

During the period January 2021 through December 2022, SCE forecasts:

- \$634 million in ISO non-incentive network transmission projected to go into rate base (including \$411 million in ISO Blanket-Specifics),
- \$306 million in FERC incentive rate qualified CWIP expenditures, and
- \$1,151 million of CWIP Expenditures projected to go into rate base.

In addition to the numerous but relatively small transmission projects, there are 31 significant transmission projects (each \$5 million or greater in ISO-related costs) that are projected to go into rate base during the forecast period January 2021 through December 2022 – 16 Blanket-Specifics (items 1 through 16 below), ten Specific non-incentive projects (items 17, 18, 21, and 24 through 30 below), and five Specific incentive projects (items 19, 20, 22, 23, and 31 below). These projects will increase the reliability of the ISO transmission grid, increase access to new generation resources to serve the ISO market, and/or provide congestion relief. SCE's Formula Protocols, Section 3(a) specifies that SCE will provide work papers detailing specific information regarding its capital forecast.

Table 1
Forecast Direct Capital Expenditures Projected to Go into Rate Base between 2021 and 2022
(Nominal \$Millions)

No.	PIN	Project	FERC CWIP	FERC Non-CWIP	Total
1	3138	Sylmar Convertor Station: Miscellaneous Capital Maintenance	-	11.929	11.929
2	3362	Critical Infra Spare - FERC Spare Transformer Equipment Program (STEP)/ Emergency Spares	-	13.343	13.343
3	3364	Transmission Tower Corrosion Program	-	42.798	42.798
4	3364	Transmission Grid-Based Maintenance	-	18.307	18.307
5	4211	Replace Bulk Power Circuit Breakers	-	9.770	9.770
6	4756	Substation Miscellaneous Equipment Additions & Betterment	-	26.971	26.971
7	5089	Bulk Power 500 kV & 230 kV Line Relay Replacement	-	14.508	14.508
8	6446	Phasor Measurement System Installations	-	7.578	7.578
9	7298	Transmission Line Rating Remediation	-	149.388	149.388

10	7392	Seismic Assessment and Mitigation Program for Transmission Assets	-	27.321	27.321
11	7573	Substation Fence/Gate (Cu Theft)	-	6.927	6.927
12	7949	Protection of Grid Infrastructure Assets	-	16.971	16.971
13	7637	Substation Facility Capital Maintenance	-	11.689	11.689
14	7713	Substation Switchrack Rebuilds	-	11.880	11.880
15	7890	Transmission Maintenance Planned - Overhead Conductor	-	9.750	9.750
16	8284	West of Colorado River CRAS Inland/Devers Extension	-	6.764	6.764
17	3138	LADWP AC/DC Filter Replacement	-	5.298	5.298
18	4057	September Wildfires CEMA Transmission Restoration and Erosion Control	-	8.691	8.691
19	5450	Riverside Transmission Reliability Project	47.774	-	47.774
20	6420	West of Devers Upgrade Project (WODUP)	653.453	4.840	658.293
21	7227	Casa Diablo IV Project Interconnection	-	12.610	12.610
22	7546	Eldorado-Lugo-Mohave (ELM) Upgrade	191.432	6.085	197.517
23	7555	Mesa Substation	242.932	1.177	244.109
24	7558	Magunden-Springville No.1 & 2 Tower Replacement ("Lake Success Towers in Water")	-	14.237	14.237
25	7763	Lugo-Victorville 500 kV T/L SPS	-	12.642	12.642
26	7820	Substation Physical Security Enhancements Project ¹	-	10.006	10.006
27	8042	Physical Security Enhancement Projects (Tiers 2 & 3)	-	14.555	14.555
28	8077	Annual Transmission Reliability Assessment 2016 - Protection Upgrades (ATRA)	-	20.223	20.223
29	8104	Moorpark-Pardee 230 kV No. 4 Circuit	-	52.811	52.811
30	8163	Red Bluff 2nd 500/230 kV AA Bank (Reliability Network Upgrades)	-	14.489	14.489
31	8169	Colorado River Substation Expansion – Installation of the 2 nd AA 1120 MVA 500/230 kV transformer bank	14.994	-	14.994
32	Various	Less than \$5m each	0.354	70.597	70.951
		Total	1,150.939	634.155	1,785.094

1. Sylmar Convertor Station: Miscellaneous Capital Maintenance (PIN: 3138)

The Sylmar Converter Station is the southern converter station of the Pacific DC Intertie (PDCI), an electric power transmission line which transmits electricity from the Celilo Converter Station outside The Dalles, Oregon to Sylmar in the northeastern San Fernando Valley region of Los Angeles, California. The

¹ PIN 7820 Substation Physical Security Enhancements Project is split between Blanket Specifics with \$0.666 million and Specific non-incentive with another \$9.340 million in ISO related capital additions to rate base (see WP Schedule 16 – Summary of ISO Cap Expenditures Non-Incentive Projects).

station converts the ± 500 kV high voltage direct current (HVDC) coming from the northern converter station Celilo to alternating current (AC) at 60 Hz and 230 kV synchronized with the Los Angeles power grid. The station capacity is 3,100 megawatts and it is jointly owned by Southern California Edison (SCE) and Los Angeles Department of Water and Power (LADWP).

