FINAL

# 2020 TRANSMISSION MAINTENANCE AND COMPLIANCE REVIEW (TMCR) REPORT

SOUTHERN CALIFORNIA EDISON®
Energy for What's Ahead®

## Foreword to *Final* 2020 TMCR Report

This represents SCE's Final 2020 TMCR Report. SCE would like to thank those who participated in SCE's 2020 TMCR stakeholder process for your review of the Draft 2020 TMCR Report. SCE appreciates comments provided by the CPUC on the Draft 2020 TMCR Report. SCE's responses to comments it received on the Draft 2020 TMCR Report are included in a new Appendix C. SCE has also revised Appendix B and the body of the TMCR Report to reflect the re-naming of the Transmission IR section to include Transmission Capital Maintenance. Additionally, SCE has made some changes to the Transmission Deteriorated Pole Program. Stakeholders have an opportunity to submit comments on this Final 2020 TMCR Report by October 13, 2020.

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# I. Executive Summary

Pursuant to Appendix XI of Southern California Edison's (SCE's) Transmission Owner Tariff (TOT), SCE's 2020 Transmission Maintenance and Compliance Review (TMCR) Report is part of SCE's annual public stakeholder process to provide additional transparency regarding transmission capital expenditures[1]. These expenditures predominantly relate to maintenance and regulatory compliance requirements to operate a safe and reliable transmission system. This work involves replacing aging infrastructure, repairing and maintaining equipment in accordance with compliance requirements, upgrading transmission facilities owned by others for which SCE has a contractual entitlement, mitigating the impact of wildfire, and securing its assets and facilities from seismic and security concerns.

As defined by SCE's TOT, the TMCR represents a specific scope of work on SCE's transmission system. Transmission projects reviewed by the California Independent System Operator Corporation (CAISO) pursuant to its tariff are not in scope for SCE's TMCR stakeholder process. Other exemptions to the TMCR process include: (1) facilities or projects that require an in-service date less than two years after their need being identified; (2) facilities or projects (a) that have less than 30% of their total individual capital costs included in SCE's wholesale transmission rate base and (b) where the Federal Energy Regulatory Commission (FERC) jurisdictional portion of the project's estimated individual cost is less than $1 million; and (3) facilities or projects that address the physical security and cyber security needs of the transmission system.

[1] TMCR will be suspended and a new Stakeholder Review Process (SRP) will be in place for 2021. The matter of SRP was approved by the Federal Energy Regulatory Commission on September 23, 2020.

SCE's TMCR process does not impact or restrict any stakeholder's Section 206 rights or right to intervene and/or protest in any of SCE's regulatory proceedings, including SCE's transmission rate filings.

This 2020 TMCR Report covers the years 2022-2024 and organizes investments into six categories: "Compliance," "Infrastructure Replacement and Capital Maintenance," "Wildfire Management," "Work Performed by Operating Agent," "Operations Support," and "Physical/Cyber Security."

## II. Introduction

California is at the forefront in the adoption of significant energy-related measures to address climate change and air pollution. Over the course of the past two decades, the state's legislature has taken action to implement initiatives aimed at reducing Greenhouse Gas (GHG) emissions. In this setting, SCE has developed various initiatives to decarbonize electricity, electrify buildings, electrify transportation, and promote the use of low carbon fuels. These separate but related initiatives are being pursued to achieve the spectrum of California policy measures aimed at improving air quality state-wide. Such measures include the establishment, in Senate Bill (SB) 350, of a Renewable Portfolio Standard (RPS) of 50% by 2030; the codification, in SB 32, of a GHG target to reduce emissions to 40% below 1990 levels by 2030; and the establishment, in Executive Order S-3-05, of a GHG target to reduce emissions to 80% below 1990 levels by 2050. SB 100 increases the RPS to 60% by 2030 and requires all of the state's electricity to come from carbon-free resources by

2045. SCE is committed to this clean energy future and embraces its role as a leader in the energy industry to reduce GHG emissions.

In addition to its commitment to a clean energy future, SCE prioritizes its efforts to increase the resiliency of its transmission grid which has become more vulnerable due to both the increased frequency and intensity of wildfires in recent years. SB 901 requires utility companies to create a Wildfire Mitigation Plan that details how they will build, maintain, and operate their electrical grid in a manner that reduces wildfire risk. In compliance with SB 901, SCE is committed to protecting public safety by hardening SCE's electric system against wildfires to improve system resiliency, among other mitigating measures. In this 2020 TMCR Report, SCE includes a new wildfire management section which addresses SCE's wildfire mitigation efforts that meet the TMCR threshold.

The state's ambitious energy policy goals require a robust and well-maintained electric grid, which requires capital expenditures to maintain reliability and to meet compliance requirements. In this light, SCE undertakes an annual TMCR process to identify predominantly transmission maintenance and compliance projects to maintain the safe and reliable operation of its electrical grid. This review provides stakeholders with an open, coordinated and transparent process for consideration of SCE's projects and activities, which inform the development of SCE's annual transmission rates. The annual process culminates with the publication of a final TMCR Report.

## III. TMCR Process Overview

The annual TMCR shares information about proposed SCE transmission facilities and projects that will have capital costs included in SCE's wholesale transmission rate base.[2] Projects within the scope of TMCR may include addressing compliance issues, replacing aging infrastructure, upgrading transmission facilities owned by non-Participating Transmission Owners (PTOs) for which SCE has a contractual entitlement, and securing assets or facilities from seismic or security concerns. SCE organizes these projects into the following categories: "Compliance," "Infrastructure Replacement and Capital Maintenance," "Wildfire Mitigation," "Work Performed by Operating Agent," "Operations Support," and "Physical/Cyber Security." Each TMCR provides the basic methodology, criteria, and processes used for determining and including projects in the TMCR Report. The report also includes estimated projected costs for the facilities or projects.

Pursuant to Appendix XI to the TOT, the following projects or facilities are outside the scope of the TMCR: (1) facilities or projects that are or would be identified through the California Independent System Operator's transmission planning process or generation interconnection process, including SCE's Wholesale Distribution Access Tariff interconnection processes; (2) facilities or projects that require an in-service date less than two years after their need being identified; (3) facilities or projects that (a) have less than 30% of their total individual capital costs included in SCE's wholesale

[2] Each TMCR describes transmission facilities or solutions to address identified needs in the second, third, and fourth years after its release. For example, the TMCR released in 2020 describes projects forecasted for years 2022, 2023 & 2024 and the reasons for such projects. Projects that are less than two years from their projected in-service date will not be included in the TMCR.

transmission rate base and (b) where the FERC-jurisdictional portion of the project's estimated individual cost is less than $1 million; and (4) facilities or projects that address the physical and cyber security needs of the transmission system. While the annual TMCR does not address the project-specific physical and cyber security needs of SCE's transmission system, SCE does provide aggregate cost information for such projects.

The TMCR is open to all interested stakeholders.[3] Pursuant to Appendix XI to the TOT, SCE must release a draft TMCR Report by May 15 each calendar year and provide stakeholders an opportunity to review the draft. SCE will then host a stakeholder meeting to review the TMCR Report with interested parties and the parties will have an opportunity to pose questions, offer suggestions, or raise concerns directly with SCE. Stakeholders may submit written comments regarding the draft report and items covered during the stakeholder meeting not later than 30 business days after the date of the stakeholder meeting. No later than 10 days after the comment deadline, SCE will post all timely received comments. After reviewing and considering comments, SCE will release a final TMCR Report no later than 45 days after the deadline for stakeholder comments. As appropriate, SCE may modify the final TMCR Report to include revisions in light of stakeholder comments or other related developments. The TMCR Report is not subject to CAISO approval.

[3] Pursuant to Section IV of Appendix XI, any Critical Energy Infrastructure Information ("CEII") or otherwise confidential and/or proprietary information provided pursuant to the Transmission Maintenance and Compliance Review shall be subject to non-disclosure agreements and other procedures provided by SCE.

