conductor Replacement programs.

GRC Activity (Cable/Conductor related)	Program Recorded Cost (2017-2022 Total, Nominal \$)	Program Forecast Cost (2023-2028 Total, Nominal \$)	% difference
Cable-In-Conduit Replacement Program (CiC)	150,905,465	266,013,011	76%
Cable Life Extension Program (Cle)	74,710,857	64,270,959	-14%
Underground Cable Replacement (UCR)	303,940,826	416,449,890	14%
Overhead Conductor Program (OCP)	634,126,619	1,478,479,159	133%
Worst Performing Circuit (WPC)	135,285,650	154,150,599	14%
Total	1,298,969,416	2,379,363,618	83%

Figure 16 Nominal program costs and percentage change (Recorded 2014-2022 vs. Forecasted 2023-2028) for all Cable/Conductor Replacement programs.

SCE is seeking \$2.379bn (Nominal)<sup>49</sup> in Distribution Capital Infrastructure Replacement Capital Activities (excluding Climate Adaptation and Vulnerability Assessment Distribution Infrastructure Replacement) for 2023-2028, an 83% increase from prior 6 years. SCE’s approach to infrastructure, broadly, rests on two premises: the likelihood of a component failing while in use, and the potential impacts that such a failure could have.<sup>50</sup>

The following three overall arguments for SCE’s unprecedented ~\$2.4bn capital request necessitate a review of these programs and projected safety and reliability benefits:

4.2 Worsening Distribution Side Metrics (SAIDI / SAIFI) may be a direct result of Transmission-Level Reliability:

In discussing its distribution infrastructure replacement drivers<sup>51</sup>, SCE presents safety, service reliability, capacity needs, and aging infrastructure as primary drivers of its distribution infrastructure replacement. In the SCE GRC Workshop Presentation as well as its GRC application, SCE emphasizes its need for massive infrastructure replacement capital expense by showing worsening trends of SAIDI / SAIFI numbers.<sup>52</sup>

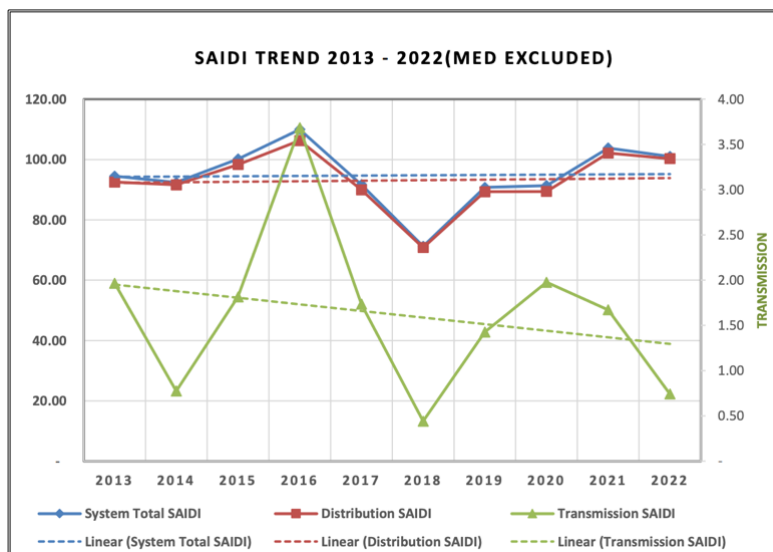


Figure 17 2013-2022 SAIDI trend from SCE's 2022 Annual Reliability Road

TURN finds that, from SCE’s 2022 Annual Reliability Report, these trends may have been a direct causal effect of SAIDI / SAIFI metrics worsening at the Transmission Level, for any number of reasons unrelated to aging distribution infrastructure. In general, based on protection coordination with downstream devices, a fault on the transmission

<sup>49</sup> See tab 8-Calculation-Forecast 23-28 in WP SCE-02, Vol. 01, Pt. 2, Distribution Grid Infrastructure Replacement Alternative Forecast Scenarios

<sup>50</sup> SCE-02, Vol. 1, Part 2, Pg. 5

<sup>51</sup> SCE-02, Vol1, Part 2 - Pg 7

<sup>52</sup> SCE-02, Vol1, Part 2 - Fig. II-2, II-3 on pg. 10

level may isolate circuits at the distribution level to avoid a cascading failure. As discussed in the following sections, these SAIDI / SAIFI metrics may also be caused by vegetation, source loss, 3<sup>rd</sup> party etc. On the contrary, a fault on the distribution feeder that could potentially signal failing distribution assets, will not trip an upstream transmission device. As H. Eto et al. (2019) from Lawrence Berkeley National Laboratory report: "...the most basic and widely reported measures of continuity of service [i.e. SAIDI / SAIFI] in the US cannot, in their present form, be used meaningfully to assess or prioritise efforts to improve the distribution versus bulk power system reliability because they mask the source of power interruptions..."<sup>53</sup> Moreover, as shown in the following section, reliability metrics (SAIDI / SAIFI) for overhead conductor / splice / connector / tap have been improving, thanks to prior ratepayer funded programs.

#### 4.3 SCE's Steady-State Replacement Rate argument lacks supporting data:

SCE posits a theory of steady-state replacement rate<sup>54</sup> to justify its infrastructure replacement expenditures. This theory suggests that equipment failure rates follow a curve that is initially low but increases with age and wear. SCE presents this curve to argue for the necessity of replacing aging infrastructure to maintain system reliability and safety.

While the theory of equipment following a predictable failure curve is generally accepted, SCE has not provided concrete data on replacement rates over any time horizon, rendering its curve theoretical and the application of a long-term steady state replacement rate in planning decisions speculative at best.

In TURN's DR regarding data on steady-state replacement rates for SCE-02, Vol. 4<sup>55</sup>, SCE sidesteps TURN's inquiry regarding data on current and historical replacement rates, suggesting that the request was "unduly burdensome". While SCE's theoretical model of steady-state replacement rates—which predicts an increasing fraction of components reaching the end of their service life over time—is conceptually valid, the utility's lack of detailed, asset-level historical

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<sup>53</sup> [https://eta-publications.lbl.gov/sites/default/files/dist\\_system\\_vs\\_bulk\\_power\\_journal\\_article.pdf](https://eta-publications.lbl.gov/sites/default/files/dist_system_vs_bulk_power_journal_article.pdf)

<sup>54</sup> SCE-02, Vol. 1, Part 2, Pg. 11,12

<sup>55</sup> TURN-SCE-053 Q06.a-b

replacement rate data undermines the practical application of this model. In fact, in its rebuttal arguments in the 2021 GRC, SCE argued that attempting to calculate a steady-state replacement rate for IR planning purposes is fundamentally a “practical impossibility”<sup>56</sup>.

TURN's request for concrete data on replacement rates is aimed at grounding this theory in observable trends, and enabling an objective analysis of infrastructure replacement rates, their trajectory, and whether it is practical to reach a “long-term steady-state replacement rate”, given affordability concerns. Moreover, access to such data could also help refine the accuracy of predictive models like the Weibull Reliability model, leading to risk-informed decision-making strategies for maintaining system reliability and safety, at reasonable costs.

#### 4.4 Probing the accuracy of SCE’s Predictive Models:

In the wake of SCE’s substantial \$3.6bn capital request for distribution infrastructure replacement, a critical examination of the underlying arguments and methodologies, particularly those related to predictive modeling, is essential.

TURN, aligned with the Safety and Policy Division (SPD) recommendation in its Staff Evaluation Report of SCE’s 2022 RAMP, acknowledges the potential of machine learning (ML) models for predictive maintenance but raises concerns about their transparency.<sup>57</sup> We emphasize the opacity of SCE’s ML models, which, despite their sophistication, remain largely inscrutable. The noting of this lack of clarity is not to suggest that SCE’s use of ML is unreasonable *per se*, but rather an emphasis on the need for greater transparency in the algorithms and data that feed into these predictive models. Establishing the effectiveness of these models, such as the Random Forest used in SCE’s Overhead Conductor Program (OCP) and Accelerated Overhead Conductor Program (AOCP), is crucial, especially when considering the safety implications and the financial burden the outcomes could place on ratepayers. The utility must mitigate information asymmetries and provide stakeholders with the means to understand and verify the models. For instance, SCE’s reliance on the Random Forest model necessitates disclosure of the training data,

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<sup>56</sup> D21-08-036 – pg. 44

<sup>57</sup> [https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/sce-2022-ramp-evaluation-report-final\\_111022.pdf](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/sce-2022-ramp-evaluation-report-final_111022.pdf)

assumptions, and statistical validity measures. Without these, the black-box nature of ML models remains a barrier to accountability and trust.

#### **4.1.1 Overhead Conductor Program (OCP):**

The IR activities under SCE’s overhead distribution system include the Overhead Conductor Program (OCP), Distribution Overhead Switch Replacement Program, and Overhead Capacitor Replacement Program. The Overhead Conductor Program (OCP), initiated in SCE's 2018 General Rate Case (GRC), primarily aims to mitigate public safety and reliability risks from energized downed overhead conductors. Starting in 2025, SCE proposes a shift from using bare wire to covered conductors based on “the drivers of conductor failure events”<sup>58</sup>, proposing to replace 1,680 miles (small and big gauge wires) at a pace of 420 miles per year from 2025-2028. SCE states in its scope forecast that: “...SCE currently maintains and operates approximately 30,000 circuit miles of primary overhead conductor outside of HFRA and in HFRA locations where WCCP is not prioritizing reconductoring of overhead lines...”<sup>59</sup>

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<sup>58</sup> SCE-02, Vol. 1, Pt. 2 (lines 8,9)

<sup>59</sup> SCE-02, Vol. 1, Pt. 2 (lines 22-24)

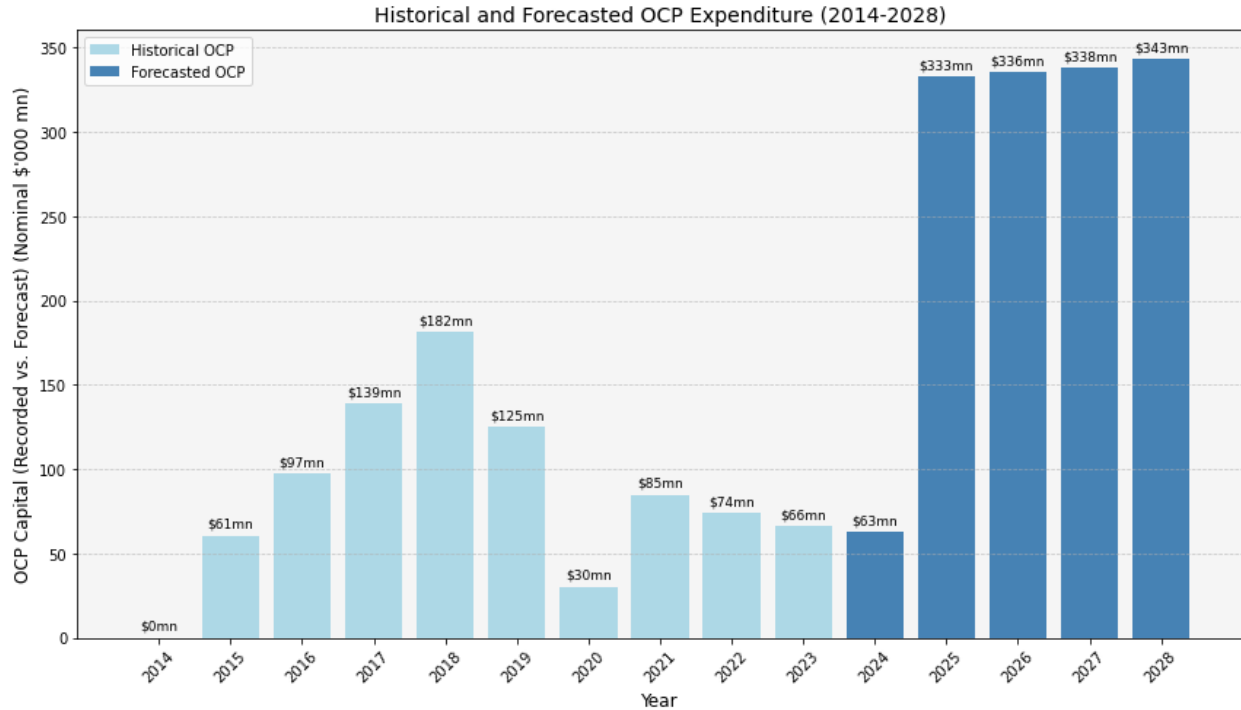


Figure 18 Nominal program costs (Recorded 2014-2022 vs. Forecasted 2023-2028) for Overhead Conductor Program (OCP).<sup>60</sup>

OCP had a budget over-run of \$12m (nominal) based on 2021 authorized vs. recorded capital expenses.<sup>61</sup> In the 2021 General Rate Case (GRC) Decision, it was established that SCE's implementation of 3,750 circuit miles of covered conductor is the most extensive among California Investor-Owned Utilities. Moreover, the Decision noted SCE's insufficient explanation of the Public Safety Power Shutoff (PSPS) benefits resulting from this deployment. Despite the significant installation, risks of utility-caused ignitions persist even in areas with covered conductors.<sup>62</sup>

#### 4.1.2 TURN's Recommendation:

**TURN recommends rejecting SCE's entire proposed Overhead Conductor Program (OCP), except the Accelerated Overhead Conductor Program (AOCP). SCE's proposed spending level, exceeding \$330 million annually from 2025 to 2028, will be unduly**

<sup>60</sup> WP SCE-02, Vol. 01, Pt. 2, Distribution Grid Infrastructure Replacement Alternative Forecast Scenarios

<sup>61</sup> SCE-02, Vol. 1, Pt. 2 (Fig. II-8)

<sup>62</sup> 2021 GRC Decision (Findings of Fact: #250, #254, #257)

**burdensome and, in all likelihood, not achieve the projected safety and reliability benefits. In case the entire program is not rejected, we propose approving only small-gauge wire replacements (~634 miles) within the OCP due to their higher failure probability. We further recommend rejecting SCE’s planned replacements using bare conductors—117 miles in 2023 and 91 miles in 2024—based on SCE’s own showing of reduced bare conductor benefits. While we acknowledge the safety risks of energized wire-down events, TURN points to SCE’s admission of not tracking Serious Injury and Fatality (SIF) data by circuit segment, which casts doubt on the effectiveness of the ML model-based segments in reducing SIF or potential SIF incidents. TURN’s proposal recommends authorizing \$396.5m (Nominal) against SCE’s proposal of \$1.4bn (Nominal) for the program.**

		From PubAdv-SCE-140-GAW						
		2023	2024	2025	2026	2027	2028	Total (Nominal \$000)
SCE's Proposal	Bare Conductor (circuit miles)	117	91	-	-	-	-	208
	Bare Conductor Unit Cost (2022\$) (\$000)	\$495	\$495	\$ -	\$ -	\$ -	\$ -	N/A
	Covered Conductor (circuit miles)	-	-	420	420	420	420	1,680
	Covered Conductor Unit Cost (2022\$) (\$000)	\$663	\$663	\$663	\$663	\$663	\$663	N/A
	<b>Subtotal (Nominal \$000)</b>	<b>\$61,009</b>	<b>\$49,602</b>	<b>\$315,704</b>	<b>\$318,370</b>	<b>\$320,596</b>	<b>\$325,262</b>	<b>\$1,390,543</b>
	Accelerated OCP (\$000)	\$5,269	\$13,272	\$13,595	\$13,710	\$13,806	\$14,007	\$73,660
	Escalation	1.054	1.106	1.133	1.143	1.151	1.167	N/A
	<b>Total (Nominal \$000)</b>	<b>\$66,278</b>	<b>\$62,874</b>	<b>\$329,299</b>	<b>\$332,080</b>	<b>\$334,402</b>	<b>\$339,269</b>	<b>\$1,464,203</b>
		2023	2024	2025	2026	2027	2028	Total (Nominal \$000)
TURN's Proposal	Bare Conductor (circuit miles)	0	0	0	0	0	0	0
	Covered Conductor (small gauge, circu	0	0	106	106	106	106	424
	Covered Conductor (\$000)	\$0	\$0	\$79,625	\$80,328	\$80,890	\$82,014	\$ 322,857.13
	Accelerated OCP (\$000)	\$5,269	\$13,272	\$13,595	\$13,710	\$13,806	\$14,007	\$ 73,659.00
	<b>Total (Nominal \$000)</b>	<b>\$5,269</b>	<b>\$13,272</b>	<b>\$93,220</b>	<b>\$94,038</b>	<b>\$94,696</b>	<b>\$96,021</b>	<b>\$396,516</b>

\*TURN’s proposed forecast assumes same unit cost for small gauge covered conductor as SCE’s forecast.

There are several issues with the use of the extensive replacement of OH conductor proposed by SCE that support our recommendations above.