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. The forecasted capital expenditures are for miscellaneous maintenance capital work activities, which include, but not limited to polymer insulators, removal of old electrodes, and bowed towers.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$11.929 million.

2. Critical Infrastructure Spares (PIN: 3362)

The Spare Transformer Equipment Program (STEP), which is maintained within the FERC Emergency Equipment Program (EEP), is a voluntary transformer sharing program put together to help mitigate the impact of a terrorist event that targets key substation equipment. The 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. 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. The STEP 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.

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.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$13.343 million.

3. Transmission Tower Corrosion Program (PIN: 3364)

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 show up. 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.

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 High Fire Risk Areas (HFRA) 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 (WMP).

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$42.798 million.

4. Transmission Grid-Based Maintenance (PIN: 3364)

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.

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.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$18.307 million.

5. Bulk Power Circuit Breaker Replacement (PIN: 4211)

Bulk power circuit breakers interrupt the flow of electricity through a transmission lines, typically at the 500 kV or 230 kV voltage level. Circuit breakers are essential in preventing equipment damage and public injury when faults occur in their downstream circuits.

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. The Health Index aides in prioritizing and replacing the correct asset population with the highest risk and consequence of failure. The replacement of bulk power circuit breakers is under FERC jurisdiction and is necessary to proactively replace aging 500 kV and 230 kV circuit breakers at substations to enhance transmission system safety and to improve system reliability. This program also increases the reliability of the ISO transmission grid.

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.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$9.770 million.

6. Substation Miscellaneous Equipment Additions & Betterment (PIN: 4756)

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.

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.

The estimated ISO-related direct capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$26.971 million.

7. Bulk Power 500 kV & 230 kV Line Relay Replacement (PIN: 5089)

The Bulk Power 500kV & 230 kV Line Relay Replacement Program and Non-Bulk Substation 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).

The prioritization of relay replacements is based on several 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.

The estimated ISO-related direct capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$14.508 million.

8. Phasor Measurement System Installations (Disturbance Monitoring) (PIN: 6446)

North American Electric Reliability Corporation (NERC) requires each Transmission Owner (TO) to install Disturbance Monitoring Equipment (DME) and report on disturbance data to facilitate analysis of events and verify system models. Each TO 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 230 kV 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.

TOs must be compliant with NERC Protection and Control (PRC) 002-2 by July 1, 2022. NERC PRC-002-2 provides requirements and measurements for TOs 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.

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.

The estimated ISO-related direct capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$7.578 million

9. Transmission Line Rating Remediation (Exempt from Licensing) (PIN: 7298)

SCE conducted a rating assessment of its CAISO controlled and 115 kV 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 and Western Electricity Coordinating Council (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 1,² 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.

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

² Available at http://www.cpuc.ca.gov/gos/GO95/go_95_table_1.html

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 – 500 kV and 230 kV; and (2) Non-Bulk or Sub-transmission – 161 kV, 115 kV, 66 kV, and 55 kV. 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 sub-transmission or distribution.
- Grading; or
- Lowering/removing object (such as a light pole).

Total forecast of TLRR (exempt from licensing) direct capital expenditures between 2021 and 2022 is \$215.409 million and estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$149.388 million.

10. Seismic Mitigations for Transmission Assets (PIN: 7392)

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 Formula Rate Annual Update, 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.

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 to bundle work for efficiency purposes and to minimize outages. Projects related to high-hazards dams with pending FERC reviews will be prioritized accordingly.

Based on the scope and costs to mitigate both transmission towers and lines/corridors and transmission substation structures, SCE forecasts ISO-related capital expenditures of \$27.321 million to perform corresponding mitigations for SCE's transmission assets in the period January 2021 through December 2022.

11. Substation Fence/Gate (Cu Theft) (PIN: 7573)

Substation Fence/Gate (also known as Security Fence and Lights Upgrade) program is focused on deployment of physical security improvements at substations to mitigate the impact on service to customers resulting from theft, vandalism, and other intrusions by upgrading security fence and lights to latest security standards.

The need for ongoing improvement of physical security at SCE substations is driven by their varying levels of impact on electrical systems if a security breach occurs, and by reported incidents of theft, vandalism, and other intrusions. The security monitoring and deterrence deficiencies, and the remote location of many of the 230/66 kV A-Bank substations, increase the potential for unauthorized entry and malicious activity. Improving the physical protection systems at SCE substations continues to be an important initiative to safeguard key systems, information, and facilities, mitigate threats to worker safety, and support reliable delivery of electricity and continuity of business operations.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$6.927 million.

12. Protection of Grid Infrastructure Assets (PIN: 7949)

The Protection of Grid Infrastructure Assets program (previously known as the Physical Security Systems – Electric Facilities Blanket) deploys and standardizes new security systems at SCE and corrects identified deficiencies with access control and monitoring of SCE entry/exit points, critical areas, and critical assets. Each year, Corporate Security reviews emerging threats and security vulnerabilities to develop a prioritized list of electrical facilities designated for security system installations or security systems refresh and enhancements for the next year. Electrical facilities requiring a new security system or security system

component will undergo a structured process to identify specific physical security needs and to develop a system design incorporating SCE security standards, installation and integration with the Edison Security Operations Center (ESOC), and personnel training and awareness. Each deployed security system will be standardized to improve management of replacement assets, maintenance costs, and refresh cycles of security technology components.