## IV. TMCR Operational Plan

During the second quarter of each year, SCE commences its operational and budget planning process. The operational plans provide an estimated spend over the next 5 years. Specifically, they include a more detailed look at the work identified for the next 1-2 years and forecasts for years 3-5. Many factors are considered as the work plans and forecasts are developed, including safety, risk mitigation, compliance, and operational performance. SCE's budgeting and forecasting strategy varies based upon the work activity. Some operating plans use an aggregated historical average to derive the estimate while others use a bottom-up approach, where a list of projects/facilities are prioritized and slated to be replaced in a given year. Once the operating plans are developed, SCE management follows a structured approval process prior to submission.

The details of the operational plans are consolidated into the Integrated Work Plan (IWP), which is an operational tool that is designed to manage the consolidation of capital project information used to coordinate planned work for Substation and Bulk Transmission projects (ISO and non-ISO). As projects progress through their life cycle, substantive changes to scope, schedule, and budget are also managed by the change control process. The IWP database does not track actual costs or operating dates (ODs), but is used to provide a snapshot of forecasted costs and operating dates over the next five years, which may be revised throughout the calendar year.

Regarding TMCR governance, SCE management meets several times during the year to forecast a five-year workload. SCE identifies projects and programs as part of SCE's management process. Throughout this 2020 TMCR, SCE provides details relating to criteria and methodologies that inform SCE's mitigation plans, such as health index models, system topology and subject-matter expertise. This information outlines the factors SCE considers when determining where it is most appropriate to deploy resources. Note that these details will evolve in the future as SCE matures its asset and risk management practices.

## A. 2022-2024 TMCR Forecast

SCE organizes its TMCR forecast into six categories: Compliance; Infrastructure Replacement and Capital Maintenance; Wildfire Management; Work Performed by Operating Agent; Operations Support; and Physical Security. The forecasts for these categories are:

***Table IV-1***
***Estimated Total TMCR Capital Spend for 2022, 2023, and 2024 ($Thousand)***

| *AS OF 05/2020* | 2022 FORECAST | 2023 FORECAST | 2024 FORECAST | TOTAL |
|---|---|---|---|---|
| **TOTAL TMCR REPORT FORECAST** | **$250,970** | **$351,117** | **$386,618** | **$1,065,271** |
| **COMPLIANCE** | $115,343 | $216,831 | $269,885 | $602,060 |
| **INFRASTRUCTURE REPLACEMENT AND CAPITAL MAINTENANCE** | $90,624 | $86,808 | $70,398 | $247,831 |
| **WILDFIRE MANAGEMENT** | $1,961 | $2,255 | $1,889 | $6,104 |
| **WORK PERF. BY OP. AGENT** | $2,321 | $1,232 | $1,267 | $4,820 |
| **OPERATIONS SUPPORT** | $14,322 | $14,440 | $22,561 | $51,324 |
| **PHYSICAL SECURITY** | $26,400 | $29,550 | $20,617 | $76,566 |

Each category is explained in more detail below.

# V. 2020 TMCR REPORT'S MAIN CATEGORIES

## A. Compliance

This category includes electric transmission projects that are needed to meet the compliance requirements—set forth by the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), the California Public Utilities Commission (CPUC), or other agencies—for existing electric transmission infrastructure. Transmission Line Rating Remediation (TLRR) and Disturbance Monitoring (Phasor Measurement System Installations) are the only projects within the compliance category with forecast capital expenditures that meet the threshold for the years covered in this 2020 TMCR Report. SCE has also included a description of its Transmission Deteriorated Pole Replacement program, which is part of its compliance efforts but does not have forecast capital expenditures that meet the threshold for inclusion in this TMCR report.

***Table V-1***
***COMPLIANCE***

| | 2022 Forecast ($ Thousand) | 2023 Forecast ($ Thousand) | 2024 Forecast ($ Thousand) | Total ($ Thousand) |
|---|---|---|---|---|
| **Total** | **$115,343** | **$216,831** | **$269,885** | **$602,060** |
| **Transmission Line Rating Remediation (TLRR)** | $113,327 | $216,381 | $269,671 | $599,378 |
| **Disturbance Monitoring (Phasor)** | $2,017 | $451 | $214 | $2,682 |

### 1. Transmission Line Rating Remediation (TLRR)

#### a. Program Description and Criteria

SCE conducted a rating assessment of its CAISO controlled and 115kV radial lines built before 2005 to identify spans potentially not meeting CPUC's General Order (GO) 95 clearance requirements under certain operating and atmospheric conditions. SCE committed to NERC/WECC to remediate all identified potential clearance issues for the CAISO controlled facilities by 2025 and the 115 kV radial lines by 2030. While not its original intent, to the extent this remediation program reduces risk related to transmission line discrepancies in High Fire Risk Areas (HFRA), it has important secondary wildfire risk mitigation benefits.

A Light Detection and Ranging (LiDAR) study was conducted to identify transmission lines potentially in violation of GO 95 Table 1 and Table 2 clearance requirements,[4] which included building industry standard Power Line Systems-Computer Aided Design and Drafting (PLS-CADD) three-dimensional models to analyze each line for potential clearance discrepancies. Based on the results of the LiDAR study, SCE prioritized the transmission line discrepancies based on criteria such as line sag when operating at or above 130 degrees Fahrenheit and potential risk to public safety and system reliability based on location of span, terrain, encroachment type, and extent of deviation from standards.

The expected ramp up in 2023 is due in part to the TLRR licensing projects, which are typically larger in scope, that are expected to start construction

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[4] Available at http://www.cpuc.ca.gov/gos/GO95/go_95_table_1.html and https://www.cpuc.ca.gov/gos/GO95/go_95_table_2.html.

during this time period. The licensed projects are the Eldorado-Pisgah-Lugo, Ivanpah-Control, and Control-Silver Peak projects.

b. Methodology

SCE has taken a programmatic approach to the remediation work by utilizing new technologies and construction methods to minimize overall project impacts. Aligning scope with other programs and initiatives minimizes redundant work, outage impacts, and resource constraints. Initially, the program prioritized discrepancies into six levels and the focus was to remediate in order of highest priority. A discrepancy is any condition found in the field requiring remediation to meet GO 95 requirements during peak loading conditions. Currently, all discrepancies are evaluated on an entire circuit basis to allow for a holistic and effective remediation strategy. There are two major categories of discrepancies SCE is mitigating: (1) Bulk Transmission – 500kV and 220kV; and (2) Subtransmission – 161kV, 115kV, 66kV, and 55kV. The following factors are considered when reviewing the discrepancies:

- Geographic proximity and bundling of projects for construction efficiencies;
- Government land or land agency overlap;
- Permitting similarities and schedule impacts;
- Engineering design;
- Construction methods;
- Outage opportunities or restrictions with other TLRR and SCE projects;
- Material and procurement efficiency;
- Potential of remediating by working on a lower voltage; and

- Aligning scope with other programs and initiatives to minimize redundant work, outage impacts and resource constraints.

Each project is also reviewed under CPUC GO 131-D, which defines the rules relating to the planning and construction of electric facilities. Some projects fall under the exemptions listed in GO 131-D Section III.B.1 while others will require full permitting and become licensing projects. The following corrective actions have been identified for majority of the discrepancies:

- Reconductor;
- Structure replacement;
- Structure raises;
- Retensioning;
- Reframing;
- Adding an interset structure;
- Lowering or relocating subtransmission or distribution;
- Grading; or
- Lowering/removing object (such as a light pole).

## 2. Disturbance Monitoring (Phasor Measurement System Installations)

### a. Program Description and Criteria

NERC requires each Transmission Owner to install Disturbance Monitoring Equipment (DME) and report on disturbance data to facilitate analysis of events and verify system models.  Each Transmission Owner must have adequate data available to facilitate analysis of Bulk Electric System (BES) disturbances. SCE installs Digital Fault Recorders (DFR) and Phasor Measurement Unit (PMU) devices for post event analysis, situational awareness, and for use with mis-operation investigations. PMUs are installed in all 500kV substations, select 220kV substations that have a high load flow capacity, and at some neighboring utilities and generation interties. PMUs capture real time power system data and DFRs capture the sequence of events on power system disturbances for post event analysis. The DFR or PMU projects are typically the same. PMU is an added capability in the DFR or may be a separate device all together.