#### 4.1.3 Covered conductor is already being deployed in non-HFRA:

SCE's construction standards permit the use of Covered Conductor beyond High Fire Risk Areas (HFRA) for criteria such as areas prone to tree-to-wire contacts, metallic balloon interference, intermittent contacts causing outages, proximity to the ocean, unguyed spans, and regions with

accelerated corrosion.<sup>63</sup> While proactive programs like WCCP and OCP are in place for systematic replacement, SCE does not have a dedicated forecast for Covered Conductor miles within the 2025 GRC request. However, SCE will consider its use in various capital programs where necessary to improve public safety and reliability, including reactive scenarios like replacing conductors after vehicular accidents. This underscores the broader application of Covered Conductor deployment beyond the substantial capital requested for the Overhead Conductor Program.

#### 4.1.4 Extensive Proposed scope of the program necessitates regulatory scrutiny:

SCE’s proposed program is different from SCE's Wildfire Covered Conductor Program (WCCP) within its Wildfire Mitigation Plan (WMP) and aims to address both a) overhead conductors across SCE’s non-HFRA and b) the part of the HFRA not included in WCCP. SCE defines conductor segments as ‘spans of OH conductor that connect one piece of electrical equipment to another.’<sup>64</sup> “Splice/Connector/Tap” are ancillary equipment that are connected to the OH conductor and would be replaced as part of OCP.

The total population of non-HFRA primary OH conductor eligible for OCP is 30,000 circuit miles or 500,000+ circuit segments. The 2025-2028 OCP scope represents 34,588 OH conductor segments, which equates to 1,680 circuit miles, or ~5% of total eligible circuit miles for OCP. This program, if approved, might thereafter become a recurring ask.

<b>Conductor Segments to Circuit Miles</b>		
<b>Primary OH Distribution Segments</b>	<b>Primary OH Distribution Circuit Miles</b>	<b>Description</b>
700,000+ circuit segments	~40,000 circuit miles	All primary OH Distribution
500,000+ circuit segments	~30,000 non-HFRA circuit miles	Eligible for OCP
	~1500 HFRA miles	

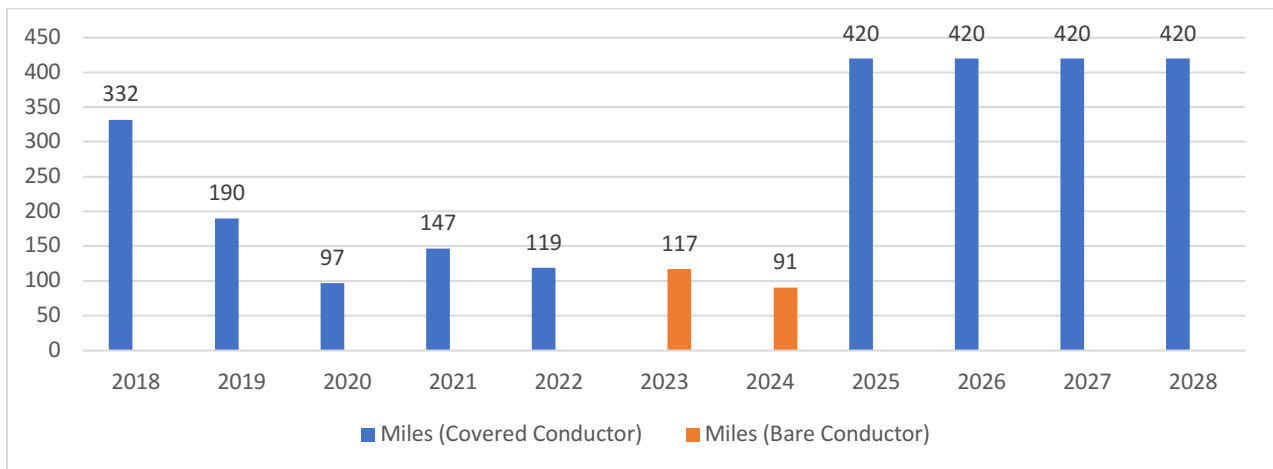
*Figure 19 OCP program scope - Conductor Segment vs. Conductor Miles*

<sup>63</sup> SCE response to PubAdv-SCE-140-GAW

<sup>64</sup> TURN-SCE-072 Q3.a

The Overhead Conductor Program (OCP) shows a percentage increase of 133% in forecast costs for the GRC period (2023-2028) compared to the average recorded costs from prior 6 years.

SCE has not justified its reliance on reconductoring to the exclusion of alternative mitigations. Moreover, despite suggesting the disadvantages of using bare conductor over covered conductor, SCE proposes to replace 117 and 91 miles using bare conductor in 2023 and 2024, respectively.



*Figure 20 Overhead Conductor Program Circuit Miles (2018-2022 recorded vs. 2023-2028 proposed)*

3.1.5 Covered Conductor is one of the costliest mitigation alternatives and therefore appropriate to utilize in very specific use cases:

The application of covered conductors is highly specific and not universally suitable for all environments, as demonstrated by their use in Japan for dense urban safety and in Australia for bushfire mitigation. In contrast, for California's diverse landscapes and increasing electricity demand, the additional weight and reduced ampacity of covered conductors might not present the optimal solution. A few key issues with covered conductor include, in addition to being 1.3 times<sup>65</sup> the cost of bare conductor:

<sup>65</sup> Table II-23

1. For the same conductor size and type, a covered conductor will be approximately 1.54 to 1.89 times heavier, with a 3.1% to 9.1% lower ampacity compared to its bare counterpart<sup>66</sup>.
2. Expected service life used in RSE and other calculations is 45 years, likely an over-estimate compared to 40 years service life recommended by multiple suppliers.<sup>67</sup>
3. Wear and tear may lead to premature insulation breakdown, equating effectiveness to bare conductor in high vegetation, corrosive environments, and/or improper installation.<sup>68</sup>

#### 4.1.6 SCE's Reliability benefits are likely exaggerated based on historical reliability data:

TURN notes that historical reliability of circuit segments / circuit miles targeted by the program has already been improving with existing rate-payer funded programs.<sup>69</sup> SCE states that :  
“...While IR is driven by safety and reliability concerns, it can also provide an opportunity to address capacity to a degree as well...”<sup>70</sup> For capacity, OH conductor would require bigger gauge cable to achieve the same level of capacity due to ampacity difference between bare vs. insulated cable.

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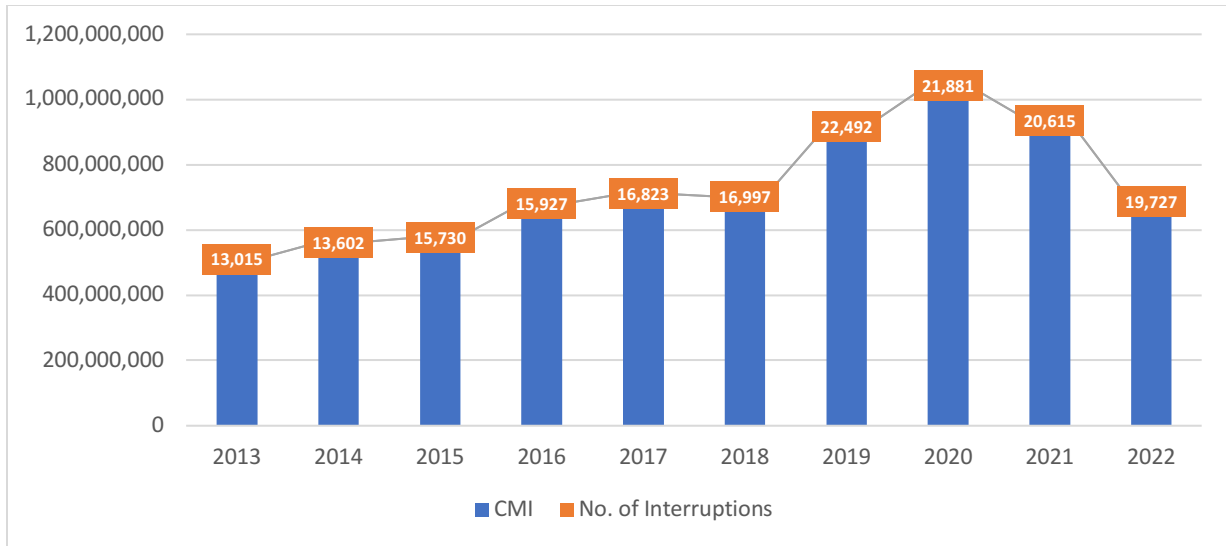
<sup>66</sup> Covered Conductor Compendium, SCE, 2018 (pg. 20-21):  
<https://www.sce.com/sites/default/files/AEM/Supporting%20Documents/2023-2025/Covered%20Conductor%20Compendium.pdf>

<sup>67</sup> Covered Conductor Compendium, SCE, 2018, Pg. 52

<sup>68</sup> Covered Conductor Compendium, SCE, 2018

<sup>69</sup> TURN-SCE-072 Q4.a-b

<sup>70</sup> SCE-02, Vol. 1, Part 2, Pg. 11 (footnote: 16)



*Figure 21 Historical Reliability (No. of Interruptions and CMI) of circuit Miles proposed to be replaced by covered conductor is already improving, thanks to other ratepayer funded mitigation programs.*

As previously mentioned, “Splice/Connector/Tap” are ancillary equipment that are used in conjunction with overhead conductors to make necessary connections to other devices. All these ancillary devices that are connected to the OH conductor would be replaced as part of OCP. “Other OH equipment” could be switches, transformers, capacitor banks.<sup>71</sup> Trends show OH conductor-related SAIDI/SAIFI going down, whereas other equipment-related interruptions are going up, suggesting a focus on “Other OH Equipment”.

<sup>71</sup> TURN-SCE-072 Q5.c

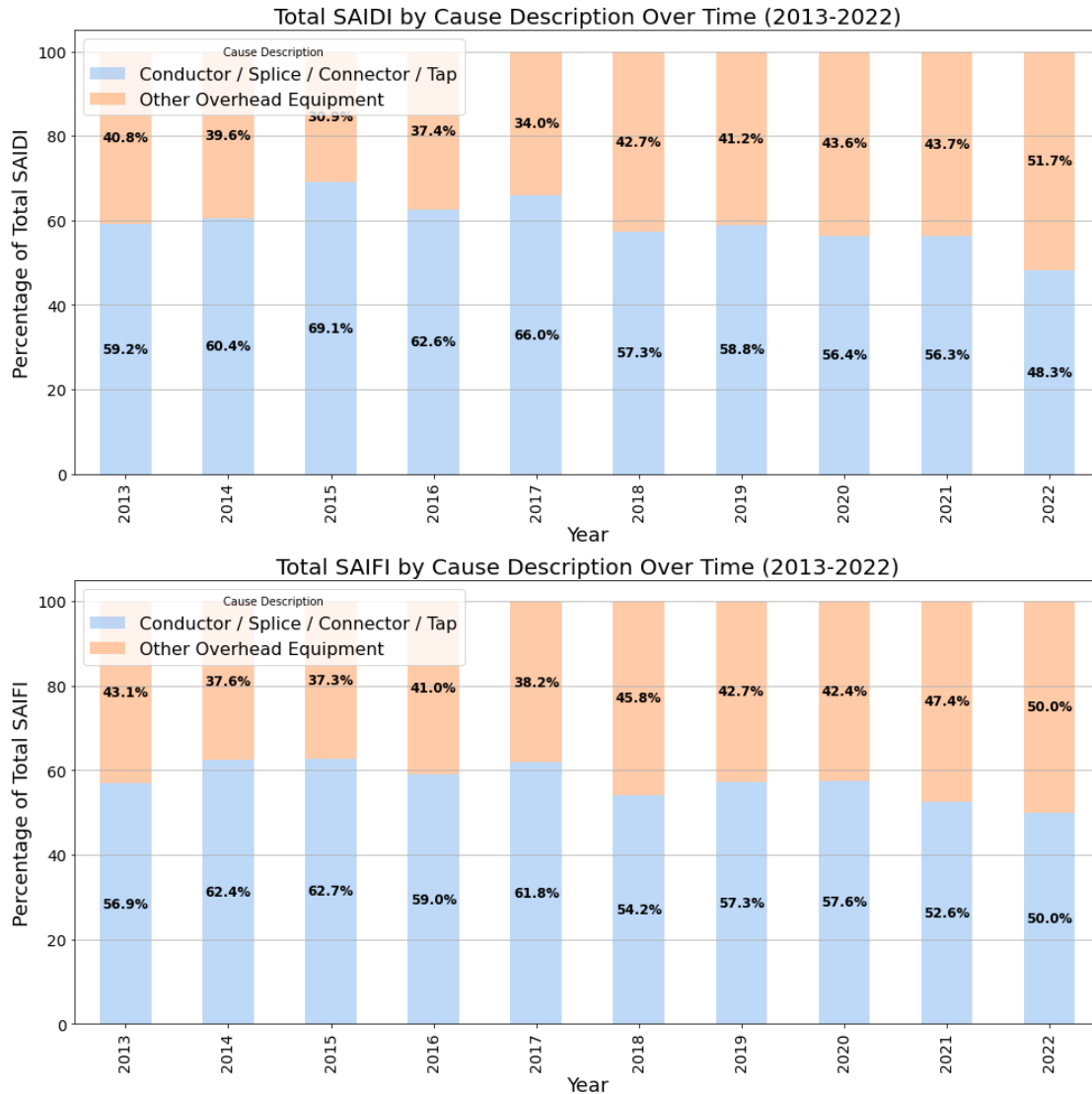


Figure 22 SAIDI / SAIFI Trends for OH Equipment Faults (2013-2022)<sup>72</sup>

TURN has not objected to condition-based replacement of ‘Other OH Equipment’, excluding substation transformer banks, where TURN proposes reduced scope / rate of replacement based on analysis of asset condition.

<sup>72</sup> TURN-SCE-072, Q5.b

4.1.7 SCE’s new program scope includes 1000+ miles of big gauge wires without adequate explanation of safety and/or reliability benefits:

SCE's scope for its Overhead Conductor Program (OCP) has expanded from its RAMP 2022 filing to the General Rate Case (GRC) to include larger gauge wires in addition to the previously targeted small-gauge wires, without an accompanying tranche-level analysis of larger gauge wires and their associated RSE scores. SPD identifies this as its first key observation in its response to SCE’s RSE scoring for the Contact with Energized Equipment (CEE) Risk, stating that “SCE excluded reliability and financial consequences from their calculation of risk scores” and that “SCE’s tranche analysis is not in compliance with the (S-MAP) Settlement Agreement requirement (with respect to the level of granularity expected for the CEE Risk)”.<sup>73</sup>

The OH Conductor model utilized by SCE employs Random Forest, a machine learning technique, to predict the probability of failure for distribution primary overhead conductors predicting 1,680 circuit miles of (small and big gauge) bare conductor to be replaced with covered conductor.<sup>74</sup>

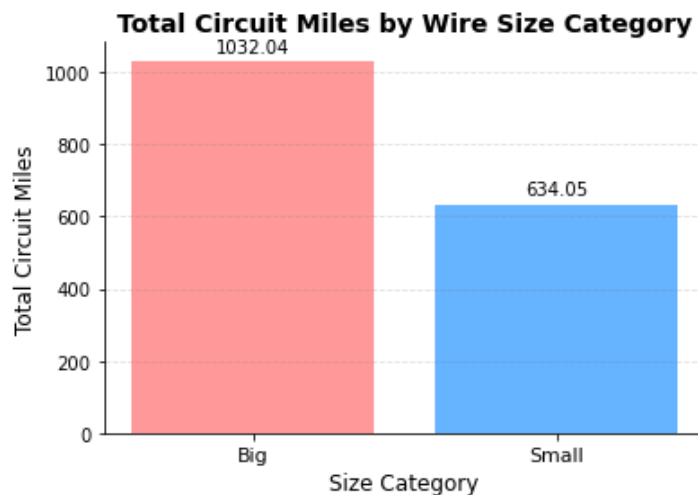


Figure 23 OCP Program Scope (Small vs. Big Wire)<sup>75 76</sup>

<sup>73</sup> Safety Policy Division Staff Evaluation Report on SCE’s 2022 RAMP Application (A.)22-05-013, pg. 42

<sup>74</sup> TURN-SCE-072, Q1.a-b

<sup>75</sup> TURN-SCE-072- Q1.a

<sup>76</sup> Figure includes a discrepancy where TURN calculated results add to 1,666 miles, as opposed to SCE’s 1,680 miles.