To maintain the operation of existing alarm, access control, and security systems at SCE, Corporate Security will first identify which facilities have security systems that are non-operational or are operating at a degraded performance level. Corporate Security will evaluate each security system to be enhanced or refreshed considering current operations, how the site is being utilized, types of assets requiring protection, access controls for population and types of persons at the site, and the required protections associated with the refresh/enhancement.

Completing work needed for NERC CIP-014 Tier 1 substation and associated command centers/switching centers critical asset protection is a priority for 2019 and 2020. NERC CIP-014 work requires many of the same resources as the Protection of Grid Infrastructure Assets program. Consequently, a low level of work for this program was scheduled for prior years. From 2019 to 2023, the focus will be on making security enhancements to control/command centers, major/medium/minor substation enhancement projects, and system replacements and renewals.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$16.971 million.

13. Substation Facility Capital Maintenance (PIN: 7637)

SCE's Substation Capital Maintenance Program seeks to preserve the value of SCE's substation buildings, equipment, and grounds, making them as safe and productive as reasonably possible and 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.

SCE uses Asset Management Methodology, to prioritize capital projects and program expenditures to support SCE's objectives to provide safe, reliable, and affordable electricity to its customers. One of the three main influencing factors under Asset Management Methodology is Facility Condition Index (FCI) that assesses conditions (e.g., age and wear of the building and its systems) and compares the cost to improve them against the cost to replace the building or site. The FCI score, expressed as a percentage, is the ratio of the cost of correcting identified deficiencies to the replacement cost for the facility in whole. A low FCI score is more desirable than a high one. To be more specific, the FCI Score of 0-5.0% translates into Good; 5.1%-10.0% into Fair; 10.1%-29.9% into Poor; and >30% into Critical overall condition characterization. SCE's portfolio FCI score has improved from 23% (Poor condition) in 2013 to 16% in 2016 - improved, but still in Poor condition and, therefore require ongoing capital maintenance. For the 2015 SCE FCI Report, please refer to the attachment. It would not be prudent to replace all aged facilities, for a variety of reasons. FCI is one indicator used by SCE in prioritizing investments. Other conditions and influencing factors must also be considered, as discussed below.

Asset Priority Index (API) rates the relative importance of a facility among the network of facilities required to serve SCE's customer base. A facility's API is used to define a facility's importance in meeting SCE's strategic business intent

and operational performance. Periodically, SCE's Corporate Real Estate (CRE) department consults with SCE leadership from across OUs to rank SCE's facilities. A site is prioritized by its importance and criticality to delivering safe and reliable services. A lower API ranking (i.e., number) indicates a higher priority. An API ranking of three shows a highly needed and important facility, as compared to an API ranking of 98, which would be a non-essential asset. SCE deprioritizes investments in non-essential buildings, such as a general non-electric tool shed, with a Poor FCI condition and a high API ranking. Conversely, investments are prioritized for the most significant facilities, which have comparatively high operational purpose and, therefore, a low API rank. Last, where the FCI and API focus on the condition and criticality of a facility, SCE considers a facility's fitness for purpose, as a way to integrate evolving business conditions, and the ability of a facility to support these changes, into portfolio planning and capital prioritization. This factor considers the unique conditions of a facility and its ability to support current and future operations, such as:

- Changing work methods or equipment (e.g., T&D vehicles or IT data processing machines) and limitations or deficiencies of the current building infrastructure, building design, and site design, which can cause overburdened building systems, non-compliance with current building codes, or poor service reliability conditions.
- Regulations, such as building codes that cannot be achieved in old building or site designs, that pre-dated such regulations, and which conditions have become an increasing concern for safety and operational reliability.
- The current capacity and utilization of buildings or sites (e.g., of parking, office spaces, etc.) versus the forecast growth or contraction and the ability for the facility, to best support the change.

- The ability to consolidate or co-locate functions or uses, to continue to use facilities to their highest and best use or to promote better collaborative work environments.

The forecast for substation capital maintenance is a combination of historical expenditures and a zero-based budget, considering fluctuations in the maintenance activity. The forecasted level of spend is needed for proper preventative maintenance to mitigate negative impacts from the prior delays, including costly repairs and replacements.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$11.689 million.

14. Substation Switchrack Rebuilds (PIN: 7713)

Substation Switchrack Rebuilds activity captures the capital expenditures related to rebuilding existing substation racks based on conditions found in the field, as well as through various analyses including structural and seismic analysis. A substation switchrack is the skeletal/structural system used to support substation assets such as circuit breakers, disconnects, and conductors. Substation structures degrade over time and need to be replaced and/or upgraded. The switchracks/structure needs are initially identified at the scoping job walk, typically driven by the circuit breaker and transformer replacement, and in some cases disconnect switch replacements.

At the scoping job walk the field personnel (operations, construction, maintenance, etc.) and engineering personnel evaluate and determine the project scope. These workers evaluate the condition of foundations, equipment, structures, and working areas/to identify the need to potentially perform a switchrack rebuild project. Prior to pursuing a rebuild project, SCE also considers other potential solutions including, but not limited to, deferring a project, modifying a switchrack

(i.e., structural modification in place or additional grading beneath a switchrack structure), and/or increasing maintenance activity for the circuit breakers and/or transformers.