Transmission Owners must be compliant with NERC PRC 002-2 by July 1, 2022. NERC PRC-002-2[5] provides requirements and measurements for Transmission Owners with regards to identification, notification, and evaluation of any type of disturbance on their system. SCE meets the compliance requirements of PRC-002-2 through installation of DFRs and PMUs.

### b. Methodology

Replacement of an obsolete PMU is accomplished through a combination of infrastructure replacement work and bundled capital projects. SCE takes advantage of substation construction projects to upgrade PMUs when possible, as efficiencies can be realized by coupling the PMU installation with other capital work. PMU upgrades are prioritized based on obsolescence of hardware, while ensuring that SCE's PRC-002-2 sites are upgraded in time to meet the compliance deadline. SCE also prioritizes requests from its Grid Control Center (GCC) for upgrades to ensure GCC personnel have the necessary situational awareness.

[5] *Available at* https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-002-2&title=Disturbance%20Monitoring%20and%20Reporting%20Requirements&jurisdiction=United%20States.

### 3. Other Compliance Program That Did Not Meet the Threshold for Inclusion in This TMCR Report

#### a. Transmission Deteriorated Pole Replacement

##### 1) Program Description and Criteria

There are approximately 100,000 thousand transmission wood poles in SCE's system. Wood poles are inspected routinely through intrusive inspections and detailed visual inspections. SCE is maintaining the number of grid-based transmission intrusive inspections at approximately 10,000 wood transmission poles per year through 2023. Poles that do not pass inspection are marked for replacement on a priority basis.

"Intrusive" inspections involve drilling into the pole's interior in order to measure the extent of any internal decay, which is typically undetectable with external observation only. Detailed inspections involve visual examination of the pole's exterior condition as well as the condition of components on the pole. Detailed inspections are performed on a ten-year cycle. Like intrusive inspections, detailed inspections can result in the creation of work orders, which result in requests for pole replacements.

Poles will be identified for replacement from a variety of other sources. These "Other Program" poles can include those identified by Senior Patrolmen as part of transmission grid maintenance and identified as being unsuitable for climbing or insufficiently strong to support new equipment, or poles initially identified for repair but later concluded to be too deteriorated.

### 2) Methodology

Wood pole replacements or repairs are prioritized based on remaining shell strength and pole load calculations based upon location, remaining shelf strength and pole load calculations.

SCE Remedial Action Codes /Priorities for wood poles:

- RAC 1: Replace Pole – Priority 1 (72 hours)
- RAC 2: Replace Pole – Priority 2A (1 year)
- RAC 3: Replace Pole – Priority 2B (2 years)
- RAC 4: Replace Pole – Priority 2C (3 years)
- RAC 5: Steel Stub – Priority 2C (3 years)

## B. Infrastructure Replacement and Capital Maintenance

Infrastructure Replacement (IR) is defined as the programmatic replacement of assets that are nearing the end of the asset lifecycle, assets that are becoming obsolete in the industry, or assets that are problematic to the resiliency of the system. Capital Maintenance includes maintenance spending on existing facilities that is capitalized. For example, certain repairs to corroded towers and certain overhead conductor replacement is considered Capital Maintenance. The replacement could be "in kind" or could involve installation of equipment that has additional standard features. Examples include, but are not limited to, substation transformers, circuit breakers, transmission poles and other structures, and replacement of deteriorated conductors and insulators.

***Table V-2***
***INFRASTRUCTURE REPLACEMENT AND CAPITAL MAINTENANCE***

| | 2022 FORECAST ($ THOUSAND) | 2023 FORECAST ($ THOUSAND) | 2024 FORECAST ($ THOUSAND) | TOTAL ($ THOUSAND) |
|---|---|---|---|---|
| TOTAL | **$90,624** | **$86,808** | **$70,398** | **$247,831** |
| **SUBSTATION** | $49,122 | $52,491 | $36,081 | $137,694 |
| **TRANSMISSION** | $41,502 | $34,317 | $34,317 | $110,137 |

### 1. Substation Infrastructure Replacement

Substation-IR (Sub-IR) reduces the impact of aging infrastructure on the reliability and safety of SCE's grid by replacing substation equipment and structures before they cause an unplanned outage that risks public and employee safety. The program looks to optimize Operations and Maintenance (O&M) and capital expenditures, continuously understand risks and consequences of equipment failures, and better determine end of life on equipment.

The following programs are within scope for this TMCR report: Bulk Power 500kV and 220kV Line Relay Replacement, Non-Bulk Relay Replacement, Substation Transformer Bank Replacement, Substation Switchrack Rebuild, Substation Miscellaneous Equipment Additions and Betterment, Critical Spare Transformer Equipment Program, and Bulk Power Circuit Breaker Replacement. The FERC Emergency Equipment Program (EEP) does not have capital costs that meet the threshold for inclusion, but it is discussed below as an example of a program that may be in future reports.

***Table V-3***
***SUBSTATION INFRASTRUCTURE REPLACEMENT***

| | 2022 Forecast ($ Thousand) | 2023 Forecast ($ Thousand) | 2024 Forecast ($ Thousand) | Total ($ Thousand) |
|---|---|---|---|---|
| **Total** | **$49,122** | **$52,491** | **$36,081** | **$137,694** |
| **Bulk Power Relay** | $8,319 | $8,000 | $8,000 | $24,319 |
| **Non-Bulk Relay** | $1,158 | $1,192 | $1,000 | $3,350 |

| | | | | |
|---|---|---|---|---|
| **Transformer Bank Replacement** | $4,675 | $5,410 | 0 | $10,085 |
| **Switchrack Rebuild** | $5,500 | $4,510 | $5,237 | $15,247 |
| **Misc. Equip. Additions & Betterment** | $13,711 | $12,862 | $12,500 | $39,073 |
| **Critical Spare Transf. Equip. Program** | $8,869 | $16,418 | $9,344 | $34,630 |
| **Bulk Power Circuit Breakers** | $6,890 | $4,099 | 0 | $10,989 |

### a. Relay Replacement Programs

#### 1) Program Description and Criteria

The Bulk Power 500kV & 220kV Line Relay Replacement Program and Non-Bulk Relay Replacement Program (SRRP) identify and proactively replace substation protective relays, automation and control equipment. These programs are driven by equipment obsolescence and compliance requirements (where applicable).

#### 2) Methodology

The prioritization of relay replacements is based on a number of factors: age of the relay; relay obsolescence; level of effort required to maintain a complex and unique relay model; system criticality; and current protection and compliance requirements. These are discussed further below:

Age of the relay: Relays that have reached their end of life, or that have become obsolete and no longer serviceable, are targeted for replacement. Relays testing out of tolerance during routine testing that cannot be repaired are also targeted by the program. Another aspect of older relays is that they may not be recording events. The replacement of these relays helps with data recording when an event occurs.

Relay obsolescence: Another driver is the need to have more functionality in a relay such as added protection capabilities, event recording and alarming for failure. SCE may want to replace an electromechanical relay with a digital relay for added functions that are included with a digital relay.

Level of required effort: There are some relays that require excessive resources to maintain. It may not be cost effective to keep maintaining such relays due to the complexity and uniqueness of the relay and a need for unique, specified knowledge to maintain them.

System criticality: The criticality of the system that the relay protects is taken into consideration. For example, SCE considers the impacts should a relay fail or have a mis-operation. In many cases, SCE will proactively replace an older relay in favor of reacting to an imminent failure.

Current protection and compliance requirements: The current relay may not be capable of new compliance requirements or protection needs such as relay coordination parameters.

### b. Substation Transformer Bank Replacement Program (AA Bank & A-Bank)

#### 1) Program Description and Criteria

Substation transformers are major pieces of equipment used to either (1) increase electricity voltage to reduce energy losses during its transmission over long distances, or (2) reduce electricity voltage to make it more practical for use for consumers. A transformer will be identified as needing replacement based on age and probability of failure.