TURN argues that covered conductor is only justified for targeted replacement of small gauge wire as reflected from analysis of SCE’s data historical wire-down events below. Covered conductor is ‘effective’ in highlighted categories, per Covered Conductor Compendium, pg. 40, reflecting its efficacy for a limited number of primarily small-gauge wire related outages.<sup>77</sup>

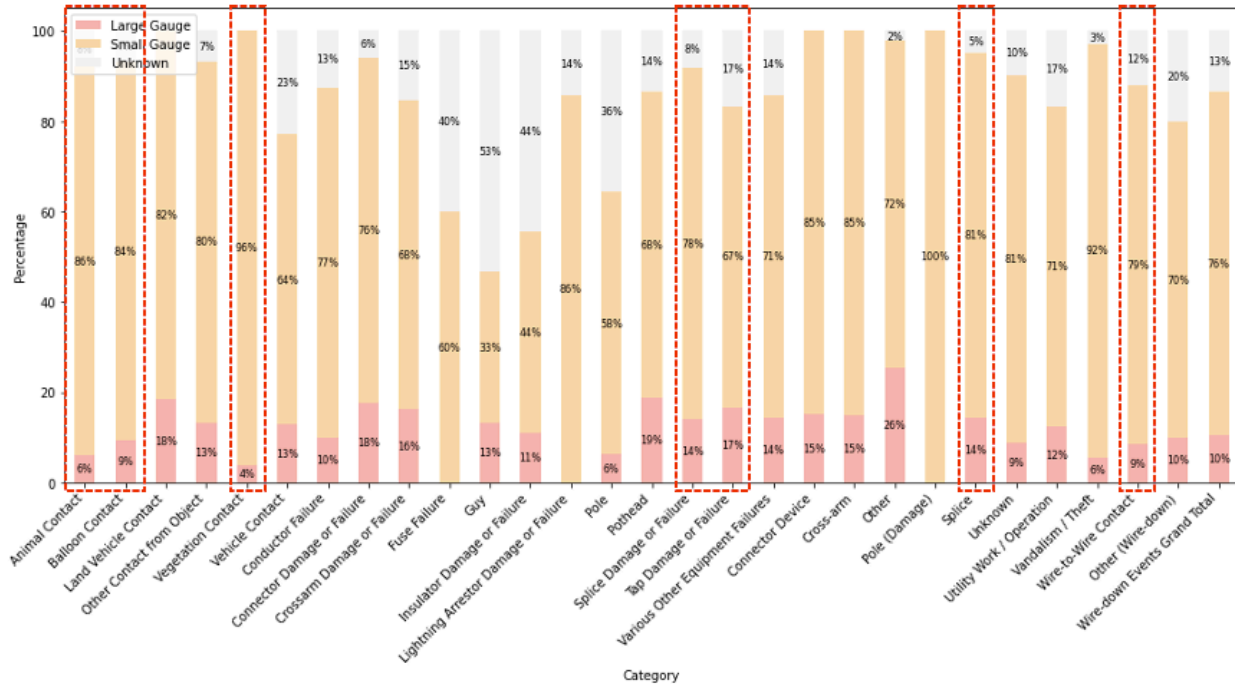


Figure 24 Large / Small / Unknown Gauge – related wire-down events by Primary Driver (2013-2022)<sup>78</sup>

#### 4.1.8 Assessing accuracy of ML-based model prediction for scope and priority determination is challenging without more insight into the modeling process:

The OCP’s scope and prioritization rely on machine learning models to assess failure probabilities and consequences. Additionally, the Accelerated Overhead Conductor Program

<sup>77</sup> <https://www.sce.com/sites/default/files/AEM/Supporting%20Documents/2023-2025/Covered%20Conductor%20Compendium.pdf>

<sup>78</sup> TURN-SCE-072, Q1.a-b

(AOCP) deals with immediate covered conductor replacements after failures, focusing on urgent safety risks and power restoration. SCE states that: "...Previously, the OCP solely focused on addressing public safety risks associated with small-gauge wire. Small-gauge wire has a relatively high probability of failure, leading to greater danger of energized wire-down events..."<sup>79</sup>

SCE's ML model comprises two sub-models: the EFF (Equipment Facility Failure) Conductor, a binary classification model predicting the probability of conductor failure, and the CFO (Contact with Foreign Object), a multi-classification model estimating failure probabilities due to various foreign objects like animals, vegetation, balloons, vehicles, and others.<sup>80</sup> SCE asserts that despite exploring other algorithms such as gradient boosting and neural networks, SCE found no 'significant improvement' in accuracy over the Random Forest model – it remains unclear what the outcomes from other algorithms with improved accuracy turned out to be, and why SCE chose to opt for the RF model. The selection of model algorithms, feature selection, and hyperparameter tuning were guided by two performance metrics: ROC (Receiver Operating Characteristic) and AUC (Area Under the Curve).

There are at least several concerns with SCE's ML approach. Firstly, the Random Forest model's precision in estimating 1,680 miles scope out of the total 31,500 miles eligible for the Overhead Conductor Program (OCP) is not well-supported.<sup>81</sup> SCE does not identify or explain the dataset used to train the model. Secondly, the model presumes that the features used are good indicators of the outcome (probability of failure), overlooking the possibility of unaccounted variables and/or interactions between variables that could lead to mispredictions. Additionally, Random Forest, like many machine learning models, acts as a "black box," where the decision-making process is not entirely transparent, making it challenging to fully understand or trust the model's predictions. Thirdly, SCE provides point estimates for failure probability, without identifying basic statistical measures of model validity such as ranges, confidence intervals or p-values for its final output. Finally, SCE fails to mention how the topmost important features (including

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<sup>79</sup> Pg. 83, lines 1-3

<sup>80</sup> TURN-SCE-072, Q3.a-e

conductor age) explaining wire-down events from the EFF and CFO sub-models are considered in the final determination of 1,680 miles' scope for the program.

This opacity undermines the thorough vetting of the model, as stakeholders cannot easily decipher how decisions are made, and should have been part of the modeling exercise. Other models that might offer better interpretability for binary classification tasks include logistic regression, which, despite its simplicity, provides clear relationships between features (input variables) and the outcome. Decision trees and boosted trees (e.g., XGBoost) also offer a balance between accuracy and interpretability, with mechanisms to understand feature importance and decision paths, which could enhance trust and allow for more straightforward validation of the model's assumptions and predictions. Moreover, comparison of the RF model's performance against other classification models was found missing in the analysis. Another layer of complexity arises when SCE uses the ML model output to determine "remaining risk (%)" after replacing 420 miles per year of conductor from 2025-2028. Finally, this risk percentage reduction is used to estimate expected SAIDI, and a modest average of 3.5 minutes of reduction in outage minutes experienced by customers from 2025-2028 is estimated.<sup>82</sup>

Based on SCE's provided data on risk reduction as a function of Covered Conductor length<sup>83</sup>:

Conductor Length (in miles)	MARS Cumulative Risk	Total MARS Risk	Safety & Reliability Risk Reduction
680	0.503733	3.104029	16%
880	0.597408	3.104029	19%
1,080	0.682550	3.104029	22%
1,280	0.758148	3.104029	24%
1,480	0.828946	3.104029	27%
1,680	0.893329	3.104029	29%

*Figure 25 Conductor length vs. Safety-Reliability Risk Reduction per SCE's OCP ML Model*

An Ordinary Least Squares (OLS) model based on provided data is used to interpret SCE's risk reduction as a function of covered conductor miles. A simple linear regression model suggests a high correlation coefficient (=0.996) indicating, as shown below graphically, that a linear

<sup>82</sup> TURN-SCE-072, Q3.f

<sup>83</sup> PubAdv-SCE-140

relationship exists between risk reduction and covered conductor miles. TURN notes that due to a very small dataset (n=6), the results should be interpreted with caution, despite being statistically significant. Notwithstanding this, the relationship is surprising, indicating that SCE’s risk-reduction modeling suggests near-linear risk reduction for every unit increase in covered conductor length from 680 to 1,680 miles.<sup>84</sup> In contrast, SCE’s previous modeling shows significantly diminishing returns from covered conductor in HFRAs, specifically: “SCE’s RAMP and GRC wildfire risk analyses show that the top 90% of wildfire risk in the HFTD is contained within approximately 2,200 or 1,800 circuit miles, respectively.”<sup>85</sup>

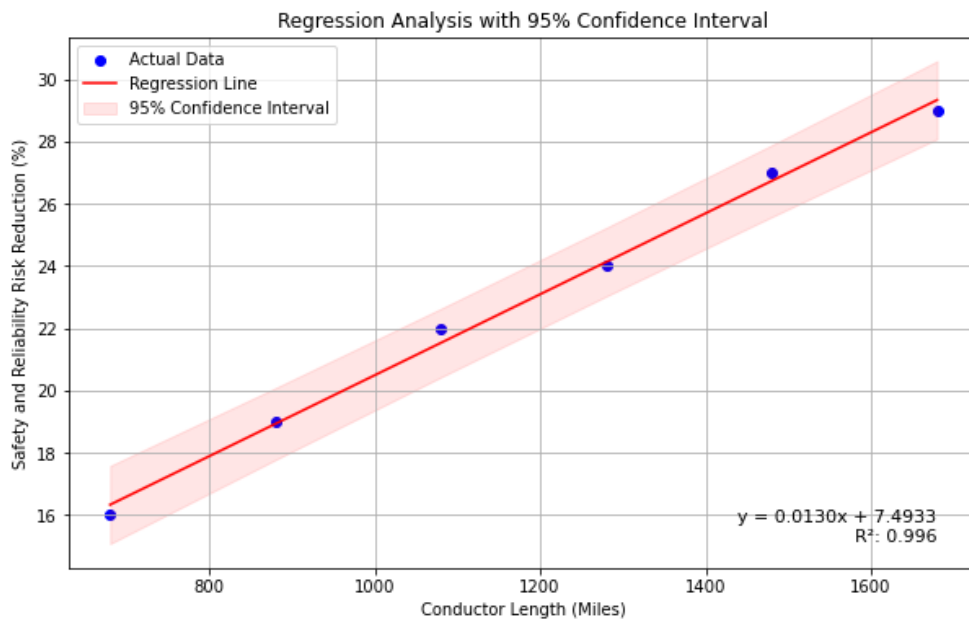


Figure 26 Regression analysis of Risk Reduction (y) as a function of Conductor Length (x)

**TURN’s Recommendations (Detailed):**

The benefit-cost of a recurring annual investment of >\$330m (Nominal) from 2025-2028 is not adequately justified, even considering SCE’s likely over-estimated safety and reliability benefits.

<sup>84</sup> SCE’s OCP model indicates a 0.013% increase in safety and reliability risk reduction for every circuit mile of covered conductor. TURN notes that this linear trend and risk reduction % seems like an exaggerated number.

<sup>85</sup> Based on TURN’s analysis from SCE’s 2022 RAMP filing. TURN calculated “percentiles” of risk with RAMP data that ranks circuits according to their “MARS” score (Multiattribute Risk Score).

- TURN recommends rejecting all OCP scope except small-gauge wire (due to higher probability of failure) and Accelerated Overhead Conductor Program (AOCP).
- TURN further recommends disallowing bare conductor-based replacement of 117 and 91 miles in 2023 and 2024 respectively, owing to SCE’s demonstration of low benefit-cost for bare conductor replacement.
- TURN recommends assessment of benefit-cost of “Splice/Connector/Tap” replacement in the next GRC as these low-cost components account for 3% of wire-down events, whereas conductor makes up for 7% of OH Equipment Failure SAIDI.<sup>86</sup>
- TURN agrees that contact with energized wire-down events poses a grave safety threat – however, as explained by SCE in response to TURN’s DR, ‘SCE does not track SIF data by circuit segment/location.’ Therefore, it is impossible to ascertain whether the ML model-based circuit segments would result in any reduced SIF or Potential SIFs.

#### **4.2.1 Underground Cable Replacement (UCR):**

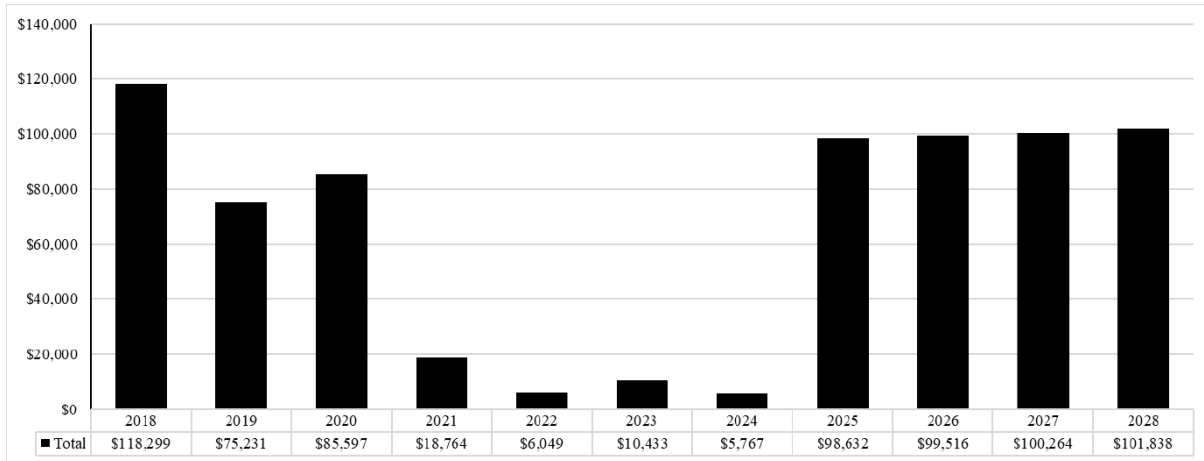
In SCE’s 2021 GRC, the Underground Cable Replacement (UCR) program -- formerly called Worst Circuit Rehabilitation (WCR)—was combined with the Worst-Performing Circuit (WPC) program. WPC focuses on historically unreliable circuits, while UCR is aimed at preemptively addressing risks in high-risk primary underground cables.<sup>87</sup>

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<sup>86</sup> TURN-SCE-072 Q05.c

<sup>87</sup> SCE-02, Vol. 1, Pt. 2, p. 28-29.

***Underground Cable Replacement Program<sup>43,44</sup>***  
***Multiple WBS Elements<sup>45</sup>***  
***Recorded (2018-2022)/Forecast (2023-2028)***  
***(Total Company – Nominal \$000)***



*Figure 27 Nominal program costs (Recorded 2018-2022 vs. Forecasted 2023-2028) for Underground Cable Replacement (UCR).*

4.2.2 TURN’s Recommendation:

**TURN has no objection to WPC in concept but proposes that the Commission allow 800 miles replacement (against SCE’s proposal of 1,600 miles) from 2025-2028 to achieve 60 - 70% of safety and reliability related benefits according to SCE’s ML model for UCR. TURN’s proposed replacement incurs an authorized total program cost of \$214.631m (Nominal) against SCE’s “corrected” proposal of \$413.057m (Nominal) from 2023-2028 as shown below:**

	2023	2024	2025	2026	2027	2028	Total (Nominal)
Miles (SCE)	46	24	400	400	400	400	1670
Unit Cost	216	216	216	216	216	216	
Escalation Rate	1.054	1.106	1.133	1.143	1.151	1.167	
Employee Compensation Program <sup>1</sup>	67	380	972	1031	1091	1221	
UCR Capital (SCE) <sup>2</sup>	\$ 10,471	\$ 5,733	\$ 97,886	\$ 98,713	\$ 99,403	\$ 100,850	\$ 413,057
Miles (TURN)	46	24	200	200	200	200	870
UCR Capital (TURN)	\$ 10,470.89	\$ 5,733.47	\$ 48,943.22	\$ 49,356.56	\$ 49,701.66	\$ 50,424.97	\$ 214,631

<sup>1</sup> Employee compensation program is excluded from the analysis due to uncertainty regarding its use in the calculations. TURN’s calculation results in \$413.057m compared to SCE’s \$416.450m (Nominal)

*Underground Cable Replacement (UCR) proposal (2023-2028). UCR Capital (SCE) refers to corrected SCE total and UCR Capital (TURN) refers to total (Nominal \$000) based on TURN’s proposed replacement.*

For comparison, SCE’s calculations from Table II-6, pg. 39 is given below:

***Cost Breakdown of the Underground Cable Replacement Program  
Forecast (2023-2028)  
(Nominal \$000)***

		2023	2024	2025	2026	2027	2028	Total
(1)	Conductor Miles Replaced	46	24	400	400	400	400	1,670
(2)	UCR Unit Cost (2022\$) (\$000)	\$ 216	\$ 216	\$ 216	\$ 216	\$ 216	\$ 216	N/A
(3)	Escalation	1.054	1.106	1.133	1.143	1.151	1.167	N/A
(4)	Employee Compensation Program	67	380	972	1,031	1,091	1,221	4,763
(5)	<b>Total (Nominal \$000)</b>	<b>\$ 10,433</b>	<b>\$ 5,767</b>	<b>\$ 98,632</b>	<b>\$ 99,516</b>	<b>\$ 100,264</b>	<b>\$ 101,838</b>	<b>\$ 416,450</b>

4.2.3 SCE’s ML model-based safety and reliability benefits are likely over-stated:

SCE's predictive modeling aims to identify and mitigate underground cable-related failures by replacing potentially overloaded circuits, moving away from a "minimum age" criterion (from 34 to 41 years as directed in D.19-05-020 of the 2018 GRC) to a risk-based approach for cable replacement. SCE proposes an aggressive strategy to replace 1,600 conductor miles of underground cable between 2025-2028, a plan designed to address the identified safety and reliability risks. This approach, necessitating significant capital investment, deviates from the traditional age-based replacement policy, now leveraging predictive analytics that suffer from the inability to perform adequate scrutiny mentioned in the previous sections. The lack of adequate quantitative or qualitative information of the underlying model, assumptions, data used etc. undermines veracity of SCE’s projected safety and reliability benefits.

SCE's capital investment proposal, while well-intentioned, may represent an overly conservative approach that significantly increases costs without proportionate benefits. The shift from a "minimum age" criterion to a risk-based model, though innovative, requires scrutiny to ensure that the predictive analytics accurately identify high-risk scenarios without leading to unnecessary replacements.