Switchrack rebuild projects result from the need to replace substation circuit breaker. SCE estimates the costs for each project based on the unique characteristics of each project, and not by using an average cost per project approach. This is because, unlike like-for like replacements of circuit breakers and transformers, switchrack rebuild projects can vary and have unique site-specific challenges, including voltage class, geographic location, property size and footprint, non-SCE original construction, modification of construction standards, local city regulations, space constraints for construction, maintaining service during construction, etc. As a result, using an average cost per project forecast is not meaningful.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$11.800 million.

15. Transmission Maintenance Planned - Overhead Conductor (PIN: 7890)

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. Approximately 2 miles of reconductoring is planned to be applied to three 230 kV transmission circuits in Metro West Grid during 2021-2022 period. In addition, shield wire will be replaced for the Rector – Springville 230 kV transmission line in San Joaquin Grid during this period.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$9.750 million.

16. West of Colorado River CRAS Inland/Devers Extension (PIN: 8284)

As part of the Queue Cluster (QC) 10 studies, generation projects (Q1402 Atlas Solar, Q1403 Harquahala Flats, Q1405 Athos Power Plant, Q1406 Mesaville Solar and Q1407 Mountainview Generating Station Pmax Increase) seeking interconnection to the Eastern Area triggered the need for the West of Colorado River CRAS Inland/Devers Extension. This CRAS monitors multiple 230 kV and 500 kV lines in the West of Devers Area. The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$6.764 million.

17. LADWP AC/DC Filter Replacement (PIN: 3138)

The AC/DC Filter Replacement is a capital improvement project consisting of engineering, materials procurement, installation of four AC & two DC Filter Banks, and upgrading the HVDC Control and Protection at Sylmar Converter Station (SCS) East. The project scope is to upgrade the existing AC/DC filter banks along with control and protection system for the Pacific DC Intertie (PDCI) at Sylmar Converter Station. This project is constructed by LADWP and a contractor with a total estimated cost of \$224 million. The construction of four AC filter banks and two DC filter banks along with demolition of four existing AC filter banks and two existing DC filter banks is performed by LADWP. The design, engineering, equipment procurement, installation of control & protection system, and commissioning the entire project is the contractor's responsibility with the following task:

- Third party consultant shall be employed to perform technical design review and owner's representation.

- All four existing AC filter banks shall be demolished and disposed from the SCS East and West. The new AC filter banks shall be installed exclusively at SCE East.
- The two existing DC filter banks shall be demolished and disposed from the SCE West. The new DC filter banks shall be installed at SCE East.
- The new AC/DC filters shall be seismically qualified as required per LADWP specifications.
- The existing DC line connections between the converters on the SCE East and the DC filters on the SCS West shall be partially removed.
- Two additional shunt reactors shall be installed to minimize the reactive interchange between AC and DC systems.
- The hardware and software of the HVDC control systems shall be upgraded to the latest version of control, monitoring, and protection system for the bi-pole, monopole, AC/DC filters interface, and associated auxiliary equipment.
- The newly commissioned transmission and control system at SCE East shall be in compliance with the last LADWP and NERC/FERC cyber security requirements.
- The new redundant AC/DC voltage dividers, filter bus ground switches, filter sub bank breaker and disconnects, and protections independent of the control system shall be included for the AC/DC filters.
- New Server on Gas Monitoring units shall be installed and commissioned on the existing Converter Transformers for online monitoring.
- The new AC/DC filters and associated equipment shall be integrated, tested, commissioned, and placed in-service.
- Outage duration for testing and commissioning shall be minimized.
- All old filter bank equipment shall be decommissioned.

- The two existing telecommunications buildings at the SCS West shall remain at current location. No changes shall be made to them as they house PDCI participant utility companies' equipment.

In additions, LADWP will perform the following:

- Development of specifications, request for proposals, bids review & selection, contract negotiations, and contract award.
- Engineering support and project management.
- Engineering will issue Construction Work Packages (CWPs) in accordance with Contractor's design and specifications.
- Performing all civil and electrical construction for the AC/DC filter banks.
- Performing the design of overhead transmission lines and modifications to existing structures at Sylmar.
- Quality assurance, maintenance support, and construction inspection.
- Relocating 720 feet of a 30-inch water trunk-line under the project site.
- Providing around a clock security personnel during construction.

The project was placed in service in June 2020 with remaining capital expenditures of \$5.298 million, which represents SCE's 50% share of the project. All the total project cost is projected to go into rate base during this period.

18. September Wildfires CEMA Transmission Restoration and Erosion Control (PIN: 4057)

The Creek fire started on September 4, 2020 in Fresno County and burned more than 379 thousand acres. Once it was safe to do so, SCE personnel inspected the area to assess the damage and began restoration efforts. The Creek fire destroyed several of SCE's 230 kV Transmission structures and lines under CAISO control. SCE activated the Incident Support Team on September 14, 2020 in response to fire restoration activity in the service territory. Damaged Assessment Teams

identified 3 Transmission towers that needed to be replaced and 16 Transmission towers needed repairs. The teams also identified 5 miles of overhead (OH) conductors to be replaced and approximately 10 spans of OH conductor needing repairs. There were approximately 30 towers that needed aerial washing as well.