There is one substation transformer replacement project that met the threshold for this TMCR report:

| Substation | Voltage (High) | Voltage (Low) | Operating Date |
|---|---|---|---|
| **Vincent** | 500 | 220 | 2023 |

## 2) Methodology

SCE identifies and replaces transformers approaching the end of their service lives. Transformer replacements are identified primarily through Weibull analysis and an asset Health Index.  The Weibull analysis identifies the volume of transformer replacements needed per year based on age and probability of failure.  After deriving the number of transformers to be replaced each year, SCE identifies those transformers whose replacement is most urgent by using the Health Index.

In substation infrastructure replacement, the Health Index aides in prioritizing the replacement for the transformer population with the highest risk and consequence failure. A Health Index is a quantifiable characteristic of a population in which there is supporting evidence for describing the health of a population. Typically, the research methodology is to gather information, use subject matter expert opinion and input, use statistics in an attempt to generalize the information collected to the entire population, then use the statistical analysis to make a statement about the health of the population. Assets are assigned a “Health Index,” which is an asset score designed, in some way, to reflect or characterize asset condition and asset performance in terms of the asset's role. This table below is an example of the types of Health Index scores assigned to assets.

| Health Index Population Chart | |
|---|---|
| **Condition Category** | **Health Index Range** |
| Very Good | 86-100 |
| Good | 71-85 |
| Fair | 51-70 |
| Poor | 31-50 |
| Very Poor | 0-30 |

To derive a transformer's health index, SCE utilizes a multiplicative formulation that incorporates information such as inspections data, Predictive Maintenance Assessment (PMA), Transformer Oil Analysis (TOA), Oil Tap Changer Analysis (OTA), Dissolved Gas Analysis (DGA), notification, equipment test data, and field condition assessment.

### c. Substation Switchrack Rebuild Program

#### 1) Program Description and Criteria

The Substation Switchrack Rebuild program involves the demolition of existing switchracks and the construction of new substation or substation switchrack structures. Rebuilds are triggered for at least one of the following three reasons:

- Switchracks are often very old and/or determined to fall outside of current compliance requirements (i.e. seismic), may have deteriorated lattice steel, pipe-steel, wood-pole, or cubicle switchgear components;
- Physical congestion/clearance issues in existing switchrack areas may create unsafe operating conditions; or

- The existing switchrack structure may be unable to support or safely accommodate new equipment installations.

Switchrack replacements are also considered when installing new driveways, moving existing fences, or adding a new Mechanical Electrical Equipment Room (MEER) to house substation relays and battery systems. SCE continuously evaluates alternatives in lieu of rebuilding.

##### 2) Methodology

SCE relies on relevant information gathered during a scoping job walk, where additional or required scope can be identified. This work is then bundled whenever possible with existing capital projects to reduce additional outages, for efficient use of resources, and to decrease costs of the overall program.

#### d. Substation Miscellaneous Equipment Additions & Betterment Program

##### 1) Program Description and Criteria

The Substation Miscellaneous Equipment Additions & Betterment program includes planned capital maintenance that is typically driven by substation inspection and maintenance programs. Activity within this program is driven by the imminent failure of equipment or possible safety issues.

##### 2) Methodology

All equipment classes, including the major equipment categories (circuit breakers, transformers and relays) can be replaced for reactive reasons in this category. These replacements are predominantly like-for-like replacement with limited engineering required.

Equipment that is identified as requiring replacement must be replaced in a timely manner because substation equipment failures may lead to prolonged outages, unsafe operating conditions, or more expensive reactive solutions. This typically includes trench covers, potential transformers, current transformers, batteries, charges, as well as emergent circuit breakers, B-banks and disconnect replacements that are not covered under a specific commodity capital program.

#### e. Critical Spare Transformer Equipment Program

##### 1) Program Description and Criteria

The Spare Transformer Equipment Program (STEP), which is maintained within the EEP, is a voluntary transformer sharing program put together to help mitigate the impact of a terrorist event that targets key substation equipment. The program focuses on large transformers, as the lead times are well over a year. Any investor-owned, government-owned, or rural electric cooperative electric company in the United States or Canada may participate in the program.

##### 2) Methodology

The sharing agreement is triggered by an act of sabotage on a utility substation. The impacted utility must use up its own available resources to mitigate the damage prior to calling on the sharing agreement. Thus, work within this program is reactive and prioritized according to criticality.

#### f. Bulk Power Circuit Breaker Replacement Program

##### 1) Program Description

Circuit breakers are major pieces of equipment used to interrupt the flow of electricity through a circuit. Circuit breakers are essential in preventing equipment damage and public injury when faults occur in their downstream circuits. The following table illustrates which circuit breakers met the threshold for inclusion in this TMCR Report:

| Substation | Voltage Class | Operating Date | Quantity of Circuit Breakers |
|---|---|---|---|
| **Vincent** | 500 | 2023 | 3 |
| **Mira Loma** | 500 | 2023 | 2 |
| **Devers** | 500 | 2022 | 2 |

### 2) Criteria and Methodology

The Bulk Power Circuit Breaker Replacement program identifies and replaces bulk power circuit breakers approaching the end of their service lives that contain parts known to be problematic, no longer available, or that can no longer be cost-effectively maintained. Circuit Breaker replacements are identified similarly to transformers using Weibull analysis and the Health Index. As previously discussed with regards to substation transformers, the Health Index aides in prioritizing and replacing the correct asset population with the highest risk and consequence of failure.

To derive the circuit breakers' health index, SCE utilizes a multiplicative formulation that incorporates information such as inspection data, overstress percentage, Predictive Maintenance Assessment (PMA), circuit breaker analysis (CBA), Oil Circuit Breaker Analysis (OCBA), notification, and field condition that determines the degradation and deterioration of a circuit breaker.

### g. Other Substation Infrastructure Replacement Program That Did Not Meet the Threshold for Inclusion in This TMCR Report.

#### 1) Emergency Equipment Program

The Emergency Equipment Program (EEP) maintains an inventory of major substation equipment such as power transformers, circuit breakers, and disconnect switches not readily available in the marketplace for procurement and delivery. In order to avoid or mitigate potential reductions in reliability, SCE maintains a reserve inventory of such equipment. Inventory levels are prioritized based on in-serviced equipment counts to ensure grid reliability.

## 2. Transmission Capital Maintenance

The programmatic replacement of transmission assets that are nearing the end of the asset lifecycle or special projects are placed into the Infrastructure Replacement program. SCE has three transmission capital maintenance programs that met the threshold for inclusion in this 2020 TMCR Report: Tower Corrosion, Transmission Grid-Based Maintenance, and Infrastructure Replacement Overheard Conductor. Additionally, SCE includes a brief discussion of the switch replacement program, underground cable replacement program, overhead conductor replacement program, and the line relocation program as other programs that do not currently meet the threshold for inclusion in this TMCR.

***Table V-4***
***TRANSMISSION CAPITAL MAINTENANCE***

| | **2022 Forecast ($ Thousand)** | **2023 Forecast ($ Thousand)** | **2024 Forecast ($ Thousand)** | **Total ($ Thousand)** |
|---|---|---|---|---|
| **Total** | $41,502 | $34,317 | $34,317 | $110,137 |

| | | | | |
|---|---|---|---|---|
| **Tower Corrosion** | $20,991 | $21,008 | $21,008 | $63,006 |
| **Transmission Grid-Based Maintenance** | $13,011 | $13,310 | 13,310 | $47,131 |
| **Transmission IR Overhead Conductor** | $7,500 | | | |

a. Tower Corrosion

1) Program Description and Criteria

By 2020, more than 90% of SCE's transmission towers will be at least thirty years old. Thirty years is the average age at which the first signs of tower corrosion, from minor to severe, generally are revealed. If not identified and addressed, steel loss due to corrosion could lead to structure failure. Based on the severity of corrosion and the location, SCE can perform the following remedies: footing repair, footing replacement/rebuild, sandblasting, tower coating application, corroded steel lattice member replacement, or structure replacement.