4.2.4 ‘Other’ and/or ‘Unknown’ Causes of Underground Cable Failure undermine SCE’s emphasis on Cable Loading / Fatigue-related causes of failure:

SCE’s data, as presented in the 2025 GRC, reveals an aging underground cable infrastructure with an average cable lifespan of 38 years and approximately 1,300 failures annually since 2017, attributed to a variety of causes such as equipment and component failures, cable loading, and water intrusion. Rather than the UCR program's approach of preemptively replacing 1,600 miles of cable, which somewhat overlooks the multifaceted nature of the failure causes, a more nuanced response may include conducting root cause analysis for component failures, cable loading, and water intrusion as a lower-cost alternative to wholesale replacement.

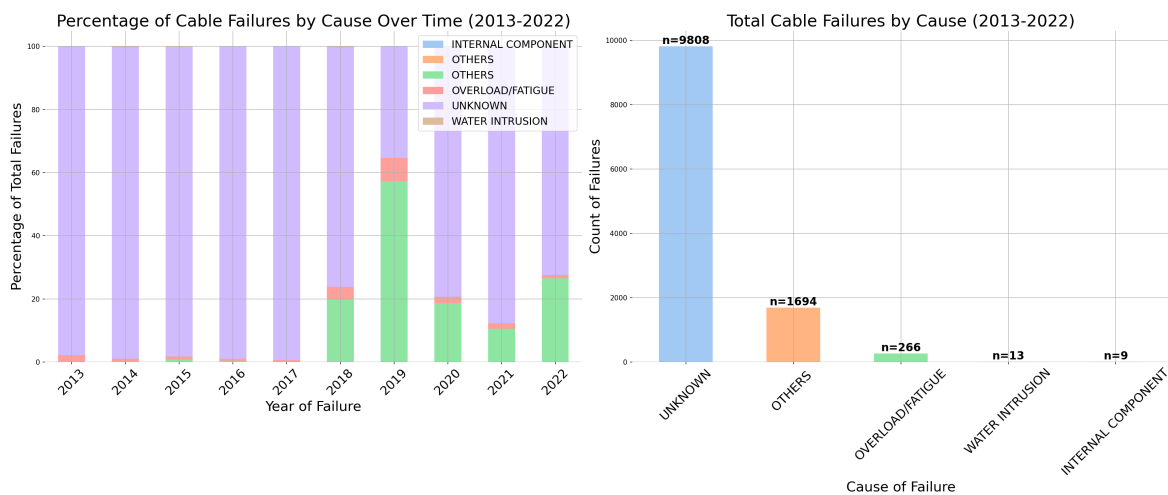
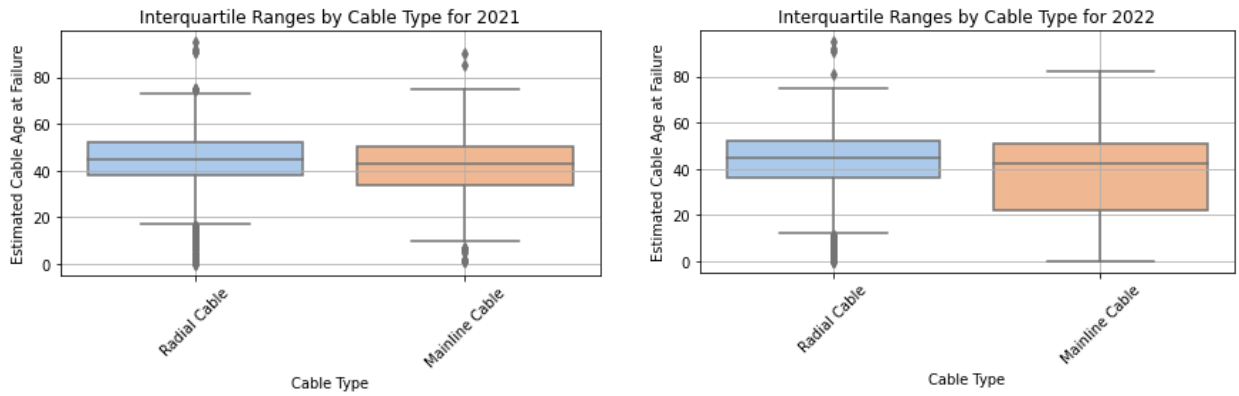


Figure 28 Percentage and Number of Cable Failures by Causes (2013-2022)

#### 4.2.5 Existing 41 Year Cable Age Threshold for Replacement may need to be lowered for Mainline Cable:

SCE states on pg. 37: “...SCE is proposing to proactively replace 1,600 conductor miles of mainline underground cable from 2025-2028 to adequately mitigate the safety and reliability risks associated with underground cable and component failure. ...”<sup>88</sup> A large population of failing mainline cable is <40 years cable, as evidenced by recent (2021 and 2022) cable failure data, suggesting that the Commission’s <41 year old cable replacement threshold may be reduced even further for mainline cable (as opposed to radial cable):

<sup>88</sup> SCE 02, Vol. 01, Pt. 2



According to SCE response to PAO’s DR<sup>89</sup>, the Safety and Reliability Risk Reduction goes substantially down after the first 800 miles of replacement. The steepest safety/reliability benefit vs. miles replaced is expected for the first 800 miles of underground cable, and as shown by the concave-down curve for Safety-Reliability Risk Reduction vs. Miles of Cable Replaced, most (projected) benefits from replacement may be achieved by replacing fewer miles than SCE recommends.

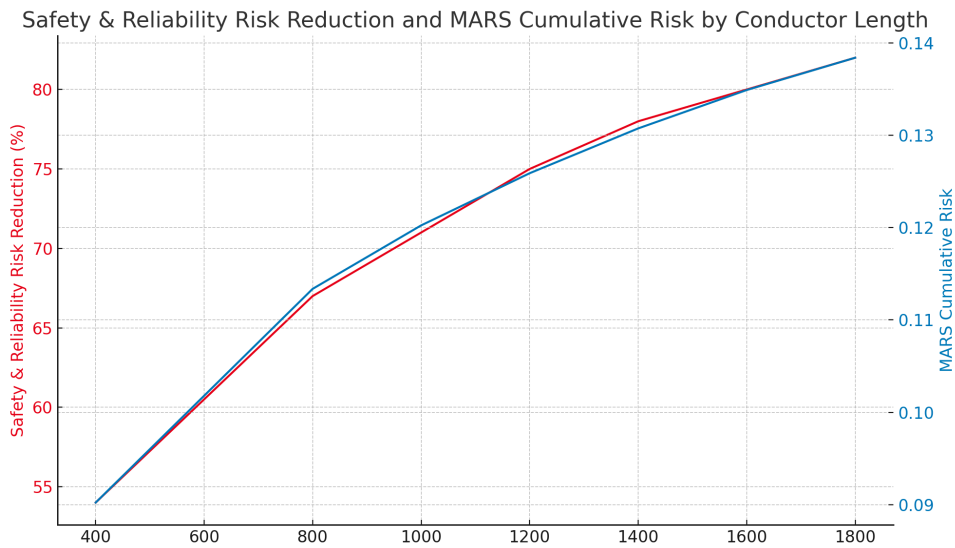


Figure 29 Safety-Reliability Risk Reduction vs. Miles of Cable Replaced

<sup>89</sup> 01.b\_PubAdv-SCE-133-GAW\_1b\_RiskModel\_20230829

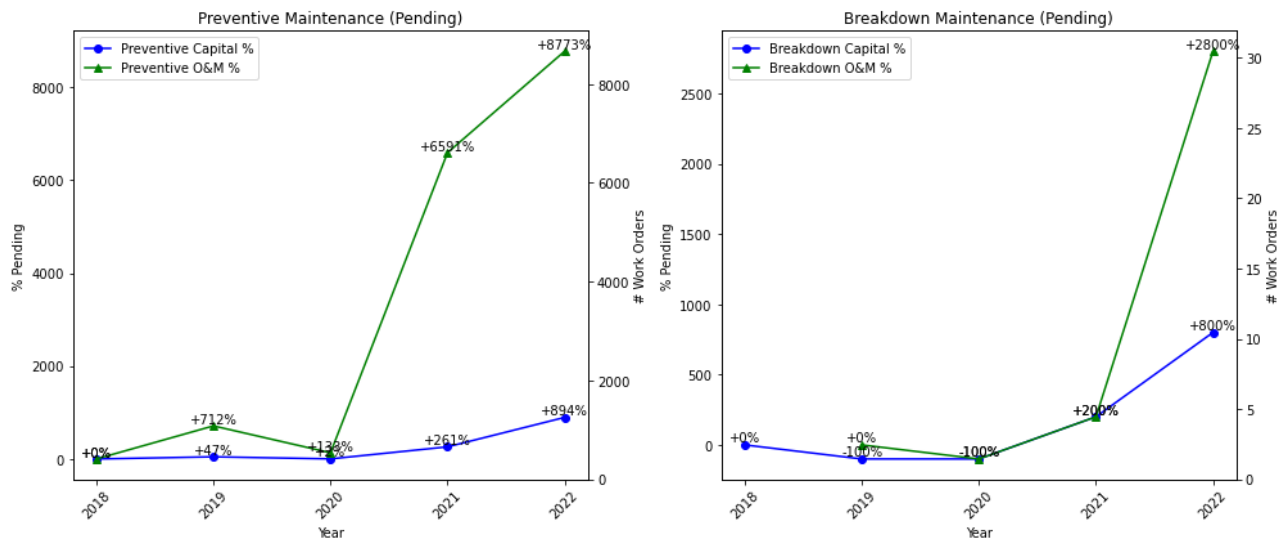
TURN does not contest 2023-2024 underground cable replacement miles proposed by SCE. Overall, TURN's proposed underground cable replacement scope would incur a total program cost of \$214.6.3m (Nominal) against SCE's proposal of ~\$413m (Nominal) from 2023-2028 as shown below:

## Appendix

### 1a (Comparison of 2021 Authorized vs. 2025 Requested Costs by Exhibit Volume)

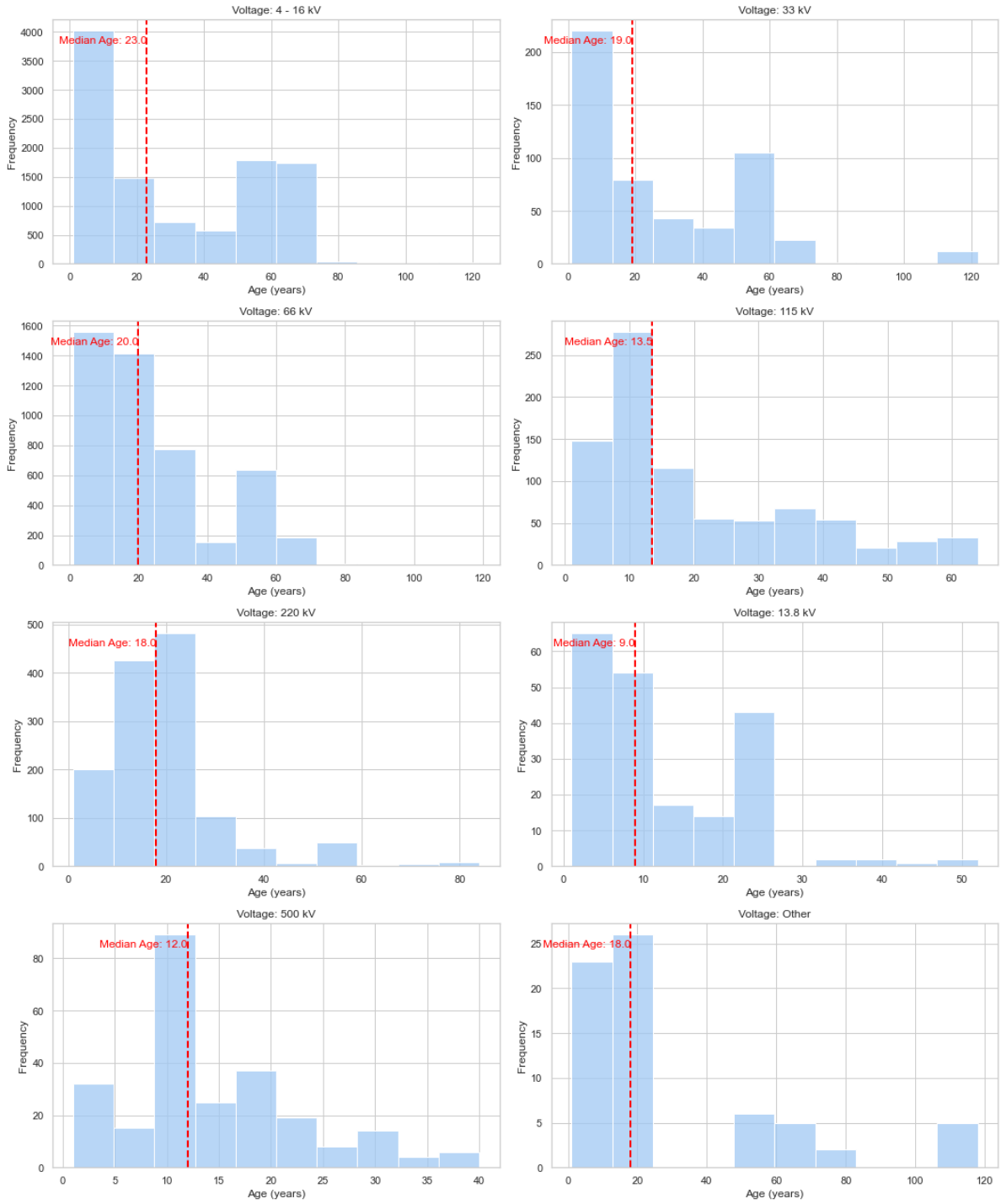
Exhibit Volume	2021 O&M Authorized	2021 Capital Authorized	2025 O&M Request	2025 Capital Request	% Difference (O&M) 2021 Authorized vs. Requested	% Difference (Capital) 2021 Authorized vs. Requested
Vol. 1, Pt. 2: Infrastructure Replacement	\$ -	\$ 143.00	\$ -	\$ 804.00	0%	462%
Vol. 2: Distribution Inspections & Maintenance and Capital-Related	\$ 188.00	\$ 518.00	\$ 209.00	\$ 760.00	11%	47%
Vol. 4: Transmission Grid	\$ 44.00	\$ 229.00	\$ 31.00	\$ 363.00	-30%	59%
Vol. 5: Substation	\$ 135.00	\$ 462.00	\$ 176.00	\$ 569.00	30%	23%
<b>Total</b>	<b>\$ 367.00</b>	<b>\$ 1,352.00</b>	<b>\$ 416.00</b>	<b>\$ 2,496.00</b>	<b>13%</b>	<b>85%</b>

### 2a (Percentage difference in “Pending Notifications” with 2018 as baseline year)

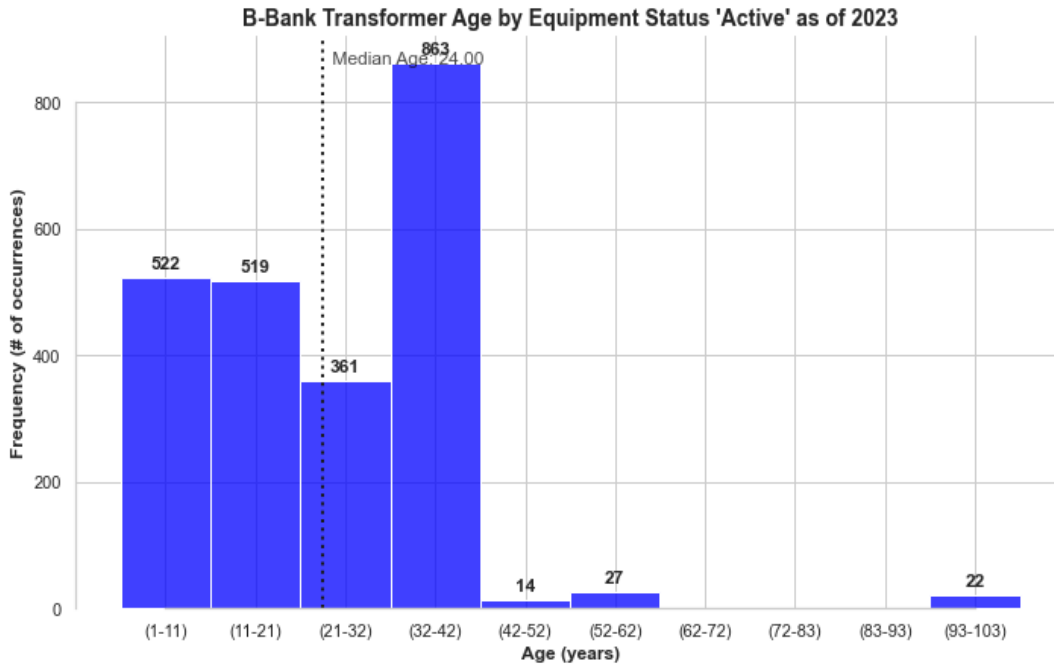
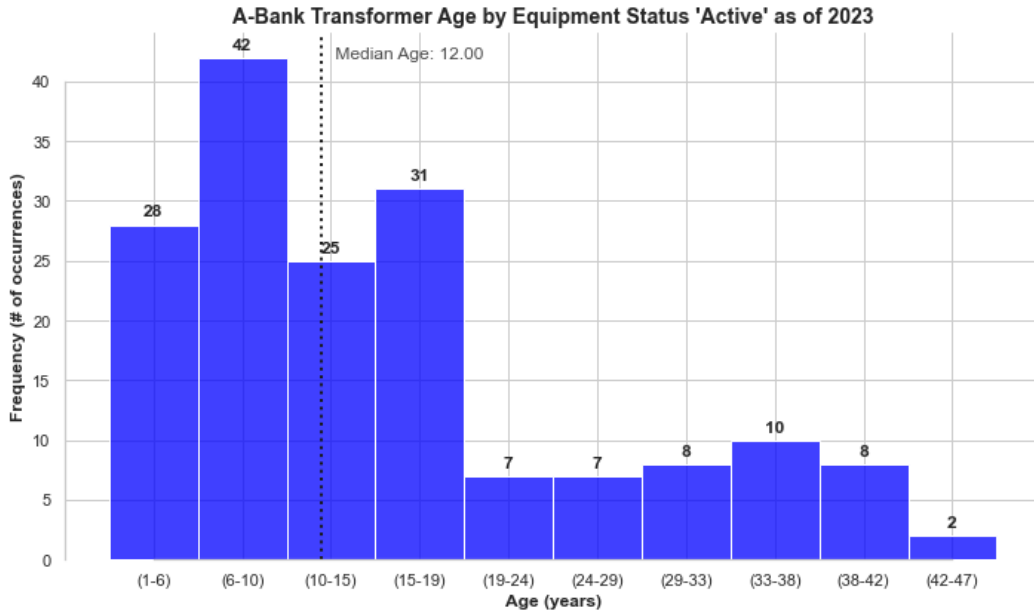


### 3a (Circuit Breaker Median Age by Voltage Class)

Distribution of CB Age by Voltage Category



4a (Transformer Median Age by Type)



**Attachment 1 (Resume)**

# Jalal Awan

mawan@usc.edu | (424) 302-6637 | San Francisco, CA

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## SUMMARY

Electrical power systems engineer with a Ph.D. in Public Policy analysis and 10+ years' experience in energy systems, technology, and climate policy.