The Creek fire impacted SCE's Transmission, Distribution, Telecom, and Hydro facilities in the area, including the critical Big Creek facility. It was critical for SCE to begin restoration and quickly restore power to impacted customers and the grid. The decision was to rebuild 5 miles of Transmission OH conductor spans, replaced 3 towers, and repaired to several towers as well as other essential material in-line with SCE's updated standards for High Fire Risk areas for assets that were damaged from the fire. In replacing the damaged OH conductor spans, SCE also had to replace the adjoining OH conductor too, which resulted in slightly more miles of OH conductor spans.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$8.691 million.

19. Riverside Transmission Reliability Project (PIN: 5450)

The Riverside Transmission Reliability Project ("RTRP") is a joint project between SCE and Riverside Public Utilities ("RPU"), the municipal utility department of the City of Riverside. While RPU would be responsible for constructing some of the project's facilities within Riverside, SCE's portion of the project consists of constructing upgrades to its system, including a new 230-kV Substation; certain interconnection and telecommunication facilities and transmission lines in the cities of Riverside, Jurupa Valley and Norco and in portions of unincorporated Riverside County. The purpose of the project is to provide RPU and its customers with adequate transmission capacity to serve

existing and projected load, to provide for long-term system capacity for load growth, and to provide needed system reliability.

In October 2018, the CPUC issued an environmental report that identified a new route alternative, as the environmentally preferred project and proposed an additional underground section of the proposed 230-kV power line. In March 2020, the alternative project with revised scope and an updated cost of \$584 million was approved by CPUC. The scheduled in-service date of the project has been extended from 2024 to 2026.

In June 2020, SCE filed a petition with the FERC seeking authorization to recover SCE's prudently incurred costs if the project is cancelled or abandoned for reasons beyond SCE's control, and inclusion of 100% of the project's network transmission Construction Work In Progress in transmission rate base during the construction period. In September 2020, the FERC issued orders granting SCE's requests. SCE is allowed to seek recovery of 100% of all prudently incurred costs after September 17, 2020 and 50% of prudently incurred costs prior to that date.

The estimated ISO-related capital expenditures for acquiring rights of way (ROW) that are projected to go into rate base in the period January 2021 through December 2022 are \$47.774 million.

20. West of Devers (PIN: 6420)

The West of Devers Upgrade Project (WODUP) consists of upgrading and reconfiguring approximately 48 miles of existing 230 kV transmission lines between the Devers, El Casco, Vista, and San Bernardino substations, increasing the power transfer capabilities. The WODUP is needed to integrate planned renewable generation resources, comply with executed Large Generator Interconnection Agreements (LGIAs) and signed Power Purchase Agreements (PPAs), comply with NERC and WECC transmission reliability planning criteria

and facilitate compliance with California's renewable portfolio standards (RPS) goals.

In August 2016, the CPUC approved the construction of the WODUP. As a result of the delay in receipt of the WODUP's approval from the CPUC, SCE deferred the forecasted timing of project capital expenditures. Office of Ratepayer Advocates (ORA) filed an Application for Rehearing in September 2016 stating that the August 2016 decision failed to follow the California Environmental Quality Act (CEQA) when it approved the WODUP and should have approved an alternative project with an amended scope. In March 2017, the CPUC issued a decision denying ORA's September 2016 Application for Rehearing. This action confirmed SCE's proposed project. In December 2017, SCE awarded the competitive bid for transmission construction, which resulted in a decrease to the expected cost of the WODUP from \$1.075 billion to \$848 million.

The projected in-service date of WODUP is May 2021 with an estimated total project cost of \$740 million in direct capital expenditures, which includes not only non-jurisdictional cost, but also jurisdictional cost beyond the forecast period. The estimated ISO-related direct capital expenditures of \$658.293 million are projected to be placed in plant in service or go into rate base in the period January 2021 through December 2022.

21. Casa Diablo IV Project Interconnection (PIN: 7227)

This project is needed to interconnect the Casa Diablo IV Project to SCE's Casa Diablo 115/33 kV Substation. The scope of the project includes the Casa Diablo IV interconnection in the Bishop Special Protection System (SPS) under the single outage of the Control-Coso-Haiwee-Inyokern 115 kV transmission line, the single outage of the Control-Haiwee-Inyokern 115 kV line, and the simultaneous outage of the Control-Coso-Haiwee-Inyokern and Control-Haiwee-Inyokern 115 kV

lines. Two N60 relays will be also installed at Control 115/55 kV Substation as part of project scope.

The proposed operating date for the specific project is July 2021 and total ISO related direct capital expenditures that are projected to go into rate base during this period are \$12.610 million.

22. Eldorado-Lugo-Mohave (ELM) Upgrade (PIN: 7546)

CAISO approved the Lugo-Eldorado series capacitor and terminal equipment upgrade in its 2012-2013 Transmission Planning Process (TPP) and the Lugo-Mohave series capacitor and terminal equipment upgrade in its 2013-2014 TPP as policy-driven upgrades to relieve deliverability constraints in order to support achievement of California's renewable goals. It will increase power flow through existing transmission lines from Nevada to Southern California and provides renewable integration, deliverability, and reliability benefits. CAISO identified reliability benefits of the project in that it relieves overloads on certain 500kV facilities in the neighboring LADWP's transmission system.