2) Methodology

SCE's forecast for this activity is based on unit costs and scope estimates from SCE engineering efforts and an internal pilot program, both for assessments and for remediation. Assessment and testing practices will take place on all of SCE's towers to identify further remediation needs. Assessment costs are for bore scope, ultrasonic, and engineering assessments. Bore scope and engineering assessments are performed on transmission towers, while ultrasonic testing is used for tubular steel poles (TSPs). For remediations, SCE has known project scope and anticipated scope that will arise from forthcoming assessments and testing.

SCE will also target high risk structures within SCE's HFRA in an effort to assess and remediate transmission towers that pose the highest wildfire risk. To do this, SCE will leverage the various wildfire risk analysis tools SCE has developed in support of its broader wildfire mitigation efforts. Additional information on these tools and models can be found in SCE's 2020 Wildfire Mitigation Plan.

### b. Transmission Grid-Based Maintenance

#### 1) Program Description and Criteria

SCE has a robust transmission inspection and maintenance program wherein circuits and equipment are inspected on a programmatic basis. Pursuant to CPUC requirements for inspection and maintenance programs, SCE inspects right of ways, conductors, structures and hardware components for "break/fix" items. Based on these inspections, capital replacements are then identified. Capital replacements may include pole replacement, tower replacement, switch replacement, overhead and underground conduct replacement, underground structures/conduit replacement, and pothead/arrestor replacement. In regards to pothead replacement, older style potheads show a propensity to fail after 20-25 years of use. As a best practice, the older style potheads (nearing 20 years) are systematically replaced. The replacements are scheduled based on order of importance and risk level.

#### 2) Methodology

Within this program, SCE workers review the identified equipment issue and classify the resulting work based on a prioritization scale: P1, P2 and P3. The first level of prioritization (P1) requires immediate remediation within 72 hours. The second level (P2) has two classifications: (1) Tier 3: remediation within six months and (2) Tier 2:

remediation in 12 months. Additionally, within non-high fire risk areas with a (P2) classification, there can be a 12-month to three-year time frame depending on observations made by field personnel. The third level of prioritization (P3) requires remediation five years from the date the issue is identified.

### c. Overhead Conductor Replacement Program

Overhead conductor analytics and poor performing circuits are used to identify interruptions and prioritize overhead conductors to be replaced. Generally, as a matter of practice, smaller, more brittle conductors are targeted for replacement.

### d. Other Transmission Capital Maintenance Programs That Did Not Meet the Threshold for Inclusion in This TMCR Report.

#### 1) Switch Replacement Program

This program involves the replacement of switches that are obsolete and no longer manufactured.  On an annual basis, switches are identified for replacement and added to the Transmission-IR program. Replacements are scheduled based on order of importance and risk level.

#### 2) Underground Cable Replacement Program

Through cable analytics, poor performing underground cables are identified to be replaced.  The Outage Database and Reliability Metrics (ODRM) tracking system is used to log interruptions and prioritize poor performing cables to be replaced. These analytics, along with feedback from certified and trained field personnel, determine priority and need of replacement.

#### 3) Line Relocation Program

Work within this program is prioritized based on safety, reliability, and the need to relocate lines. These line relocations could be due to flooding, wash outs, property disputes, access issues, etc. Line relocations are identified by trained field personnel who evaluate potential hazards under certain conditions.

### C. Wildfire Management

SCE has significantly expanded its efforts to reduce wildfire risks. SCE's 2020 Wildfire Mitigation Plan (WMP), which was filed with the CPUC on February 7, 2020, sets forth a comprehensive plan to harden infrastructure, manage vegetation, perform detailed inspections, remediate issues, and enhance our situational awareness. In its 2020 WMP, SCE has detailed numerous mitigation strategies to remediate wildfire risks associated with SCE's transmission system. Accordingly, SCE refers stakeholders to SCE's 2020 WMP and its associated record for detailed information on the various wildfire mitigation programs not addressed in this TMCR.

***Table V-5***
***WILDFIRE MANAGEMENT***

| | **2022 Forecast ($ Thousand)** | **2023 Forecast ($ Thousand)** | **2024 Forecast ($ Thousand)** | **Total ($ Thousand)** |
|---|---|---|---|---|
| **High Fire Risk Informed Inspection Program** | $1,961 | $2,255 | $1,889 | $6,104 |

### 1. High Fire Risk Informed Inspection & Remediation Program

#### a. Program Description and Criteria

CPUC GO 95 Rule 18 has designated adjusted compliance timeframes for issues identified in HFRA. With this framework in mind, SCE has conducted inspections of all overhead transmission structures and equipment in HFRA with a focus on potential ignition risk conditions. The initial phase of these Enhanced Overhead Inspections (EOI) started in late 2018 and was completed in 2019. In 2020, SCE is incorporating lessons learned and best practices from EOI into a broader redesign of our inspection practices, which will be performed as part of the emergent High Fire Risk Informed Inspection Program (HFRI). The main driver of this initiative is to transition from a compliance-focused inspection approach to a risk-informed approach.

#### b. Methodology

SCE is identifying and remediating risks on our transmission system by performing ground and aerial inspections within SCE's HFRA and performing mitigation work as required. These mitigations include but are not limited to conductor replacement, shield wire repair/replacement, structure/footing replacement, structure refurbishment and/or retrofit, and smaller item replacement such as insulators, splices, spacers and jumper loops. While the costs to perform the ground and aerial inspections are expensed, much of the associated remediations are capitalized and are captured within this program.

The HFRI program will use advanced wildfire risk modeling to estimate the amount of risk expected at particular locations that require remediation. This risk modeling evaluates the probability of failure and likelihood of ignition, fire propagation potential, and the associated impacts. A single consequence variable is developed to help prioritize what areas need to be inspected first. Additional details on the HFRI Program, and its prioritization model, are available in SCE's 2020 WMP.

Once the ground and aerial inspections have identified issues that need to be mitigated, SCE uses a structured approach to classify and prioritize the remediations. The first level of prioritization (P1) requires immediate remediation within 72 hours. The second level (P2) has two classifications: (1) Tier 3: remediation within six months and (2) Tier 2: remediation in 12 months. The third level of prioritization (P3) requires remediation five years from the date the issue is identified.

## D. Work Performed by Operating Agent

This category includes, but is not limited to, line relocations, new service interconnections, and city-sponsored infrastructure project-related transmission system modifications.

***Table V-6***
***WORK PERFORMED BY OPERATING AGENT***

| | 2022 Forecast ($ Thousand) | 2023 Forecast ($ Thousand) | 2024 Forecast ($ Thousand) | Total ($ Thousand) |
|---|---|---|---|---|
| **LADWP** | $2,321 | $1,232 | $1,267 | $4,820 |

### 1. Los Angeles Department of Water and Power (LADWP)

#### a. Program Description and Criteria

Under this category, work activities are coordinated with Los Angeles Department of Water and Power (LADWP), which is the operator of the Pacific Direct Current Intertie (PDCI). The activities include the replacement of approximately 80,000 old porcelain suspension insulators with new glass insulators. The project driver is the existing porcelain insulators are not compliant with current industry standards.

As a 50% joint owner of the PDCI, SCE is contractually obligated to cooperate with LADWP in any capital replacements, additions, and betterments related to the PDCI. LADWP submits its proposed capital project and obtains SCE approval. SCE is responsible to pay for its 50% share of the LADWP's capital costs.

#### b. Methodology

Prioritization and planning of work belong to LADWP. As operator of the PDCI transmission line, LADWP is contractually responsible for the operations, maintenance, coordination, and execution of work.

### E. Operations Support

This category includes projects that support transmission operations by improving and securing operation facilities that enhance efficiency and flexibility to manage transmission system work. Facility maintenance examples also include seismic mitigation of control buildings, grounds, fencing, etc.