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## WORK EXPERIENCE

- |   |  |
|---|--|
| <p>The Utility Reform Network (TURN)<br/><i>Expert Witness</i></p> <ul style="list-style-type: none"><li>• Conduct analyses and prepare testimony as expert witness on electric utility-related regulatory issues before the California Public Utilities Commission</li><li>• Present both written and oral testimony at California Public Utilities Commission hearings on topics such as General Rate Cases, building electrification, community microgrids, and wildfire mitigation plans.</li><li>• Sponsored testimony on building electrification resulting in rejection of a \$677 million electrification proposal (2023) through methodologies such as cost-benefit and net-present value assessments.</li></ul>   | <p>Remote<br/>Nov 2023 - Present</p>                         |
| <p>RAND CORPORATION<br/><i>Policy Researcher</i></p> <ul style="list-style-type: none"><li>• Conducted a comprehensive cost-benefit analysis of emerging transportation modalities, providing critical insights for state Department of Transportation and Metropolitan Planning Organizations.</li><li>• Formulated a risk assessment framework for Industrial Control Systems potentially impacted by advancements in quantum computing.</li><li>• Assessed the feasibility of implementing community microgrid tariffs for solar, combined heat and power (CHP), and fuel-cell based technologies.</li><li>• Constructed, evaluated, and launched a web-based toolkit for health entities, enabling effective engagement in COVID-19 response efforts.</li><li>• Participated as a panel member with National Cooperative Highway Research Program (NCHRP) on RFP development (including scoping, budgeting, and timelines for approx. \$3.5m federal-funded projects), contractor selection and progress reporting.</li></ul> | <p>Santa Monica, CA<br/>2017 - 2023</p>                      |
| <p>ENGRO CORP (formerly Exxon Mobil)<br/><i>Electrical Engineer / Health, Safety &amp; Environment Engineer</i></p> <ul style="list-style-type: none"><li>• Leveraged specialized knowledge in electric grid distribution and protection to successfully execute a programmable logic control-based load-shedding scheme, reducing downtime and improving overall plant reliability by &gt;50%.</li><li>• As the Lead Engineer, oversaw the procurement and commissioning of Siemens &gt;1kV rated AC switchgear and control gear, in compliance with IEC and IEEE standards,</li><li>• Managed the design, installation, and grid integration of 1MW solar PV panels with 1000Ah battery bank.</li><li>• Additionally, led health, safety &amp; environment division at utility-scale electric generation facility in line with Dupont / OSHA standards.</li></ul>   | <p>Daharki, Pakistan<br/>2010 - 2014 and 2016 -<br/>2017</p> |

International Institute for Applied Systems Analysis (IIASA)	Vienna, Austria
<i>Research Fellow</i>	Jun 2023 - Aug 2023
<ul style="list-style-type: none"> <li>• Collaborated with the Advancing Systems Analysis team to evaluate human-sensor systems within a citizen science framework.</li> <li>• Utilized sensor and survey data to perform comprehensive performance assessments in Vienna, Austria.</li> <li>• Participated in the Young Scientists Summer Program as a US National Academy of Sciences fellow, contributing to the advancement of Systems Analysis.</li> </ul>	

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EDUCATION	Pardee RAND Graduate School PhD in Public Policy Analysis (Technology Policy), Dissertation: 'Evaluating socio-technical systems for improved reliability: Evidence from sensor-human networks.'	Santa Monica, CA Sep 2023
	University of Southern California (Fulbright Scholar) Master of Science in Green Technologies, Relevant Courses Completed: Sustainable Design and Construction, Lifecycle Impact Analysis, Smart Grids – Design and Operation, Energy Auditing, Leadership in Energy & Environmental Design (LEED) Certification.	Los Angeles, CA Dec 2015
	University of Engineering and Technology Lahore Bachelor of Science in Electrical Power Systems Engineering	Lahore, Pakistan Jul 2010

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CERTIFICATIONS	President, Fulbright Greater Los Angeles Chapter, Fulbright Association Leadership in Energy and Environmental Design (LEED) GA Certified, US Green Building Council	2023- '24 2018-'19
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SKILLS	Lifecycle Analysis (EIO-LCA, GREET), Environmental Impact Assessment (NREL ReOPT), Financial Analysis (NPV, Cost-Benefit), Solar Design (PVWatts), Load-Flow and Short-Circuit Analysis (EnergyPlus.net, Siemens SINICAL, ETAP) • EPA Criteria Pollutant Trending and Monitoring Using Open-Source Data • Advanced Programming and Statistical Analysis Using Python (SciPy, Matplotlib, Scikitlearn, PyPower) • Project Management
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PUBLICATIONS	<i>Publications List</i> , RAND Corporation <ul style="list-style-type: none"> <li>• <a href="https://www.rand.org/pubs/authors/a/awan_muhammad_jalal.html">https://www.rand.org/pubs/authors/a/awan_muhammad_jalal.html</a></li> </ul> <i>Google Scholar Profile</i> <ul style="list-style-type: none"> <li>• <a href="https://scholar.google.com/citations?user=0A3_DZUAAAAJ&amp;hl=en">https://scholar.google.com/citations?user=0A3_DZUAAAAJ&amp;hl=en</a></li> </ul>	Sep 2017 - Oct 2023 Sep 2017 - Feb 2024
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## Attachment 2 (Data Requests included)

DR
TURN-SCE-015, Q03.a
TURN-SCE-015, Q03.b
TURN-SCE-015, Q03.c
TURN-SCE-015, Q4-b
TURN-SCE-015, Q4-a
TURN-SCE-043.Q2.b
TURN-SCE-043 Q4.b
TURN-SCE-053 Q06.a-b
TURN-SCE-072 Q3.a
TURN-SCE-072 Q4.a-b
TURN-SCE-072 Q5.c
TURN-SCE-072 Q5.b
TURN-SCE-072, Q1.b
TURN-SCE-072- Q1.a
TURN-SCE-072, Q3.a-e
TURN-SCE-072, Q3.f
TURN-SCE-072 Q05.c

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 1 5**

**To: TURN**  
**Prepared by: Erin McElrath**  
**Job Title: Advisor**  
**Received Date: 11/30/2023**  
  
**Response Date: 12/14/2023**

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**Question 03.a-b:**  
RE SCE-02 Vol. 0:

a) Please define every type of maintenance activity (e.g. corrective / preventative / breakdown etc.) referenced in the application and the categories of workorders for each maintenance activity type.

b) Provide a 5-year history of maintenance records per the following (or equivalent table):

<b>Preventive Maintenance (PM) or similar</b>						
<b>Work Order Category</b>	<b>Definition</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>
Priority	P1					
	P2					
	...					

<b>Work Order Status</b>	<b>Open / Close / Unassigned etc.</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>2022</b>
	Open					
	Close					
	Unassigned					
	...					

Corrective Maintenance (PM) or similar						
Work Order Category	Definition	2018	2019	2020	2021	2022
	P1					
	P2					
	...					
Work Order Status	Open / Close / Unassigned etc.	2018	2019	2020	2021	2022
	Open					
	Close					
	Unassigned					
	...					

### Response to Question 03.a-b:

- a. SCE objects to this question on the grounds that the phrasing “every type of maintenance activity referenced in the application” is vague, ambiguous, and overbroad. Subject to and without waiver of this objection, SCE responds as follows:

SCE interprets this statement as asking for priority maintenance notifications driven by inspections. Please see definitions below.

Priority 1 (P1): Notifications for conditions which pose an immediate risk of high potential impact to safety or reliability.

Priority 2 (P2): Notifications for conditions which pose a risk of moderate potential impact to safety or reliability. These notifications require action anywhere from the same day up to 36 months of the notification date depending on the condition and the location.

Priority 3 (P3): Notifications for conditions which pose a risk of low potential impact to safety or reliability, GO 95 or GO 128 infractions, and programmatic replacement work.

Priority 9 (P9): For Distribution, these notifications are for repairs completed by inspectors during an inspection.

- b. Please see attachment “TURN-SCE-015\_Q3.b.xlsx” for breakdown of notifications for Preventive and Breakdown Maintenance Capital and O&M. The attachment is categorized by the year the notification was created. Generally, data provided for these types of requests is categorized by year completed. In this case the data is categorized by year found/created. The criteria for the data provided are maintenance notifications driven by inspections. Please note that the current high fire ratemaking criteria is being used. As such, only non-high fire notifications were provided in this data set. High Fire notifications were not included in this data set; therefore, High Fire notifications that remained in base rates (were not recovered or considered for WF treatment) were not included in this data set. Additionally, the data

provided only includes notification-driven maintenance work. It does not include any maintenance work that settled directly to a Work Order without a notification assignment. The closed/pending status is based on current status as of the date the data was queried.

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 1 5**

**To: TURN**

**Prepared by: Diyana Siem**

**Job Title: Senior Advisor**

**Received Date: 11/30/2023**

**Response Date: 12/13/2023**

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**Question 03.c:**

RE SCE-02 Vol. 0:

c) Provide a similar table with work orders in a) disaggregated by how the work order was triggered i.e. via Distribution Ground Inspection, Underground Detailed Inspection, DIMP, Inspect App or any other activit(ies). Please identify duplicate work orders (if any) and provide reasons for duplication.

**Response to Question 03.c:**

c. Please see attachment “TURN-SCE-015\_Q3.c.xlsx” for breakdown of notification drivers. There are four tabs distinguishing Preventive and Breakdown Maintenance for O&M and Capital. The data provided is the same data provided in TURN-SCE-015 question 3.b. Please see TURN-SCE-015 question 3.b. for specific criteria.

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 1 5**

**To: TURN**  
**Prepared by: Jeff Lawrence**  
**Job Title: Bus Ops Anlys, Sr Mgr**  
**Received Date: 11/30/2023**

**Response Date: 12/15/2023**

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**Question 04.a-c:**

RE SCE-02 Vol. 02:

- a) Please provide all results (-to date) from Inspect App surveys in working Excel format.
- b) Please provide an explanation of how sites / structures for Inspect App survey were identified.
- c) Please provide results from SCE's analysis of Inspect App surveys, including highlevel information on total number of surveys, conducted by (SCE Employee / Contractor etc.), time to complete each survey etc.

**Response to Question 04.a-c:**

- a. Please see attachment TURN-SCE-015 Q4.a.xlsx for Inspect App surveys 2023 year to date. The data provided are for all inspections that used Inspect App survey. As such, the survey data includes Distribution ground and aerial High Fire Inspections (discussed in SCE 04 Volume 5 Part 3) and Distribution ground only compliance Inspections (discussed in SCE 02 Volume 2). The survey data only includes inspections where the Inspect App Survey was completed. The survey data does not include Underground Detail Inspections or Annual Grid Patrol, as they do not utilize the survey. Additionally, the survey data does not include any ensuing maintenance notifications or other notifications that may have been driven by the inspection. Lastly, the names of the employees and contractors have been removed from this data.
- b. The inspections are completed based on wildfire risk and/or by compliance schedule.
- c. Please see table below for a breakdown of total number of surveys by SCE Employee and Contractor and average time to complete for each. The time taken to complete the survey is based on when the survey was opened and when the survey was completed in InspectApp. Activities such as travel, mobilizing, and demobilizing are excluded from the time data. Furthermore, SCE excluded any inspection times greater than 90 minutes to exclude inaccurate outlying inspection times which would inflate inspection times.

<b>Inspector</b>	<b>Inspect App Surveys</b>	<b>Time (excluding surveys over 90m)</b>
SCE	127,642	0:20:35
Non-SCE	209,008	0:19:51
Total	336,650	0:20:11

**Preventive Maintenance Capital**

	2018			2019			2020			2021			2022		
	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total
P1	0	15	15	0	39	39	0	14	14	0	23	23	0	20	20
P2	32	9,576	9,608	76	10,475	10,551	93	7,115	7,208	406	6,740	7,146	1,366	4,242	5,608
P3	112	793	905	135	975	1,110	54	472	526	114	386	500	66	174	240
P9	0	0	0	0	0	0	0	1	1	0	0	0	0	1	1
<b>Total</b>	<b>144</b>	<b>10,384</b>	<b>10,528</b>	<b>211</b>	<b>11,489</b>	<b>11,700</b>	<b>147</b>	<b>7,602</b>	<b>7,749</b>	<b>520</b>	<b>7,149</b>	<b>7,669</b>	<b>1,432</b>	<b>4,437</b>	<b>5,869</b>

**Preventive Maintenance O&M**

	2018			2019			2020			2021			2022		
	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total
P1	0	222	222	0	281	281	0	329	329	0	311	311	0	261	261
P2	12	17,355	17,367	22	23,702	23,724	158	17,765	17,923	6,099	15,204	21,303	8,193	8,296	16,489
P3	73	987	1,060	728	1,096	1,824	55	1,219	1,274	124	183	307	55	113	168
P9	8	315,402	315,410	5	281,968	281,973	4	275,210	275,214	0	248,228	248,228	4	215,674	215,678
Unassigned	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0
<b>Total</b>	<b>93</b>	<b>333,968</b>	<b>334,061</b>	<b>755</b>	<b>307,047</b>	<b>307,802</b>	<b>217</b>	<b>294,523</b>	<b>294,740</b>	<b>6,223</b>	<b>263,926</b>	<b>270,149</b>	<b>8,252</b>	<b>224,344</b>	<b>232,596</b>

**Breakdown Maintenance Capital**

	2018			2019			2020			2021			2022		
	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total
P1	0	7,815	7,815	0	8,910	8,910	0	8,393	8,393	0	7,803	7,803	8	7,954	7,962
P2	0	14	14	0	20	20	0	13	13	3	20	23	1	28	29
P3	1	5	6	0	11	11	0	1	1	0	1	1	0	0	0
<b>Total</b>	<b>1</b>	<b>7,834</b>	<b>7,835</b>	<b>0</b>	<b>8,941</b>	<b>8,941</b>	<b>0</b>	<b>8,407</b>	<b>8,407</b>	<b>3</b>	<b>7,824</b>	<b>7,827</b>	<b>9</b>	<b>7,982</b>	<b>7,991</b>

**Breakdown Maintenance O&M**

	2018			2019			2020			2021			2022		
	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total	Pending	Closed	Total
P1	0	4,658	4,658	0	5,557	5,557	0	5,081	5,081	0	4,818	4,818	12	4,569	4,581
P2	0	316	316	1	179	180	0	182	182	3	222	225	17	186	203
P3	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0
<b>Total</b>	<b>0</b>	<b>4,974</b>	<b>4,974</b>	<b>1</b>	<b>5,736</b>	<b>5,737</b>	<b>0</b>	<b>5,264</b>	<b>5,264</b>	<b>3</b>	<b>5,040</b>	<b>5,043</b>	<b>29</b>	<b>4,755</b>	<b>4,784</b>

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 4 3**

**To: TURN**

**Prepared by: Myn Kim**

**Job Title: Senior Advisor**

**Received Date: 1/3/2024**

**Response Date: 1/17/2024**

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**Question 02.a-d:**

Re. SCE-02 Vol. 05, the following set of questions refer to Section V. “Substation Infrastructure Replacement” (pp. 132-188):

a) Refer p. 139, Table V-19 titled “Substation Equipment Health Index and Health Condition”, please identify and briefly describe describe each input (including the weight given to each input, if applicable) used to calculate the numeric Equipment Health Index for Power Transformers and Circuit Breakers, as shown in Table V-20 and Table V-22 respectively.

b) For Table V-20 (“Distribution of A and B Bank Power Transformers by Health Condition as of 2022 Year End”) and Table V-22 (“Circuit Breakers by Health Condition as of 2022 Year End”, please provide the following two tables in .xls format as follows:

c) For Table V-21 (“Power Transformer Replacement Program CET-ET-IR-TB Recorded (2018-2022) / Forecast (2023-2028)”) and Table V-23 (“Circuit Breaker Forecast Installations Recorded 2018-2022 /Forecast 2023-2028”) respectively, please provide the following information in .xls format for recorded and forecast installation(s) by health condition as follows:

d) Refer to SCE-02, Vol. 5, at p. 138, line 19, SCE states, “...Over the past 13 years, SCE experienced 23 power transformer failures...”

i) Please provide incident reports or similar records for each of the subject 23 power transformer failures (including, but not limited to all relevant details, such as equipment rating, make/model, manufacturer recommended MTTR/MTBF).

ii) Please provide history, including but not limited to, equipment asset age at time of failure, Dissolved Gas Analysis (DGA) results, field test data, repair history, and historic (5 years prior) asset health condition (Very Good, Good etc.) for subject equipment in the response to (i), above)

iii) Refer to WPSCE02V05, pp. 183-190, titled “B Bank Transformer Health Condition”, please provide a table similar to the one titled “Substation Infrastructure Replacement B Bank Transformer in Scope with Health Index (CET-ET-IR-TB),” but for (Actual) Installation Years 2018-2022 rather than the forecasted information for 2023-2025, in .xls format. For each of the 2018-2022 installations, please provide all information included in referenced table, including age, condition, and health index.