The ELM project would modify SCE's existing Eldorado, Lugo, and Mohave electrical substations to accommodate the increased current flow from Nevada to Southern California; increase the power flow through the existing Eldorado-Lugo, Eldorado-Mohave, and Lugo-Mohave 500 kV transmission lines for the purpose of increasing the amount of power delivered from California's Ivanpah Valley, Nevada, and Arizona to the Electrical Needs Area (ENA) through the SCE system in an effort to meet requirements associated with the California Renewables Portfolio Standard (RPS) by constructing two new 500 kV mid-line series capacitors (i.e., the proposed Newberry Springs Series Capacitor and Ludlow Series Capacitor) and associated equipment; raise transmission tower heights to meet ground clearance requirements; and install communication wire on

SCE's transmission lines to allow for communication between existing SCE substations.

SCE has proposed an expedited schedule and a non-standard review process with the regulatory permitting agencies to meet the current in-service date. During September 2017, SCE awarded the competitive bid for the project which resulted in a decrease to the expected capital forecast for the project.

On May 2, 2018, SCE filed an application for a Permit to Construct (PTC) authorizing SCE to construct electrical facilities known as the Eldorado-Lugo-Mohave Series Capacitor Project.

On January 9, 2019, the CPUC directed SCE to file an amended application for a Certificate of Public Convenience and Necessity (CPCN). SCE submitted its amended application for a CPCN on April 19, 2019. The licensing process to file CPCN delayed the projected construction start date to third quarter of 2020.

Public Advocates Office (PAO) protest resulted in CPUC ruling for an amended CPCN application to be filed (note SCE filed a PTC in May 2018, and then the amended CPCN application April 2019) and this licensing delay deferred construction start date to Q4 2020. Final Decision was voted at CPUC's August 27 Business Meeting, approving the project to move forward. BLM Nevada authorized SCE to proceed with construction under O&M condition until ROW Grant is renewed. Eldorado and Mohave construction started on November 2, 2020. CPUC issued Notice to Proceed (NTP) #1 authorizing work to start at Lugo Substation on Jan 4, 2021. The 60-Day Department of Interior Temporary Suspension of Delegated Authority (SO3395) has been lifted for BLM CA and NPS. BLM CA issued NTP allowing construction at Newberry Springs to commence. BLM Nevada issued ROW Grant Renewal for the 500kV TL.

The proposed operating date for the specific project is June 2022 with an estimated total project cost of \$247 million in direct capital expenditures, which includes not only non-jurisdictional cost, but also jurisdictional cost beyond the

forecast period. Total ISO related direct capital expenditures that are projected to be placed in plant in service or go into rate base during this period are \$197.517 million.

23. Mesa Substation (PIN: 7555)

The Mesa Substation Project consists of replacing the existing 230/66/16 kV Mesa Substation with a new 500/230/66/16 kV substation. The Mesa Substation Project would address reliability concerns by providing additional transmission import capability, allowing greater flexibility in the siting of new generation, and reducing the total amount of new generation required to meet local reliability needs in the Western Los Angeles Basin area. In February 2017, the CPUC issued a final decision approving the Project largely consistent with SCE's proposal and rejected alternative project configurations proposed by CPUC staff.

In October 2017, SCE awarded the competitive bid for the new 230 kV portion of substation construction. SCE updated the expected cost of the Project from \$608 million to \$646 million due to schedule delays and scope changes. Construction of the new 500/230/66/16 kV substation and demolition of the existing 230/66/16 kV substation would occur in phases. Phase 1 would consist of grading and initial site development on the western portion of the project site. Phase 2 would consist of construction of the first half of the new Mesa Substation. During Phase 1 and 2, the existing substation on the eastern portion of the site would remain operational to maintain electrical service to customers during construction. Phase 3 would consist of demolition of the existing 220/66/16 kV substation and construction of the second half of the new substation on the eastern portion of the site. Phase 4 (500 kV substation construction) Request for Proposal (RFP) was issued December 2019 and bids were received February 28, 2020. A winning bid was awarded in May 2020 and SCE's project team is working to determine the logical start date for Phase 4 construction.

The projected operating date for the project is March 2022 with an estimated total project cost of \$641 million in direct capital expenditures, which includes not only non-jurisdictional cost, but also jurisdictional cost beyond the forecast period. The estimated ISO-related direct capital expenditures of \$244.109 million in projected closing to plant in-service or go into rate base in the period January 2021 through December 2022.

24. Magunden-Springville No.1 & 2 Tower Replacement ("Lake Success Towers in Water") (PIN: 7558)

The purpose of Lake Success Project is to develop a long-term solution to reroute Magunden-Springville 230kV No. 1 and 2 lines that cross Lake Success to address the following issues:

- Tower structure integrity –Since 1963, US Army Core of Engineers (USACE) has had the right to inundate the reservoir and SCE’s T/L ROW with water at or below elevation 660 feet.
- Lake’s water level increase –Lower Tule River Irrigation District (LTRID) & USACE’s current plan to increase the water level at Lake Success to 662.5 feet would cause additional area of SCE right-of-way to be submerged.
- GO 95 clearance discrepancies – GO 95 compliance challenges regarding phase to water clearance. SCE Conductor clearance for transmission structures now requires 49 feet over water.
- Public safety –Lake Success visitors have historically been observed anchoring boats to, and diving from SCE towers.

The projected operating date for the project is July 2022 with an estimated total project cost of \$21.096 million in direct capital expenditures, which includes jurisdictional cost beyond the forecast period. The estimated ISO-related capital

expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$14.237 million.