***Table V-7***
***OPERATIONS SUPPORT***

| | 2022 Forecast ($ Thousand) | 2023 Forecast ($ Thousand) | 2024 Forecast ($ Thousand) | Total ($ Thousand) |
|---|---|---|---|---|
| Total | **$14,322** | **$14,440** | **$22,561** | **$51,324** |
| **SUBSTATION CAPITAL MAINTENANCE FACILITIES** | $5,902 | $6,020 | $6,161 | $18,084 |
| **SEISMIC MITIGATION (LINES & SUBS)** | $8,420 | $8,420 | $16,400 | $33,240 |

### 1. Substation Capital Maintenance (ISO Facilities)

#### a. Program Description and Criteria

SCE's Substation Capital Maintenance Program seeks to preserve the value of SCE's buildings, equipment, and grounds, making them as safe, reliable, and productive as reasonably possible. Corrective facility work orders are entered to respond to emergent issues. Proper asset management requires a proactive capital maintenance program to repair or replace building systems and components that are damaged, degraded, non-operational, non-compliant, or have reached their end of useful life. This Program is addressed in ten categories: (1) Electrical/Fire systems, (2) Fencing and Walls, (3) Flooring, (4) HVAC, (5) Paving, (6) Roof Repairs, (7) Lighting, (8) Restroom Remodels, (9) Specialty Equipment and (10) Other Repairs.

For this program, SCE will:

- Replace or upgrade the electrical, lighting, mechanical, and plumbing systems.
- Replace or upgrade other building infrastructure, systems, and sub-systems, such as asphalt, roofing, fire detection/prevention and perimeter fencing.
- Replace or remediate degraded interior building components such as doors, ceilings, flooring and workplace improvements.

#### b. Methodology

SCE has developed an asset management methodology to prioritize facility and capital work. SCE evaluates four factors: (a) the condition of a facility (Facility Condition Index); (b) the need for a facility to deliver utility services to SCE customers (Asset Priority Index); (c) the functionality and utility of a facility for business use(s) (Fitness for Purpose); and (d) the requirement to account for federal and state laws, regulations impacting facility use, maintenance, design, construction practices, and building codes (Compliance).

SCE contracts with a third-party independent vendor to perform building condition assessments for a subset of our substations each year. These assessments will be performed annually until all substations have been reviewed and a facility condition report has been completed. After the yearly assessment is completed, any deficiencies identified are prioritized and items are addressed in accordance with the criticality of the deficiency. Lastly, SCE considers the availability of funding for such corrections.

### 2. Seismic Mitigation for Transmission Assets (Lines and Substations)

#### a. Program Description and Criteria

The Seismic Program, consolidated under Business Resiliency, is part of a larger, mostly CPUC funded effort beyond just the FERC dollar request. The broader seismic program centralizes and coordinates across organizational units to assess and perform mitigations as identified to increase safety, infrastructure reliability and maintain regulatory requirements. The primary objectives of the Seismic Assessment and Mitigation Program are to: (1) assess SCE's electric infrastructure (transmission lines and substations), non-electric facilities, generation, and telecom infrastructure and identify what seismic mitigations are needed, and (2) mitigate risks by making the necessary retrofits and improvements in order to increase reliability and reduce the risk of harm to workers, customers and communities due to a moderate or major earthquake.

Within this TMCR, SCE addresses the seismic mitigation activities pertaining to SCE's transmission system assets, which include both transmission line infrastructure and substation assets. Examples of mitigations for these assets include bracing and anchoring electrical equipment in substations, improving conductor slack, structural work to reinforce building wall to roof connections, and replacing aged equipment with modern equipment designed to withstand greater levels of seismic activity. Other work includes more detailed assessments of significant transmission tower corridors along the earthquake faults to determine possible landslide risk and mitigate said risk accordingly to ensure reliability.

SCE conducts hazard and vulnerability assessments on its infrastructure in order to (1) understand the seismic exposure and impacts of seismic events, (2) assess the functionality and stability of the infrastructure if a seismic event occurred, and (3) identify applicable design standards and codes. Assessments utilize a combination of site surveys, seismic modeling, and geographic information systems.

SCE expects to complete six MEER/Transmission Substation projects in 2022, five in 2023, and another five to six MEER projects in 2024. Costs per project range from one million to six million per unit depending on size.

### b. Methodology

Seismic mitigations are prioritized with a focus on keeping people safe and minimizing interruptions in electric service. Projects with the highest safety, reliability, and compliance impact will be executed first. This includes populated buildings and transmission, distribution, generation, and telecom infrastructure critical to maintaining business continuity and operational reliability. As mentioned in the criteria above, reviewing the data against the United States Geological Survey's probabilistic scenarios informs the prioritization of transmission infrastructure in terms of imminent failure should moderate to high seismic activity occur. In addition to the prioritization method used, some projects may be escalated in order to bundle work for efficiency purposes and to minimize outages. Projects related to high-hazards dams with pending FERC reviews will be prioritized accordingly.

## F. Physical/Cyber Security

While SCE's TOT does not require the inclusion of physical and cyber security activities within the TMCR, SCE is providing some information describing the nature of our physical security efforts that protect critical infrastructure. This category consists of SCE's Grid Infrastructure Protection Tier Program, which is a program dedicated to the physical protection of SCE employees, the general public, and SCE assets at electric facilities. This program protects SCE's grid infrastructure assets against physical attacks, theft, vandalism, security breaches, and more.

***Table V-8***
***PHYSICAL SECURITY***

| | 2022 FORECAST ($ THOUSAND) | 2023 FORECAST ($ THOUSAND) | 2024 FORECAST ($ THOUSAND) | TOTAL ($ THOUSAND) |
|---|---|---|---|---|
| **PHYSICAL SECURITY** | $26,400 | $29,550 | $20,617 | **$76,566** |

### a. Program Description and Criteria

The Tier Program involves the installation of security measures at the most critical facilities (~~e.g~~. vital substations and heavily populated areas) based on the level of criticality and potential impact of a security breach. The criticality label is based on operation need, evolving threats, and physical security risks to the bulk electric system. The installations will improve protection of critical assets, buildings and people around electric facilities.

SCE has criteria for compliance and non-compliance related physical security measures. For compliance criteria, such as NERC CIP 014, SCE adheres to the requirements allotted. For non-compliance security programs and projects, SCE assesses the level of criticality and potential impact of a security breach to the electric system.

### b. Methodology

Compliance related projects are projects that SCE must adhere to and prioritize based on the deadlines of the requirements. For the NERC programs, SCE prioritizes facilities that must go through third-party review and NERC approval. Non-compliance projects are prioritized based on criticality to business operations, risk level of the facility, and level of work required.

# VI. Appendices

## Appendix A - Stakeholder Meeting and Related Activities

During each TMCR cycle, SCE will conduct a stakeholder meeting to review the TMCR with interested parties and the parties will have an opportunity to pose questions, offer suggestions, or raise concerns directly with SCE. Stakeholders then have an opportunity to provide written comments to SCE. No later than 10 days after the comment deadline, SCE will post all timely received comments. After reviewing and considering comments, SCE will release a final TMCR. As appropriate, SCE may modify the final TMCR to include revisions in light of stakeholder comments.

***Table VI-1***
***Schedule for the 2020 TMCR***

| DUE DATE | ACTIVITY |
|---|---|
| May 15, 2020 | SCE posts meeting notice and draft TMCR report |
| June 26, 2020 | SCE conducts public stakeholder meeting and posts comments template |
| July 27, 2020 | Stakeholders submit comments on draft TMCR report |
| August 10, 2020 | SCE posts stakeholder comments on draft TMCR report |
| September 29, 2020 | SCE posts final TMCR report |

| | |
|---|---|
| October 13, 2020 | Stakeholders submit comments on final TMCR report |
| October 27, 2020 | SCE posts stakeholder comments on final TMCR report |

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## Appendix B - Underlying Financial Data for Major Program Categories