<b>Health Condition as of Year</b>	<b>Power Transformer(s)</b>	<b>Very Good</b>	<b>Good</b>	<b>Fair</b>	<b>Poor</b>	<b>Very Poor</b>	<b>Total</b>
2018	A Bank						
	B Bank						
2019	A Bank						
	B Bank						
2020	A Bank						
	B Bank						
2021	A Bank						
	B Bank						
2022	A Bank						
	B Bank						

*Table: Circuit Breaker health condition by year*

<b>Health Condition as of Year</b>	<b>Circuit Breaker(s)</b>	<b>Very Good</b>	<b>Good</b>	<b>Fair</b>	<b>Poor</b>	<b>Very Poor</b>	<b>Total</b>
2018	2.4kV to 115kV						
	220kV to 500kV						
2019	2.4kV to 115kV						
	220kV to 500kV						
2020	2.4kV to 115kV						
	220kV to 500kV						
2021	2.4kV to 115kV						
	220kV to 500kV						
2022	2.4kV to 115kV						
	220kV to 500kV						

*Table: Power Transformer (recorded and forecast) Health Condition by year*

<b>Installations recorded 2018-2022 / Forecast* 2023-2028</b>	<b>Power Transformer(s)</b>	<b>Very Good</b>	<b>Good</b>	<b>Fair</b>	<b>Poor</b>	<b>Very Poor</b>	<b>Total</b>
2018	A Bank						
	B Bank						
2019	A Bank						
	B Bank						
2020	A Bank						
	B Bank						
2021	A Bank						
	B Bank						

2022	A Bank						
	B Bank						
2023	A Bank						
	B Bank						
2024	A Bank						
	B Bank						
2025	A Bank						
	B Bank						
2026	A Bank						
	B Bank						
2027	A Bank						
	B Bank						
2028	A Bank						
	B Bank						

*\*Forecast refers to health condition of equipment in Table V-21 to be replaced*

*Table: Circuit Breaker recorded and forecast Health Condition by year*

<b>Installations recorded 2018-2022 / Forecast* 2023-2028</b>	<b>Circuit Breaker(s)</b>	<b>Very Good</b>	<b>Good</b>	<b>Fair</b>	<b>Poor</b>	<b>Very Poor</b>	<b>Total</b>
2018	2.4kV to 115kV						
	220kV to 500kV						
2019	2.4kV to 115kV						
	220kV to 500kV						
2020	2.4kV to 115kV						
	220kV to 500kV						
2021	2.4kV to 115kV						
	220kV to 500kV						
2022	2.4kV to 115kV						
	220kV to 500kV						
2023	2.4kV to 115kV						
	220kV to 500kV						
2024	2.4kV to 115kV						
	220kV to 500kV						
2025	2.4kV to 115kV						
	220kV to 500kV						
2026	2.4kV to 115kV						
	220kV to 500kV						
2027	2.4kV to 115kV						
	220kV to 500kV						
2028	2.4kV to 115kV						
	220kV to 500kV						

*\*Forecast refers to health condition of equipment in Table V-23 to be replaced*

**Response to Question 02.a-d:**

- a) The current version “Substation Equipment Health Index and Health Condition<sup>1</sup>” (including the weight given to each input, if applicable) used to calculate the numeric Equipment Health Index for Power Transformers and Circuit Breakers, as shown in Table V-20 and Table V-22 respectively are shown below:

**The Transformer Health Index** and Health Condition inputs and weights given to each input are as followed:

**Dissolved Gas Analysis (DGA):**

The DGA process provides a comprehensive set of data to help determine the health of the transformer while in service. It involves the analysis of dissolved gases within transformer oil that can demonstrate a particular kind of failure modes. The benefits of the DGA process include:

- Detecting first indication of a possible malfunction
- Aiding reduction of in-service failures
- Prescribing a recommended course of action

A. Solid Insulation	100%
A1. Transformer Oil Analysis (TOA) Manual	Dissolved Gas Analysis (DGA) condition codes/Furan Testing
A2. Furan Analysis	
A7. Hydrogen (H2)	
A8. Methane (CH4)	
A9. Ethane (C2H6)	
A10. Ethylene (C2H4)	
A11. Acetylene (C2H2)	
A12. Carbon Monoxide (CO)	
A13. Carbon Dioxide (CO2)	
A14. Total Dissolved Combustible Gas	
A15. Transformer Oil Analysis (TOA) On-Line	

**Oil Tap Changer Analysis (TOA)**

The TOA facilitates the dissolved gas analysis (DGA) and fluid quality analysis to monitor trends that verify the maintenance and lifespan of transformers in the system. It is imperative to understand the state of each transformer in terms of maintenance and replacement to avoid equipment failure

B. Liquid Insulation	35%
B1. Dielectric Strength (D877)	Transformer Oil Analysis (TOA) condition codes
B2. Interfacial Tension	
B3. Acid Neutralization	
B4. Oil Moisture	
B5. Percent PF at 25C max	

**Transformer physical age**

F. Physical Condition	50%
F6. Age of Transformer	Age of Transformer

**Oil Tap Changer Analysis:**

<sup>1</sup> It should be noted that Health Indices today have evolved from previous iterations. This evolution makes it potentially misleading to compare today's health indices to those from previous years. This evolution is driven by SCE's continuous effort to improve its collection and analyzing of data.

The OTA process determines the condition of a Load-Tap Changer (LTC) without having to intrusively inspect the unit. It is an oil diagnostic test that evaluates dissolved gases in LTC oil. The benefits of the OTA process include:

- Increasing reliability of tap-changers
- Reducing current maintenance budget requirement
- Enhancing possibility of predicting failure modes earlier than time-based methods

G. Tapchanger	15%
G1. ARC / ARCSEL Compartment	Oil Tapchanger Analysis (OTA) condition codes
G2. VAC Compartment	
G3. SELSW 1 Compartment	
G4. SELSW 2 Compartment	

### Transformer repair history

H. Repair History	5%
H1. Annual PMA notifications	Notification Repair History against asset

### Subject Matter Expert evaluation

J. SME Evaluation	30%
J1. SME Evaluation	SME input of condition/Spare parts availability
J2. Spare Parts	

**Circuit Breaker Health Index** and Health Condition inputs and weights given to each input are as followed:

SF<sub>6</sub> gas purity checks for the direct affect:

- Performance of the circuit breaker
- High purity ensures better insulation properties
- Preventing electrical arcing enhancing circuit breakers ability to extinguish arc

### Oil Circuit Breaker Analysis (OCBA):

The OCBA process determines the condition of the internal components of an oil circuit breaker. The process incorporates an in-depth evaluation of the dissolved gases, metals, and particulates in the oil. The process to generate a work request to draw an oil sample is initiated by three specific triggers: the amount of time since the breaker was last sampled, the number of operations, or the number of fault operations. The benefits of the OBCA process include:

- Establishing future maintenance requirements based on condition
- Minimizing intrusive inspections
- Focusing on circuit breakers with problematic conditions

A. Insulation	20%
A1. Gas purity (SF6)	Purity of SF6 Gas (moisture, leak) OCBA condition code
A2. Gas moisture (SF6)	
A3. Gas leak quantity (SF6)	
A4. Gas leak occurrences (SF6)	
A5. OCBA test (Oil)	

Number of operations, timing test for Open/Close, measurements of general maintenance

B. Mechanism	65%
B2. Number of operations	Number of CB operations, timing test for Open/Close, measurements of general maintenance of CB
B3. Doble trip timing test	
B6. Mechanism	

Contact Resistance:

The contact resistance test (Ductor) is performed on all new circuit breakers during commissioning, after a close-in fault, on any suspect high voltage connections, and during routine maintenance

Overstress%:

The maximum calculated short circuit duty that could exceeds the interrupting rating of the corresponding circuit breaker

<b>C. HV Power Path</b>	<b>35%</b>
<b>C1. Contact resistance</b>	Contact resistance and Short
<b>C5. Overstress Percentage</b>	Circuit Duty Overstress %

Type of cubicle switch gear Indoor/Rackout/Metal Clad/Outdoor physical age of circuit breaker

<b>D. Structures and Enclosures</b>	<b>20%</b>
<b>D1. Indoor Switchrack</b>	CB type Indoor/Rackout/Metal Clad/Outdoor. Age of circuit breaker
<b>D2. Cubicle Rackout</b>	
<b>D3. Metal Clad Rackout</b>	
<b>D5. Outdoor CB in Closet</b>	
<b>D4. Age of Circuit Breaker</b>	

Circuit breaker repair history

<b>H. Repair History</b>	<b>5%</b>
<b>H1. Annual PMA notifications</b>	Notification Repair History against asset

Subject Matter Expert evaluation

<b>J. SME Evaluation</b>	<b>30%</b>
<b>J1. SME Evaluation</b>	SME input of condition/Spare parts availability
<b>J2. Spare Parts</b>	

The percentages shown in each of the tables above are referred to by SCE as “confidence percentages.” They indicate the level of confidence that each category of condition would lead to equipment degradation or failure. The health index also includes additional factors such as Weibull models for each transformer and circuit breaker asset type.

- b) SCE provides here the requested tables similar to Table V-20 (“Distribution of A and B Bank Power Transformers by Health Condition as of 2022 Year End”) and Table V-22 (“Circuit Breakers by Health Condition as of 2022 Year End”) in tabs entitled “Q2.b Power Transformers” and “Q2.b Circuit Breakers” of the attached document.
- c) SCE provides the requested tables similar to Table V-20 (“Distribution of A and B Bank Power Transformers by Health Condition as of 2022 Year End”) and Table V-22 (“Circuit Breakers by Health Condition as of 2022 Year End”) in the attached Excel File in the tabs entitled “Q2.c Power Transformers” and Q2.c Circuit Breakers” of the attached document.
- d.i) SCE provides the power transformer failure reports in the attached document”
- Power Transformer Failure Reports
- d.ii) SCE provides the available equipment asset age at time of failure, Dissolved Gas Analysis

(DGA) results, field test data, repair history, and historic (5 years prior) asset health condition (Very Good, Good etc.) for subject equipment in attached document:

- Power Transformer Failure Reports

iii) SCE provides B Bank Transformer Condition installations for 2018-2022 with age, condition, and health index in tab titled “Q2.d.iii Installed B Banks” of the attached document.

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 4 3**

**To: TURN**

**Prepared by: Myn Kim**

**Job Title: Senior Advisor**

**Received Date: 1/3/2024**

**Response Date: 1/17/2024**

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**Question 04.a-d:**

Refer to WP SCE-02, Vol. 05 “Substation Transformer Weibull Report” at pages 176-182 and “Substation Circuit Breaker Weibull Analysis” at pages 195-210:

a) Please provide underlying SAP data from 2016-2022 for transformer and circuit breaker Weibull reliability model(s).

b) Please give basis for assumption(s) behind Weibull (as opposed to other Cumulative Distribution Functions for failure probabilities), shape/scale parameters, rationale for 7-year historic timeseries, and whether (and which) other models were evaluated for the analyses.

c) Please provide Original Equipment Manufacturer (OEM) recommended MTBF (Mean Time Before Failure), MTTR (Mean Time To Repair) and EUL (End of Useful Life) parameters for Transformers (A,AA,B-type) and each of the 4 types of circuit breakers in pp. 177 and pp.196 respectively.

d) Please provide working Python (.py) file(s), including input data, to simulate the application of the Reliability Python Library for “Substation Transformer Weibull Report” and “Substation Circuit Breaker Weibull Analysis”. Please explain (with inline comments) how the error rates were calculated.

**Response to Question 04.a-d:**

a) SAP data from 2016-2022 for transformer and circuit breaker Weibull reliability model(s) is provided in:

TURN\_SCE\_043.Q.4.a SAP Data from 2016-2022 for XFMR\_CB Weibull.xlsx.

b) The Weibull distribution was selected to model the failure of equipment that tends to fail due to wear and tear and capable of accommodating a wide range of curve shapes with its two parameters. The shape and scale parameters were selected to fit the historical removals from 2016-2022, and that time horizon was selected as a balance of recency and sample size. Other models were not evaluated given the benefits of the Weibull distribution.

c) To SCE’s knowledge, manufacturers typically do not provide a recommendation for a MTTR, MTBF or EUL parameters. SCE typically provides the appropriate design standard for expected design life to the OEM. According to current industry standards, the design life expectancy for circuit breakers and transformers is 30 years. However, factors such as scale of operations, equipment load, and environment in which the equipment is operated affect the operational life.

d) The Python code and help files (reliability\_plots.py, readme.txt, requirements.txt) used in the verification process along with the input data files (CB.xlsx and TRF.xlsx) can be found in the

Reliability\_Plots\_Code.zip folder. The Excel model's output was verified against the Reliability Python Library[1] ensuring it generates a reasonable projection for equipment removal. The Python model was only used as part of the verification process, particularly in the comparative analysis, confirming the reliability of the Excel model's results and not used for the detailed calculations of each asset type and their voltage levels.

The errors were determined by comparing the Eta values from both, the Excel and Python models as noted on the below tables:

For Transformers:

<b>Type</b>	<b>Eta - Excel Model</b>	<b>Eta - Python</b>	<b>Error</b>
TRF	34.34	31.97	6.90%

For Circuit Breakers:

<b>Type</b>	<b>Eta - Excel Model</b>	<b>Eta - Python</b>	<b>Error</b>
Air Mag	59.28	57.94	2.26%
Gas	26.8	27.15	-1.31%
Vacuum	32.15	32.06	0.28%
Oil	58.16	57.35	1.39%

[1] M. Reid, "Reliability - a Python library for reliability engineering [ Computer Software] Version 0.8.2," [Online]. Available: <https://zenodo.org/record/3938000>.

*Southern California Edison*  
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**DATA REQUEST SET T U R N - S C E - 0 5 3**

**To: TURN**  
**Prepared by: Tony Huynh**  
**Job Title: Senior Advisor**  
**Received Date: 1/18/2024**

**Response Date: 2/1/2024**

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**Question 06.a-b:**

In Fig IV-32 “Time-dependent replacement rate curve”, SCE illustrates a long-term steady state replacement rate. In the associated text, SCE states that “modern technology tools, modeling, and analyses” enable SCE “to refine and optimize the way the transmission system is managed.” (page 70, lines 10-12). SCE also describes the approach it will take moving forward, “with scope starting in 2025.” (page 71, line 1).

a. Please identify and briefly explain each specific program, data analytics, and/or tool, if any, to be used to identify, prioritize and drive its TIR Replacement Activities starting in 2025. Please also identify and briefly explain the current programs, data analytics, and/or tools currently being used for these purposes, and how they are different than the scope starting in 2025.

b. Please provide data on current and historical ‘replacement rates’ for transmission infrastructure for each of the 6 programs in Section IV. Transmission Infrastructure Replacement (2018-present). Please explain what SCE expects as the steady-state replacement rate and an approximate timeline to reach long-term steady state rates.