25. Lugo-Victorville 500 kV T/L Special Protection System (“SPS”) (PIN: 7763)

The purpose of this project is to prevent overloads on the jointly owned Lugo-Victorville 500 kV transmission line. This SPS trips the Transition Cluster (“TC”) generation projects for the N-1 loss of the Eldorado-Lugo 500 kV line and the N-2 loss of the Eldorado-Lugo and Lugo-Mohave 500 kV transmission lines. This project was approved by the CAISO in an executed LGIA. The proposed operating date is July 2022 and estimated ISO-related direct capital expenditures that are projected to go into rate base are during this period \$12.642 million.

26. Substation Physical Security Enhancements (PIN: 7820)

In 2014, NERC developed physical security regulations to require utilities to protect critical substations from attack that could cause widespread outages in the bulk electrical system. NERC CIP-014 addresses greater protection of key physical assets at the most critical BES facilities to reduce the overall vulnerability of these facilities to physical attacks.

The stated purpose of the NERC CIP-014 Standard and its requirements is to identify and protect transmission stations and substations, and their associated primary control centers, which if rendered inoperable or damaged because of a physical attack, could cause widespread instability, uncontrolled separation, or cascading within an interconnection.

The NERC CIP-014 Standard for physical security requires a high-level threat and vulnerability analysis to uncover potential threats and weaknesses, and the corresponding impacts should an attack take place on a critical grid connection. The NERC CIP-014 Standard provides a structured framework whereby utilities must comply with the six requirements described in table below.

Table 2
NERC CIP-014 Requirement Description

Requirement	Description/Goal
R1	Applicability and Risk Assessments – Initial assessment and identification of critical facilities
R2	Unaffiliated Review – Independent review of initial (R1) risk assessment
R3	Control Center Notification – Coordination between operator and owner
R4	Threat and Vulnerability Assessment – Evaluation of potential threats/vulnerabilities of a physical attack
R5	Security Plan – Development and implementation of a physical security plan
R6	Unaffiliated Review – Third party assessment of R4 and R5

Under Requirements R1 through R3, SCE must perform an initial risk assessment (R1) to identify critical assets which, if compromised or attacked, could lead to one of the events described above, and those results must be reviewed by an independent third party (R2) and then communicated to SCE's control/switching centers (R3). Requirements R4 through R6 require a tailored assessment and evaluation of potential threats and vulnerabilities to each of the identified critical assets (R4), and then development and implementation of a plan (R5), corroborated by an independent third party (R6), to protect those identified assets from physical threats. Corporate Security is responsible for completing R4 through R6 requirements.

The drivers for the NERC CIP-014 project are to:

- Reduce the overall susceptibility of the power grid to physical attacks.
- Protect transmission substations and associated primary control centers.
- Deploy a multi-layered approach to detect, deter, delay, respond and monitor potential intrusions and attacks with the creation of uniform standards, processes, and procedures.
- Demonstrate steps to address physical security risk and vulnerabilities related to the reliable operation of the BES.

On April 16, 2013, attackers severed six underground fiber-optic lines at PG&E's Metcalf substation in San Jose before firing more than 100 rounds of ammunition at substation equipment using high-powered rifles. The apparent acts of sabotage did not result in power outages. However, the attacks disabled large transformers (which took 27 days to repair) and some 911 and landline telephone services, causing more than \$15 million in damages, and highlighting the vulnerability of the electric system to this type of action. There is widespread agreement among state and local officials and utility operators that critical substations are vulnerable to attack from both personally-motivated attackers and terrorists, and that the potential effects of such an attack on the U.S. economy and the well-being of those living in the affected areas could be devastating.

An attack has a high probability of disrupting the electric grid despite the high level of grid resiliency. In the last 10 years, international terrorists have attacked over 500 substations overseas. In 2002, two Al-Qaeda sympathizers were indicted for conspiring to bomb substations and a National Guard armory in southern Florida. In 2014, three militia members were arrested in Georgia buying improvised explosive devices (IED) to target critical infrastructure, including the power grid. In the last five years, there have been over 30 reported incidents of persons firing weapons at substations or control buildings, and six improvised explosive devices have been used against a substation or control building. While none resulted in electrical grid disruption, they highlight the inherent vulnerability of these facilities and the need for protective measures commensurate to the criticality and the potential risk.

The estimated ISO-related portion is \$10.006 million that will go into rate base in the period January 2021 through December 2022.

27. Physical Security Enhancement Projects (Tiers 2 & 3) (PIN: 8042)

Project objective is to security measures at most critical facilities based on the criticality of need and the potential impact of a security breach. The Tier Program supports the efforts of providing safe and reliable service to our customers by improving the protection of critical assets, buildings, and people around electric facilities. Deployment of security systems at these facilities is prioritized based on operational need and evolving threats such as theft, vandalism, and security breaches. Security enhancements include perimeter intrusion detection, integrated access control, alarm management with ESOC and video surveillance. This program implements a set of standards to ensure fiscally responsible decision making process directly tied to risk mitigation.