### Table VI-2
### Appendix B – 2020 TMCR Forecast

| PIN | Project Title | OD | WBS | 2022 | 2023 | 2024 | Total | Unit Count (if available) |
|---|---|---|---|---|---|---|---|---|
| | **Infrastructure Replacement and Capital Maintenance** | | | | | | | |
| | Replace Bulk Power Circuit Breakers -Vincent | 2023 | CET-ET-IR-CB-421100 | 4,168,115 | 3,279,435 | - | 7,447,550 | 5 |
| | Replace Bulk Power Circuit Breakers - Devers | 2022 | CET-ET-IR-CB-421100 | 809,569 | - | - | 809,569 | 2 |
| | Replace Bulk Power Circuit Breakers - Mira Loma | 2023 | CET-ET-IR-CB-421100 | 1,912,327 | 819,569 | - | 2,731,896 | 2 |
| **4211** | **Bulk Power Circuit Breakers/Switches Replacement Program** | 2022-2023 | | **6,890,011** | **4,099,004** | **-** | **10,989,015** | 9 |
| | Substation Transformer Bank Replacement (AA-Bank & A-Bank) - Vincent | 2023 | CET-ET-IR-TB-521001 | 4,674,577 | 5,410,201 | - | 10,084,778 | 1 |
| **5210** | **Substation Transformer Bank Replacement Program (AA-Bank & A-Bank)** | | | **4,674,577** | **5,410,201** | **-** | **10,084,778** | 1 |
| **3362** | Critical Spare Equipment Program | 2022-2024 | CET-PD-CI-CI-CRINSSP | 8,869,003 | 16,417,624 | 9,343,855 | 34,630,481 | |
| **5089** | Bulk Power 500kV & 220kV Line Relay Replacement | 2022-2024 | CET-ET-IR-RP-508900 | 8,319,042 | 8,000,000 | 8,000,000 | 24,319,042 | |
| **4343** | Non-Bulk Relay Replacement Program ("SRRP") | 2022-2024 | CET-ET-IR-RP-434301 | 1,158,168 | 1,192,262 | 1,000,000 | 3,350,430 | |
| **4756** | Substation Miscellaneous Equipment Additions & Betterment | 2022-2024 | CET-ET-IR-ME-475600 | 13,361,618 | 11,886,864 | 12,500,000 | 37,748,482 | |
| **7716** | Substation Batteries and Chargers | 2022-2024 | CET-ET-IR-ME-771601 | 349,408 | 974,916 | - | 1,324,324 | |
| | **Substation Miscellaneous Equipment Replacement** | 2022-2024 | | **13,711,026** | **12,861,780** | **12,500,000** | **39,072,806** | |
| **7713** | Substation Switchrack Rebuild | 2022-2024 | CET-ET-IR-RB-771301 | 5,500,000 | 4,510,000 | 5,237,343 | 15,247,343 | 1 |
| **3364** | Transmission Grid-Based Maintenance | 2022-2024 | CET-PD-IR-TG-TRSJAC | 13,011,561 | 13,309,593 | 13,309,593 | 39,630,747 | |
| | Chevmain-El Nido 220 kV lines Reconductoring | 2022 | CET-PD-IR-TP-789000 | 2,500,000 | - | - | 2,500,000 | |
| | Chevmain-El Segundo 220 kV lines Reconductoring | 2022 | CET-PD-IR-TP-789000 | 2,500,000 | - | - | 2,500,000 | |
| | El Nido-El Segundo 220 kV lines Reconductoring | 2022 | CET-PD-IR-TP-789000 | 2,500,000 | - | - | 2,500,000 | |
| **3364** | **Transmission IR Overhead Conductor** | | | **7,500,000** | **-** | **-** | **7,500,000** | |
| **3364** | Transmission Tower Corrosion Program | 2022-2024 | CET-PD-IR-TS-TRSJAC | 20,990,509 | 21,007,700 | 21,007,700 | 63,005,909 | |
| | **Total IR and Capital Maintenance** | | | **90,623,897** | **86,808,164** | **70,398,491** | **247,830,551** | **11** |
| | **Compliance** | | | | | | | |
| | EAGLE MOUNTAIN - BLYTHE | 2023 | CET-PD-OT-PJ-729801 | 8,660,625 | 2,511,565 | - | 11,172,190 | |
| | BIG CREEK No 1 - RECTOR | 2022 | CET-PD-OT-PJ-729801 | 1,725,000 | - | - | 1,725,000 | |
| | Pardee-Pastoria (North Coast) | 2022 | CET-PD-OT-PJ-729801 | 166,500 | - | - | 166,500 | |
| | BIG CREEK No 3 - RECTOR 2 | 2022 | CET-PD-OT-PJ-729801 | 5,886,500 | 11,800 | - | 5,898,300 | |
| | BIG CREEK No 2 - BIG CREEK No 3 | 2025 | CET-PD-OT-PJ-729801 | 11,500 | 11,500 | 218,000 | 241,000 | |
| | BIG CREEK No 3 - BIG CREEK No 8 | 2024 | CET-PD-OT-PJ-729801 | 11,500 | 172,000 | 9,694,811 | 9,878,311 | |
| | BIG CREEK No 2 - BIG CREEK No 8 | 2025 | CET-PD-OT-PJ-729801 | 11,500 | 11,500 | 798,716 | 821,716 | |
| | BAILEY - PARDEE | 2024 | CET-PD-OT-PJ-729801 | 17,561,442 | 9,900,000 | 3,300,000 | 30,761,442 | |
| | Pardee-Pastoria-Warne (North Coast) | 2022 | CET-PD-OT-PJ-729801 | 1,232,998 | - | - | 1,232,998 | |
| | Serrano-Valley (San Jacinto) | 2023 | CET-PD-OT-PJ-729801 | 200,000 | 3,455,960 | - | 3,655,960 | |
| | BIG CREEK No 3 - RECTOR 1 | 2024 | CET-PD-OT-PJ-729801 | 29,745,504 | 22,713,091 | 7,326,864 | 59,785,459 | |
| | LA FRESA - LAGUNA BELL | 2022 | CET-PD-OT-PJ-729801 | 200,000 | - | - | 200,000 | |
| | Lugo-Victor No.1 | 2023 | CET-PD-OT-PJ-729801 | - | 273,514 | - | 273,514 | |
| | PADUA - RANCHO VISTA No 1 | 2022 | CET-PD-OT-PJ-729801 | 207,000 | - | - | 207,000 | |
| **7298** | **Transmission Line Rating Remediation (Exempt from Licensing)** | | | **65,620,069** | **39,060,930** | **21,338,391** | **126,019,390** | 0 |
| 7867 | TLRR Eldorado-Pisgah-Lugo220 kV Transmission Project | 2026 | CET-PD-OT-PJ-7867* | 10,753,671 | 25,016,969 | 86,668,220 | 122,438,860 | |
| 7904 | TLRR Ivanpah-Control Project | 2026 | CET-PD-OT-PJ-7904* | 25,100,117 | 118,469,788 | 118,589,934 | 262,159,839 | |
| 7906 | TLRR Control-Silver Peak 55kV Project | 2026 | CET-PD-OT-PJ-7906* | 11,852,819 | 33,832,953 | 43,074,386 | 88,760,158 | |
| | **Transmission Line Rating Remediation (Licensing)** | | | **47,706,607** | **177,319,710** | **248,332,541** | **473,358,858** | 0 |
| | **Total Transmission Line Rating Remediation (TLRR)** | | | **113,326,676** | **216,380,640** | **269,670,932** | **599,378,248** | 0 |
| | Control 115/55 kV Substation | 2024 | CET-ET-GA-EM-644600 | - | 450,625 | 214,375 | 665,000 | |
| | Johanna 220/66 kV Substation | 2022 | CET-ET-GA-EM-644600 | 389,375 | - | - | 389,375 | |
| | Walnut 220/66 kV Substation | 2022 | CET-ET-GA-EM-644600 | 396,375 | - | - | 396,375 | |
| | Hinson 220/66 kV Substation | 2022 | CET-ET-GA-EM-644600 | 396,375 | - | - | 396,375 | |
| | Chevmain 220/66 kV Substation | 2021 | CET-ET-GA-EM-644600 | 389,375 | - | - | 389,375 | |
| | Pastoria 220/66 kV Substation | 2022 | CET-ET-GA-EM-644610 | 445,000 | - | - | 445,000 | |
| **6446** | **Phasor Measurement System Installations** | | | **2,016,500** | **450,625** | **214,375** | **2,681,500** | 0 |
| | **Total Compliance** | | | **115,343,176** | **216,831,265** | **269,885,307** | **602,059,748** | **0** |
| | **Wildfire Management** | | | | | | | |
| 8224 | Transmission Enhanced Overhead Inspections (EOI) Capital Remediations | 2022-2024 | CET-PD-WM-TP-822400 | 1,960,816 | 2,254,594 | 1,888,856 | 6,104,266 | |
| | **Total Wildfire Management** | | | **1,960,816** | **2,254,594** | **1,888,856** | **6,104,266** | 0 |
| | **Work by Operating Agent** | | | | | | | |
| 3138 | LADWP | 2022-2024 | CET-OT-OT-ME-313800 | 2,320,552 | 1,232,432 | 1,266,942 | 4,819,926 | |
| | **Total Work by Operating Agent** | | | **2,320,552** | **1,232,432** | **1,266,942** | **4,819,926** | **0** |
| | **Operations Support** | | | | | | | |
| 7637 | Substation Capital Maintenance (ISO Facilities) | 2022-2024 | COS-00-RE-MA-NE7637 | 5,902,345 | 6,020,392 | 6,161,443 | 18,084,180 | |
| | Seismic Program - Trans Subs (FERC) | 2022-2024 | COS-00-SP-TD-000000 | 5,120,000 | 5,120,000 | 6,400,000 | 16,640,000 | |
| | Seismic Mitigations for Transmission Line Assets | 2022-2024 | COS-00-SP-TD-000002 | 3,300,000 | 3,300,000 | 10,000,000 | 16,600,000 | |
| **7392** | **Seismic Mitigation Program** | 2022-2024 | | **8,420,000** | **8,420,000** | **16,400,000** | **33,240,000** | 0 |
| | **Total Operations Support** | | | **14,322,345** | **14,440,392** | **22,561,443** | **51,324,180** | **0** |
| | **Physical Security Enhancement Programs** | | | | | | | |
| | 500/220/115 kV Substation | 2020 | CET-ET-IR-ME-804200 | 920,791 | - | - | 920,791 | |
| | 500/220/66 kV Substation No.1 | 2020 | CET-ET-IR-ME-804201 | 4,613,319 | 997,787 | - | 5,611,106 | |
| | 500/220 kV Substation No.1 | 2020 | CET-ET-IR-ME-804202 | 3,732,980 | 819,103 | - | 4,552,083 | |
| | 500/220 kV Substation No.2 | 2020 | CET-ET-IR-ME-804203 | 3,895,414 | 853,651 | - | 4,749,065 | |
| | 500/220/66 kV Substation No.2 | 2021 | CET-ET-IR-ME-804204 | 3,477,004 | 761,355 | - | 4,238,359 | |
| | Tier 2 & Tier 3 Substations | 2022-2024 | CET-ET-IR-ME-804207 | 450,000 | 16,502,958 | 5,925,739 | 22,878,697 | |
| **8042** | **Physical Security Projects (Tiers 2 & 3)** | 2022-2024 | | **17,089,508** | **19,934,854** | **5,925,739** | **42,950,101** | 0 |
| 7454 | Physical Security Systems - Electric Facilities | 2022-2024 | COS-00-CS-CS-745400 | 9,310,081 | 9,615,127 | 14,691,008 | **33,616,215** | |
| | **Total Physical Security Enhancement Programs** | | | **26,399,589** | **29,549,981** | **20,616,747** | **76,566,316** | 0 |
| | **Total TMCR Forecast** | | | **250,970,376** | **351,116,827** | **386,617,785** | **1,065,271,304** | 11 |