**Response to Question 06.a-b:**

- a. The identification and explanation for each program within SCE’s Transmission Infrastructure Replacement (TIR) Program is described in Exhibit SCE-02, Volume 4 pp. 73-129.

As explained on pages 69-71 of Exhibit SCE-02, Volume 4, SCE is maturing a system-wide proactive approach in TIR to identify, prioritize, and execute its TIR activity decision making. Historically (pre-2025 starting activities), SCE did not leverage tools such as “predictive modeling” in prioritizing or selecting its TIR activities as SCE is planning to execute in 2025. Previously, these activities were largely driven through field observations by subject matter experts (SME) in localized areas.

Going forward, TIR activities involve, but are not limited to, analytics of the following data:

- SAP Master Data (i.e., historical, maintenance, repairs, notifications, work orders, cost, etc.)
- Outage

- Weather
- Wire-down
- Failure
- Equipment usage

The table below lists the current TIR programs identified in testimony and methodology (prioritization, scope selection, etc.)

<b>TIR Programs</b>	<b>Historical Methodology</b>	<b>Current/New Methodology</b>
Overhead Re-conductor Program (ORCP)	SME	SME, Data Analytics, Risk Analysis, Transmission Model
Line Rebuild Program	N/A – program did not exist	SME, Data Analytics, Risk Analysis, Transmission Model
Fault Return Conductor (FRC) Installation Program	SME	SME, Data Analytics, Risk Analysis, FRC Model
Switch Replacement Program	SME	SME, Data Analytics
Underground Cable Replacement Program	SME	SME, Data Analytics
Pothead Replacement Program	SME	SME, Data Analytics

- b. SCE objects to this data request on the basis that it is unduly burdensome and unreasonable, as SCE is not obligated to conduct new studies or analyses in response to data requests; rather the Commission’s discovery rules require SCE to produce existing, relevant data and information, to the extent that compiling and producing that information is not unduly burdensome. SCE also objects to the phrasing “Please explain what SCE expects” as vague and ambiguous. Without waiving the foregoing objections, SCE responds as follows:

The 2025-2028 TIR Program forecast is independent from historical TIR program “replacement rate.” SCE’s current system/methodology of recording TIR metrics is not set up at the equipment level (to capture “replacement rate”); instead, metrics are captured at the capital \$USD spend level. However, SCE can provide the recorded expenditures for the five (5) programs for years (2018-current).

Figure IV-32 page 70, The “Time-Dependent Replacement Curve”; depicting steady-state replacement rate and the approximate time to reach that steady state is theoretical. Until SCE is able to mature and analyze data from its TIR strategy implementation, SCE cannot provide the timeline to reach steady-state implementation of its TIR program and activities.

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 7 2**

**To: TURN**  
**Prepared by: Alysha Sanchez**  
**Job Title: Sr. Advisor**  
**Received Date: 1/25/2024**

**Response Date: 2/8/2024**

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**Question 01.a-b:**

Re. SCE-02, Vol. 01 Part 2, please refer to lines 12-14 on page 83: "... Therefore, going forward, the scope and approach for OCP will include all wire sizes, and prudently utilize covered conductor to address public safety and reliability risk..." Please provide:

- a. An Excel spreadsheet with "all wire sizes" (in AWG or similar) included in the new scope, broken down by wire-down events (# of events) by wire size and primary driver (i.e. Wire-to-Wire Contact, Vandalism / Theft, Undetermined Cause, CFO, Equipment Failure) for each year from 2013-2022.
- b. An Excel spreadsheet with "all wire sizes" (in AWG or similar) included in the new scope, broken down by data on safety (# of injuries, fatalities) and reliability (# of Customer Interruptions, Customer Minutes of Interruption, SAIDI) from 2013-2022.

**Response to Question 01.a-b:**

The circuits and circuit segments included in TURN-SCE-072 Question 01.a.xlsx are based on scope identified through the machine learning algorithm at the time of filing.

As noted in SCE's 2021 GRC, SCE prudently reallocated resources to address imminent wildfire threats. This reallocation resulted in material reductions in proactive infrastructure replacement (IR) activities in which SCE is proposing to normalize back to traditional levels in its 2025 GRC. Given this return to appropriate and traditional levels of IR work, SCE continues to mature and evolve its machine learning capabilities while examining the impacts of years of resource reallocation. As a result, SCE is reviewing previously scoped and/or deferred work as well as particular segments associated with past failures or known risks. While this review may result in the inclusion of different segments than those reflected in our point-in-time GRC filing, it does not impact SCE's overall proposed GRC forecast.

**Question 01.a:**

Please see TURN-SCE-072 Question 01.a.xlsx spreadsheet.

**Question 01.b:**

Please see TURN-SCE-072 Question 01.b.xlsx spreadsheet.

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 7 2**

**To: TURN**  
**Prepared by: Alysha Sanchez**  
**Job Title: Sr. Advisor**  
**Received Date: 1/25/2024**

**Response Date: 2/8/2024**

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**Question 03.a-f:**

Re. SCE-02, Vol. 01 Part 2, WPSCE02V01P2, pages 107-109, SCE describes the development of Overhead Conductor Program (OCP) Scope, stating:

“...The program scope was informed by a machine learning algorithm utilizing a multitude of mechanical, electrical, and environmental attributes to estimate the risk and consequence of failure for each of the 500,000+ primary overhead conductor segments on the SCE distribution system. The output of the algorithm was then used to select 1,680 of the higher risk circuit miles population for replacement...”

- a. Please explain the difference between the 500,000+ primary overhead conductor segments mentioned above, and the 1,680 Circuit Miles population predicted for replacement. Please describe how conductor segments correspond with circuit miles and vice versa.
- b. Please provide details of the specific ML model used for the Overhead Conductor Program, including but not limited to the basis for selection, other ML models considered (if any), model selection metrics used (if any), and input variables (mechanical, electrical, environmental, and operational attributes, with corresponding weights).
- c. Please specify each outcome variable and (regression) equation for the ML model.
- d. For input variables used in the final model, please specify the feature importance of each variable predicting the model output.
- e. Please provide relevant accuracy / precision metrics and a narrative explanation describing model performance.
- f. Please refer to page 108 Section V. Outputs of the Distribution Risk Model. Please describe columns “Safety and Reliability Risk Reduction %”, “Remaining Safety and Reliability Risk %” and “Expected SAIDI Reduction” and explain how those outputs are calculated by the model.

**Response to Question 03.a-f:**

**Question 03.a:**

Conductor segments are spans of OH conductor that connect one piece of electrical equipment to another. In practice, this means structure with equipment to a structure with equipment. Since circuits exist in varying terrain and neighborhoods to serve the specific needs of customers and communities in different locales, conductor segments can vary in length from a few feet to a few miles. The total population of OCP eligible segments is represented by the 500,000+ primary OH conductor segments in SCE’s service area. This corresponds to approximately 30,000 circuit miles of primary OH conductor outside of HFRA.

The 2025-2028 OCP scope represents 34,588 primary OH conductor segments, which equates to 1,680 circuit miles. This scope represents approximately 6 percent of SCE’s total population of primary OH conductor outside of HFRA.

The table below breaks down circuit segments to circuit miles for OH primary distribution circuits.

Conductor Segments to Circuit Miles Breakdown		
Primary OH Distribution Segments	Approximate Primary Distribution OH Circuit Miles	Description
700,000+ circuit segments	~40,000 circuit miles	All OH Primary Distribution
500,000+ circuit segments	~30,000 Non-HFRA circuit miles	Eligible OH Primary Distribution for OCP Scope
	~1,500 HFRA circuit miles	
34,588 circuit segments	1,680 circuit miles	2025-2028 OCP scope

**Question 03.b:**

The OH Conductor model predicts the probability of failure for distribution primary overhead conductor using Random Forest—a Machine Learning technique—with two sub-models, i.e., EFF (equipment facility failure) Conductor and CFO (contact with foreign object).

**EFF Conductor sub-model:**

The EFF Conductor sub-model is a binary classification model. The EFF Conductor component predicts the probability of a conductor failure.

**CFO sub-model:**

The CFO sub-model is a multi-classification model. The CFO component predicts the probability of a conductor failing because of contact with a particular type of foreign object, i.e., animal, vegetation, balloon, vehicle, unknown, and others. This multi-classification model is one approach to determine different failure probabilities for each sub-driver.

**Other models:**

Other model algorithms were considered such as gradient boosting and neural networks but there was no appreciable accuracy improvement.

The Receiver Operating Characteristic (ROC) and Area Under the Curve (AUC) described in the response to TURN-SCE-072 question 2a are the same metrics that are used to determine model algorithm selection, feature selection, and hyperparameter tuning. Input features are included in the feature importance plots provided in the response to question 3d.

The decision trees that constitute the random forest are statistically generated; neither data scientists nor engineers force any weights on individual features. The decision thresholds are set by the algorithm in a manner that maximizes the variance between the two classes being modeled, for the particular bootstrap sample being trained.

**Question 03.c:**

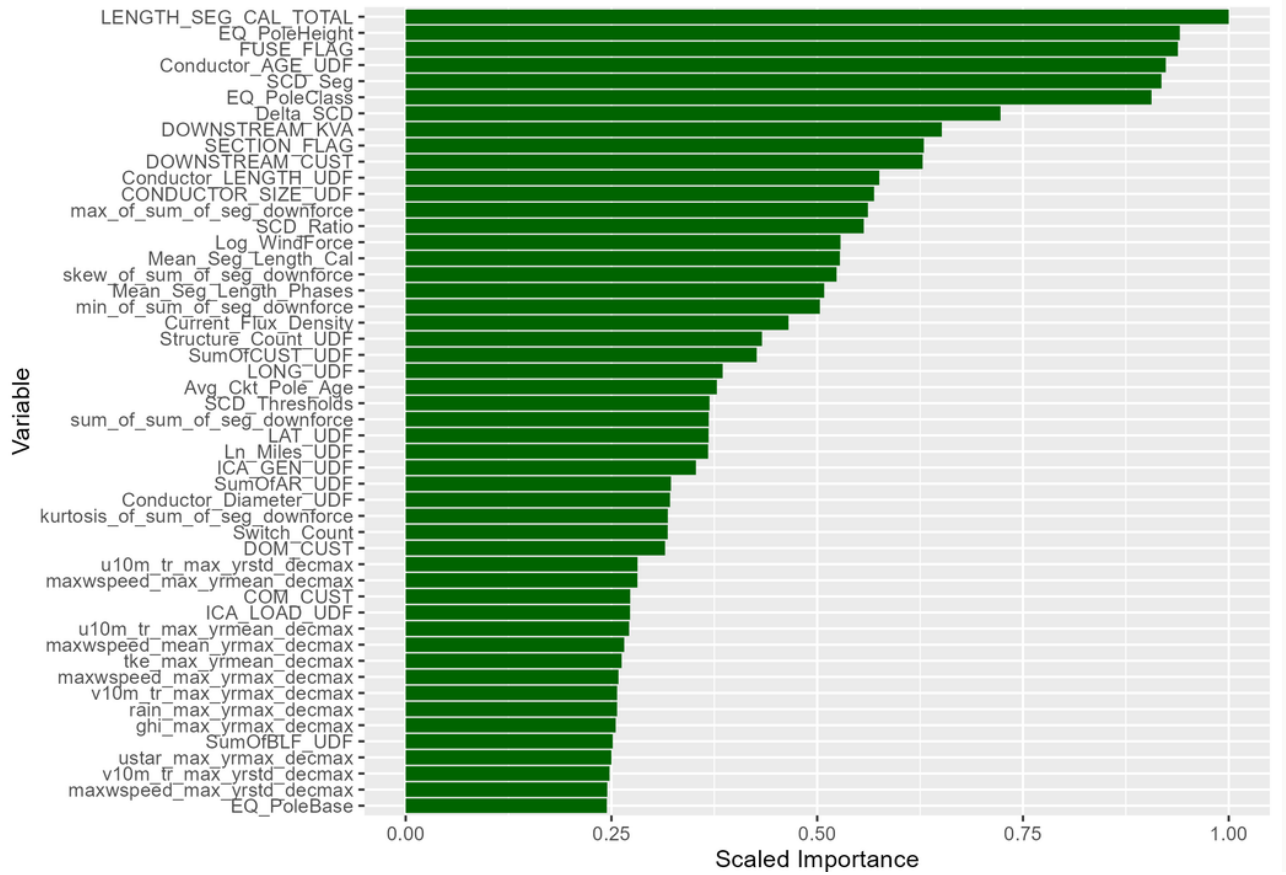
The output of all of SCE's machine learning models is probability of failure for a given asset within an asset class. The random forest algorithm statistically determines the probability based on constructing a collection or "ensemble" of decision trees. These decision trees are constructed by taking multiple bootstrap samples from historical data. For prediction, each of these decision trees casts a "vote" for whether an asset was a part of the failing or passing class in their bootstrapped data set. Due to the random sampling and sub-setting of data used for decision tree creation and because these trees create decision boundaries across many different variables, the ML model does not have a smooth, continuous functional representation.

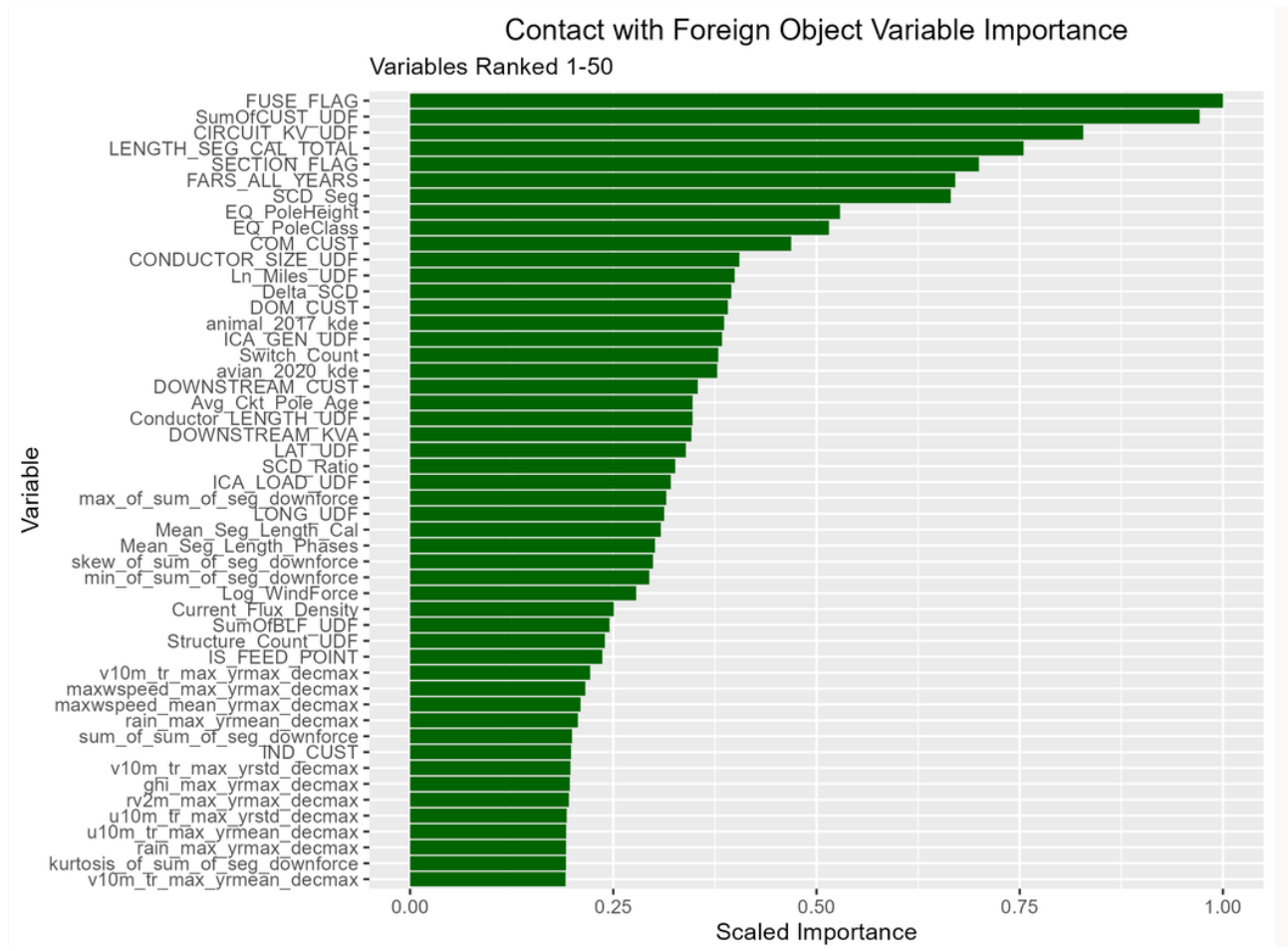
**Question 03.d:**

The two charts below illustrate the feature importance of each variable for the EFF model and the CFO model.