Although work associated with the Tier Program was scheduled to begin in 2018, SCE was able to test new and more cost-effective security systems after the filing of the 2018 General Rate Case (GRC), prompting the rescheduling of implementation to 2019. The substation tiers are:

- Tier 1 – Substations identified in CIP-014 Risk Assessment (including Pre-CIP-014 Pilot Sites).
- Tier 2 – 500 kV with five or more Network Connections or load > 1,000 MW or Generation > 1,200 MW.
- Tier 3 – 500 kV with five or more Network Connections OR 220 kV with eight Network Connections, OR 220 kV and load > 1,000 MW or Generation > 1,200 MW.
- Tier 4 – Additional A & AA-bank substations identified by SCE AND Substations not identified in Tiers 1 -3.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2021 through December 2022 are \$14.555 million.

28. Annual Transmission Reliability Assessment 2016 - Protection Upgrades (PIN: 8077)

Install protection upgrades to comply with NERC TPL 001-4 (Transmission System Planning Performance Requirements), which went into effect January 1, 2016. NERC Transmission Planning Standards 001-4 requires mitigations for the TPL violations and persistent faults identified as part of Annual Transmission Reliability Assessment (ATRA) 2016.

In coordination with CAISO's TPP, SCE performs an ATRA for its portion of the CAISO-controlled grid. This assessment is designed to:

- Evaluate the performance of the SCE transmission system under peak and off-peak conditions for near-term and long-term planning horizons.
- Determine transmission constraints under stressed system conditions.
- Identify upgrades needed to maintain the reliability of the transmission system and comply with NERC Reliability Standards, WECC Regional Business Practice, CAISO Planning Standards, and SCE's transmission planning criteria.

SCE's ATRA is performed in parallel with the CAISO TPP under the CAISO's FERC jurisdictional tariff. SCE's Grid Reliability Projects are identified in the CAISO TPP and subject to review and approval by the CAISO Board of Directors and cost recovery based upon the CAISO Transmission Access Charge (TAC).

The proposed operating date for the specific project is June 2022 and total ISO related direct capital expenditures that are projected to go into rate base during this period are \$20.223 million.

29. Moorpark-Pardee 230 kV No.4 Circuit (PIN: 8104)

This project addresses a generation capacity deficiency that can cause a voltage collapse in the Moorpark local capacity subarea. The project involves stringing a fourth Moorpark-Pardee 230 kV circuit approximately 26 miles on existing structures in SCE's transmission right-of-way. This includes installing terminal equipment at Moorpark and Pardee Substations and relocating existing circuit terminations in the 230 kV switchrack at Moorpark Substation.

The projected operating date for the project is April 2022 with an estimated total project cost of \$73.4 million, which includes both non-jurisdictional cost and jurisdictional costs beyond the forecast period. The estimated ISO-related direct capital expenditures of \$52.811 million are projected to go into rate base in the period January 2021 through December 2022.

30. Red Bluff 2nd 500/230 kV AA Bank (Deliverability Network Upgrade) (PIN: 8163)

Proposed project scope will include installation of a second 500/230 kV 'AA' transformer bank at Red Bluff Substation. This will also require the need to modify the existing Special Protection System (SPS) to trip generation under an N-1 of one transformer bank. Upgrade was identified in the Q643AE/TOT486 executed Generator Interconnection Agreement (GIA) for full deliverability of Desert Harvest's 150 MW solar photovoltaic renewable generation.

The proposed operating date is November 2021 with an estimated total project cost of \$19.1 million in direct capital expenditures, which includes jurisdictional cost beyond the forecast period. The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are \$14.489 million.

31. Colorado River Substation Expansion – Installation of the 2nd AA 1120MVA 500/230 kV transformer bank (PIN: 8169)

The FERC conditionally accepted on February 4, 2011, the “Standard Large Generator Interconnection Agreement (LGIA) Among Palo Verde Solar II, LLC and Southern California Edison Company and California Independent System Operator Corporation” for interconnection of a 1,000 MW solar thermal generating facility to SCE’s transmission system at the proposed Colorado River 230 kV Substation.

Colorado River expansion will provide capacity for up to 2,000 MW of new generation resources at Colorado River. The expansion will include both reliability network upgrades and delivery network upgrades. Colorado River was originally proposed to be configured as a 500-kV switchyard as a component of Devers-Palo Verde 2 (DPV2) and designed to be expanded as additional resources requested interconnection to the substation. Additional renewable generation projects have requested interconnection to the Colorado River 500 kV switchyard, including solar generation projects in the CAISO’s transition cluster and additional interconnection requests for solar generation in subsequent queue clusters. Consequently, Colorado River needs to be expanded to accommodate such requests. The CPUC has previously approved Colorado River, however, the proposed expansion will require enlargement of the previously approved project’s footprint and will include installation of a second 500/230 kV ‘AA’ transformer bank at Colorado River Substation. Upgrade was initially identified in Q294/TOT276 executed GIA.

The proposed operating date is December 2021 with an estimated total project cost of \$19.6 million in direct capital expenditures, which includes both non-jurisdictional cost such as IT-Telecomm and jurisdictional cost beyond the forecast period. The estimated ISO-related direct capital expenditures that are projected to be placed in service during this period are \$14.994 million.

For further details such as monthly budgeted direct expenditures, please see the following work papers: “WP-Schedule 10-Summary of ISO Capital Expenditures – Incentive Projects”, “WP-Schedule 16-Summary of ISO Capital Expenditures - Non-Incentive Projects”, and “WP-Schedule 10 & 16.”