## Appendix C – Response to Stakeholder Comments on Draft 2020 TMCR Report

On May 14, ,2020, SCE posted on its website its Draft 2020 TMCR Report. On June 26, 2020, SCE held a public meeting to review the Draft 2020 TMCR Report. On July 27, 2020, the California Public Utilities Commission (CPUC) provided comments on the Draft 2020 TMCR Report and the related stakeholder meeting. SCE appreciates comments submitted by stakeholders on the Draft 2020 TMCR Report. Below are responses to the CPUC's comments on various aspects of the Draft 2020 TMCR Report. Stakeholders have an opportunity to submit comments on SCE's Final 2020 TMCR Report within ten business days after it is posted.

SCE responds to parties' comments on the actual information contained in the Draft 2020 TMCR Report and presented during the June 26 stakeholder meeting as follows:

## I. General Stakeholder Comments on the Draft 2020 TMCR Report

SCE responds to parties' comments on the actual information contained in the Draft 2020 TMCR Report and presented during the June 26 stakeholder meeting as follows:

A. CPUC states, "The opportunity for discovery should be available to all stakeholders… Not accepting data requests from non-regulatory stakeholders leaves those stakeholders with limited information and few opportunities to appropriately analyze projects included in SCE's TMCR reports. An effective stakeholder process requires openness and transparency with all stakeholders, not just the ones that a utility must respond to by law."

B. SCE Response: Data requests are outside of the scope of the FERC approved TMCR tariff language. In order to promote transparency and engagement with all stakeholders, SCE hosted the Public Stakeholder Meeting after publishing the Draft TMCR Report. At this year's June 26 Public Stakeholder Meeting, multiple stakeholders in addition to the CPUC attended. No entity, including the CPUC, posed questions during the public meeting. Additionally, SCE invited all stakeholders to provide written comments on the Draft TMCR Report and Public Stakeholder Meeting by July 27. As of the noted deadline, only the CPUC provided comments to SCE. SCE has provided ample opportunity for non-regulatory stakeholders to engage throughout this process.

## II. Stakeholder Comments on the Scope of the TMCR Process

A. CPUC states, "The TMCR Report should include forecasts for years 1-2…As stated in the CPUC's comments on the 2019 TMCR Report, data for Years 1-2 is needed in addition to the data for Years 3-5 in order for stakeholders to understand how projects are being prioritized and implemented for the full five-year window. Excluding the most immediate two years' worth of data would effectively force stakeholders to research the information on their own and if the information is not available in other filings, perhaps formulate approximations based on less ideal data." P. 3

1. SCE Response: This request is outside the scope of the TMCR process. However, on June 24, 2020, the CPUC issued non-docketed data request question 3 to SCE which requested a list of projects with a need identified in Year 1 and 2 that were *not* included in the Draft TMCR Report. (See Question 3, CPUC's NDDR) In response to this question, SCE listed all known and identified projects related to the applicable TMCR categories.

B. CPUC states, "SCE's explanation of which projects and facilities are outside the scope of the TMCR in its Draft Report and the language in its TOT appear to be inconsistent with each other. SCE's TOT, Appendix XI, Section I states that 'projects or facilities outside the scope of the TMCR include facilities or projects that require an in-service date less than two years after their need being identified. According to the TOT language, projects whose needs were identified greater than two years before projected in-service dates falling in 2020 and 2021 (Years 1 and 2) would be within the scope of the TMCR process. However, the Draft Report simply states that "[p]rojects that are less than two years from their projected in-service date will not be included in the TMCR.'" P. 3

1. SCE Response: SCE believes the language in SCE's TOT, Appendix XI, Section I is consistent with that of the Draft TMCR Report. Those projects with in-service dates projected less than two years after their need is identified are not within the scope of the TMCR Report. Since this is the 2020 TMCR Report, year 1 is 2020 and year 2 is 2021. Thus, in applying SCE's TOT, those projects identified in 2020 as being needed, with an in-service date of 2020 or 2021, are *not* within scope for the 2020 TMCR Report.

C. CPUC states, "The projects in the TMCR forecasts should be presented on a more granular level…It is the CPUC's determination that a more transparent and helpful way to provide this data to stakeholders would be to provide it on a Work Order level in addition to providing the Integrated Work Plan (IWP) information associated with such projects."

1. SCE Response: The information provided in the TMCR report is consistent with the granularity allowed for the FERC approved TMCR tariff language. In addition, on June 24, 2020, the CPUC issued non-docketed data request, question 4(d), asking for the Integrated Work Plan information of each project listed in the TMCR Report. SCE provided this information in response.