### Equipment Facility Failure Variable Importance

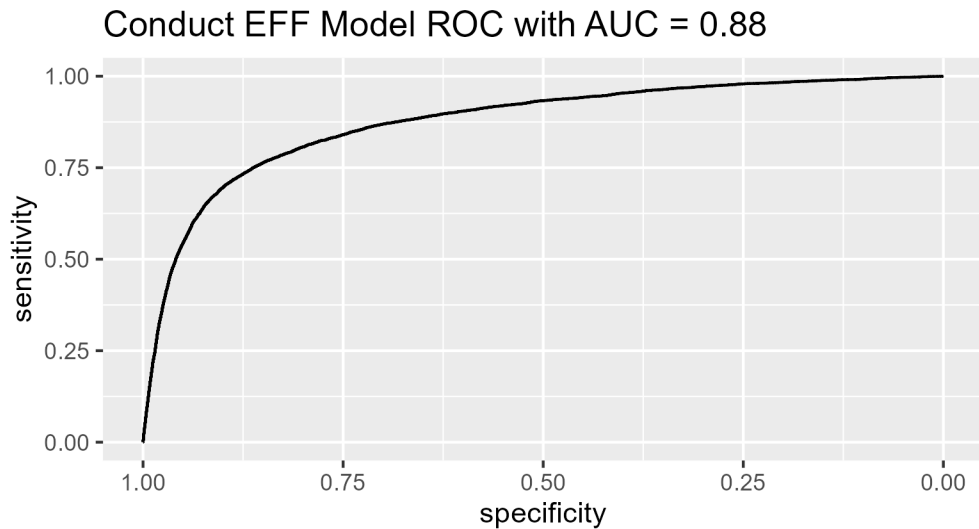
Variables Ranked 1-50





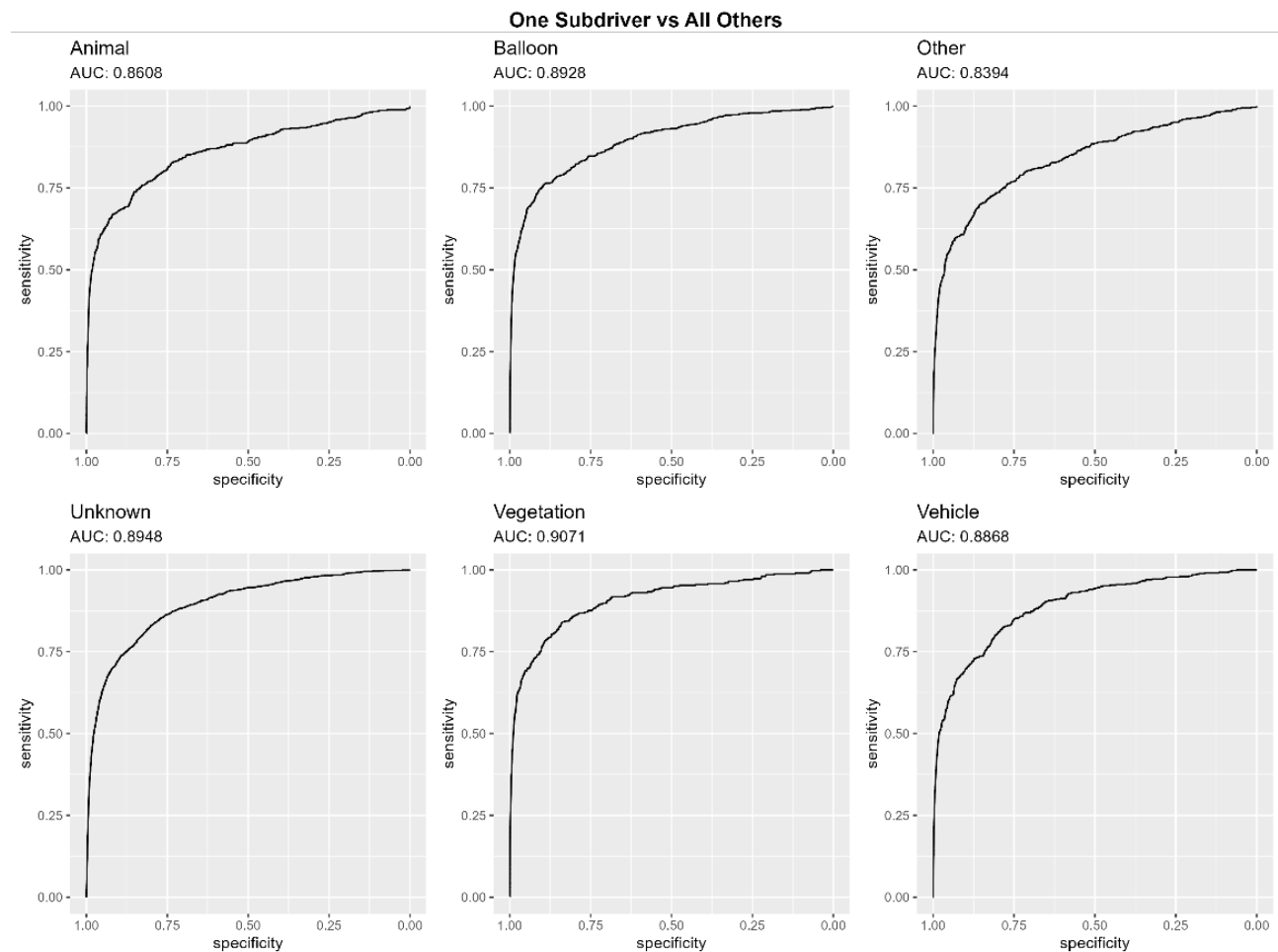
**Question 03.e:**

The EFF model is a binary classification model with an AUC of 0.88



The CFO model is a 6-way multilabel classification model; e.g. six separate binary classification models with the following AUC values:

- Animal: 0.86
- Balloon: 0.89
- Other: 0.84
- Unknown: 0.89
- Vegetation: 0.91
- Vehicle: 0.89



An explanation of ROC curves and AUC is given in the response to 2a. All submodels used in the OCP are well above 0.8 AUC.

### **Question 03.f:**

The Safety & Reliability Risk Reduction Percentage is the sum of the MARS Risk Reduction for the 1,680 scope miles divided by the total MARS risk score for the total population of OCP-eligible segments in SCE territory.  $B / C = D$

A	B	C	D
Circuit Length (in miles)	MARS Risk Reduction	Total MARS Risk in Population	Safety & Reliability Risk Reduction Percentage
1,680	0.893329	3.104029	29%

Remaining risk is determined by taking the total risk percentage and subtracting the risk reduced (100% total risk - 29% risk reduction = 71% remaining risk)

Year	Circuit Miles Length (in Miles) <sup>3</sup>	Safety & Reliability Risk Reduction %	Remaining Safety & Reliability Risk %	Remaining Risk Calculation Description
2025	420	12%	88%	=100% Total Risk - 12% Risk Reduced
2026	420	7%	81%	=88% Remaining Risk - 7% Risk Reduced
2027	420	5%	75%	=81% Remaining risk - 5% Risk Reduced (with rounding)
2028	420	5%	71%	=76% Remaining Risk - 5% Risk Reduced (with rounding)
	1,680	29%	71%	

The expected System Average Interruption Duration Index (SAIDI) is proportional to the product of frequency of failure and expected Customer Minutes Interrupted (CMI) were a segment to fail. The reduction in SAIDI is due to the reduction of the frequency of failure attributed to the mitigation effectiveness. The reliability consequence before and after mitigation are unchanged. The SAIDI improvement is attributed completely to the reduction in the likelihood of failure due to the specific mitigation chosen.

While gathering the data for this request, SCE identified in the work paper on page 108 Section V. Outputs of the Distribution Risk Model, SCE has 5.6 reduction minutes for 2025 and 3.3 reduction minutes for 2026. These were inputted incorrectly; they should be 5.7 reduction minutes for 2025 and 3.4 reduction minutes for 2026. This increases the overall reduction in SAIDI from 13.8 minutes to 14.1 minutes.

Year	Expected SAIDI 420 circuit miles per year	Delta Reduction in Minutes
2025	40.2	5.7
2026	36.7	3.4
2027	34.0	2.7
2028	31.7	2.3
		14.1

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 7 2**

**To: TURN**  
**Prepared by: Alysha Sanchez**  
**Job Title: Sr. Advisor**  
**Received Date: 1/25/2024**

**Response Date: 2/8/2024**

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**Question 04.a-c:**

Re. SCE-02, Vol. 01 Part 2 (page 85), lines 9-11: "... Protection equipment is installed on distribution circuits to detect fault conditions and de-energize the lines. However, depending on the type of fault and the specific circuit configuration, lines are not always de-energized when wire-down events occur..." At footnote 112 of the same page, SCE defines wire-down events as "...A primary distribution wire-down is defined as a primary overhead conductor that is broken and has fallen from its intended position, or it has fallen within eight feet of the ground or lower."

a. Please describe the type of fault and specific circuit configurations under which a wire-down event would not initiate tripping of the overhead protection device, or trigger an alarm. Please cite specific examples if applicable.

b. Please provide an Excel worksheet with the annual frequency of occurrence of wire-down events (from 2013-2022) broken down by a) events with fallen conductor within 8 ft., b) events with fallen conductor above 8ft. from ground (as described in the definition of a wire-down event), c) events that resulted in an energized conductor and d) wire-down events that resulted in a deenergized conductor. If such classification(s) do not exist, explain why not.

c. Please describe if SCE has employed technological or maintenance tools between 2013-2022 to avoid situations with injury potential described in a) and b) above.

**Response to Question 04.a-c:**

**Question 04.a:**

In general, the typical reason for a distribution wire-down event not initiating the tripping of an overhead protection device is that the associated fault does not generate sufficient fault current for protection devices to operate. This can happen for any circuit configuration when the wire makes physical contact with a high-impedance surface, such as asphalt, or when the wire down has fallen lower than 8 feet from the ground but has not made physical contact with the ground.

There are also circuit configurations where, based on the specific location of the wire-down event, the system impedance itself can limit the amount of fault current even if the wire makes contact with the ground. As one example, if a circuit has phase-to-phase connected transformers and a wire-down event specifically occurs on the "load side" of one phase, the amount of fault current can be reduced. On a related note, this particular scenario was analyzed in SCE's "Covered Conductor Compendium" published in 2018. On pages 44-48 of this Compendium, SCE presented both

simulation and laboratory testing results performed by NEETRAC as a safety comparison of one specific “line-side” versus “load-side” wire down modeled scenario. The conclusion of these tests, summarized on page 48 of the Compendium, showed how covered conductor is superior to bare conductor for both line-side and load-side faults. The Covered Conductor Compendium is available on SCE’s website (<https://www.sce.com/safety/wild-fire-mitigation>) under the “supporting documents” drop-down within the 2023-2025 WMP section.

In terms of alarms, SCE’s Meter Alarm of Down Energized Conductor (MADEC) system is a system that SCE put into place in 2019 that utilizes smart meter data to detect a subset of energized wire-downs as well as other high impedance faults or hazards. MADEC is able to detect several types but not all types of energized wire-down events; for example, MADEC is generally not able to detect wire down events where the wire falls lower than 8 feet but does not come into contact with the ground. As another example, one known circuit configuration difficult for MADEC to detect wires down is the case of single-phase radials with phase-to-neutral connected transformers. In this configuration, it is generally more difficult because wires down on single phase radials are difficult to distinguish between outage events and wires-down events based on meter data alone.

#### **Question 04.b:**

SCE is developing the ability to parse out events into “hit ground” or “did not hit ground” for future reporting. SCE is focused on the safety concerns associated when a wire-down incident occurs, regardless of whether the wire physically makes contact with the ground. A wire-down that does not touch the ground still poses tangible danger to the public and to our workers.

The table below and the attached file entitled “TURN-SCE-072 Question 04.b.xlsx” provides the percentage of wire-down events not resulting in automatic de-energization. SCE is not able to provide this information prior to 2020. SCE has attempted in the past to document whether a wire down is energized. Wire down data is documented by field personnel who are first to arrive on-scene. Documenting whether a wire down was energized at the time it initially came down based on observations in the field is rather subjective, particularly if that wire is not energized when responders arrive (even if it may have been energized when it initially became a wire down). Furthermore, it can be nearly impossible to determine when the conductor struck the ground relative to when the circuit relayed (i.e., de-energized). SCE has recently studied a sample of events for a limited time period to determine the rate of energized wire-down events. SCE found the process to be resource-intensive and to produce results with an unknown degree of accuracy.

Distribution Monthly Historical Data:													
Date	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Totals
2020	9.2%	4.6%	9.4%	14.3%	15.1%	16.9%	16.9%	24.1%	16.5%	23.8%	26.5%	16.7%	17%
2021	16.0%	23.6%	13.3%	17.6%	16.5%	11.4%	25.0%	21.5%	24.4%	20.5%	22.5%	16.7%	19.0%
2022	33.3%	44.0%	40.0%	44.4%	47.6%	48.8%	40.3%	34.9%	36.6%	35.7%	41.9%	46.0%	41.1%
Average by Month	19.5%	24.1%	20.9%	25.4%	26.4%	25.7%	27.4%	26.8%	25.8%	26.7%	30.3%	26.5%	25.6%

In 2020 and 2021, SCE used information from our MADEC algorithm to estimate if a wire-down event was automatically de-energized. Under this methodology, the wire-down was determined to be energized if multiple low-voltage alarms from multiple meters came in around the time/location of the wire down event. This methodology identified a wire as energized where it was 100% confirmed the downed wire was energized. However, there may be some events that SCE could not 100% confirm if the down wires were energized.

In 2022, SCE altered our methodology to provide a more conservative view of the number of energized wire-down events. SCE felt this is prudent due to the public safety risk around these events. Under the more conservative methodology, a wire down is considered not energized only when no low voltage alarms on any meters come in around the time of the wire down on the subject circuit(s). This methodology identifies a non-energized wire down only where it was 100% confirmed the wire-down was not energized. Similar to the above methodology, the percentage of energized events is not simply 1 – the percent of de-energized events since there may be some events that SCE could not 100% confirm if it was de-energized that actually were energized. However, for reporting purposes SCE calculates the number of energized events as 1 – the percent of de-energized events because that is a prudent and conservative way to perform the calculation.

**Question 04.c:**

SCE continuously looks at ways to mitigate the risks electrical equipment poses to the general public and employees. One example is SCE's MADEC system. In the case of a wire down event where wires have struck the ground, SCE's MADEC system is a machine learning algorithm utilizing smart meter data to detect a subset of energized wire-downs as well as other high-impedance faults or hazards. In the event of an energized wire down where the wire is on the ground or in contact with another grounded object, for the events where the meters on that portion of the circuit exhibit the characteristics of an energized wire-down event, MADEC is able to generate an alarm that allows an operator to act quickly and de-energize a circuit even if the protective device did not operate.

*Southern California Edison*  
*A.23-05-010 – SCE 2025 GRC*

**DATA REQUEST SET T U R N - S C E - 0 7 2**

**To: TURN**  
**Prepared by: Alysha Sanchez**  
**Job Title: Sr. Advisor**  
**Received Date: 1/25/2024**

**Response Date: 2/8/2024**

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**Question 05.a-c:**

Re. SCE-02, Vol. 01 Part 2 (page 88) Figure II-42 and Table II-22 on reliability metrics for outages caused by Overhead Equipment (OH):

- a. Please provide an Excel spreadsheet with historical SAIDI, SAIFI, MAIFI, and CAIDI data for “OH equipment” from 2013-2022, with all interruptions included.
- b. Please provide an Excel spreadsheet with historical SAIDI, SAIFI, MAIFI, and CAIDI data for “OH equipment” from 2013-2022, with major event days excluded.
- c. For the pie chart on the right for “OH Equipment” in Figure II-42, please explain what is meant by “Conductor / Splice / Connector / Tap” vs. “Other OH equipment”. What would the contribution to SAIDI be for OH Conductor only (excluding Splice / Connector / Tap)?

**Response to Question 05.a-c:**

**Question 05.a:**

Please see the attached file, “TURN-SCE-072 Question 05.a.xlsx”. This spreadsheet includes all OH distribution outages with the Cause Description of “OH Equipment”.

**Question 05.b:**

Please see the attached file, “TURN-SCE-072 Question 05.b.xlsx”. This spreadsheet includes all OH distribution outages with the Cause Description of “OH Equipment” excluding Major Event Days (MED).

**Question 05.c:**

“Splice/Connector/Tap” are ancillary equipment that are used in conjunction with overhead conductors to make necessary connections to other devices. All these ancillary devices that are connected to the OH conductor would be replaced as part of OCP. “Other OH equipment” could be switches, transformers, capacitor banks.

Figure II-42 illustrates the distribution of overhead equipment failures. Among these failures, 9% are attributed to conductor/splice/connector/tap, while the remaining 7% fall under the category of other overhead equipment.

Breaking down the conductor/splice/connector/tap failures further:

- Conductor failures account for 7%.
- Splice/Connector/Tap failures make up 3%.

<b>Cause Description Detail</b>	<b>Percentage of Overhead Equipment Failure SAIDI</b>
<b>Conductor / Splice / Connector / Tap</b>	<b>9%</b>
Conductor	7%
Splice/Connector/Tap	3%
<b>Other Overhead Equipment</b>	<b>7%</b>
<b>Overhead Equipment Failures</b>	<b>16%</b>