During the period January 2020 through December 2021, SCE forecasts:

- $794 million in ISO non-incentive network transmission closings to rate base (including $399 million in ISO Blanket Specifics closings),
- $484 million in FERC incentive rate qualified CWIP expenditures, and;
- $1,023 million of CWIP Expenditures closing to rate base

In addition to the numerous but relatively small transmission projects, there are 32 significant transmission projects (each $5 million or greater in ISO-related costs) that are expected to be added to rate base in the period January 2020 through December 2021 – 14 Blanket Specifics (items 1 through 14 below), 17 Specific non-incentive projects (items 15 through 31 below), and four Specific incentive projects (items 16, 19, 21, and 32 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 2020 and 2021
(Nominal $Millions)

No.	PIN	Project	FERC CWIP	FERC Non-CWIP	Total
1	3362	Critical Infra Spare - FERC Spare Transformer Equipment Program (STEP)/ Emergency Spares	-	18.729	18.729
2	3364	Transmission Tower Corrosion Program	-	27.047	27.047
3	3364	Transmission Grid-Based Maintenance		17.340	17.340
4	4211	Replace Bulk Power Circuit Breakers	-	6.137	6.137
5	4756	Substation Miscellaneous Equipment Additions & Betterment	-	33.196	33.196
6	5089	Bulk Power 500kV & 220kV Line Relay Replacement	-	13.287	13.287
7	6446	Phasor Measurement System Installations	-	5.912	5.912
8	7298	Transmission Line Rating Remediation	-	154.671	154.671
9	7392	Seismic Assessment and Mitigation Program for Transmission Assets	-	34.881	34.881
10	7949	Protection of Grid Infrastructure Assets	-	13.617	13.617
11	7637	Substation Facility Capital Maintenance	-	9.815	9.815
12	7666	CRAS Program - Phase 1: Colorado River Corridor RAS	-	9.581	9.581

13	7888	Transmission Maintenance Planned - Pothead Replacement	-	5.457	5.457
14	8224	Transmission Enhanced Overhead Inspections (EOI) Capital Remediations	-	19.908	19.908
15	3138	LADWP AC/DC Filter Replacement	-	85.876	85.876
16	6420	West of Devers Upgrade Project (WODUP)	639.256	9.563	648.819
17	6791	Lugo 500 kV Substation breaker installation for No. 1AA & No. 2AA	-	7.191	7.191
18	7227	Casa Diablo IV Project Interconnection	-	8.822	8.822
19	7546	Eldorado-Lugo-Mohave (ELM) Upgrade	144.724	10.470	155.194
20	7547	Eldorado-Mohave and Eldorado-Moenkopi 500kV Line Position Swap	-	11.724	11.724
21	7555	Mesa Substation	228.145	5.821	233.966
22	7763	Lugo-Victorville 500 kV T/L SPS	-	11.945	11.945
23	7820	Substation Physical Security Enhancements Project[1]	-	47.445	47.445
24	7884	Cerritos Channel Relocation Project	-	26.467	26.467
25	7959	Rector Substation Maintenance and Test Building Improvements Program	-	6.720	6.720
26	8029	Lugo - Victorville 500kV Transmission Line Thermal Overloads Project	-	9.201	9.201
27	8077	Annual Transmission Reliability Assessment 2016 - Protection Upgrades (San Joaquin Region)	-	9.707	9.707
28	8088	Harry Allen – Eldorado 500 kV T/L Project	-	17.478	17.478
29	8090	Eldorado – Sloan Canyon 220 kV Interconnection	-	6.290	6.290
30	8104	Moorpark-Pardee 230 kV No. 4 Circuit	-	65.764	65.764
31	8163	Red Bluff 2nd 500/220 kV AA Bank (Deliverability Network Upgrade)	-	15.787	15.787
32	8169	Colorado River Substation Expansion – Installation of the 2nd AA 1120MVA 500/220kV transformer bank	9.720	-	9.720
33	Various	Less than $5m each	1.446	67.673	69.119
		Total	**1,023.291**	**793.522**	**1,816.813**

1. 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

[1] PIN 7820 Substation Physical Security Enhancements Project is split between Blanket Specifics with $2.935 million and Specific non-incentive with another $44.510 million in ISO related capital additions to rate base (*see* WP Schedule 16 – Summary of ISO Cap Expenditures Non-Incentive Projects).

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. 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 $18.729 million.

2. 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 $27.047 million.

3. 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 $17.340 million.

4. **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 220 kV voltage levels. 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 220 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 2020 through December 2021 are $6.137 million.

5. **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 2020 through December 2021 are $33.196 million.

6. **Bulk Power 500 kV & 220 kV Line Relay Replacement (PIN: 5089)**

The Bulk Power 500kV & 220kV 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 2020 through December 2021 are $13.287 million.

7. 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 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.

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 2020 through December 2021 are $5.912 million

8. 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.

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

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) Sub-transmission – 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 131D 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 2020 and 2021 is $210.606 million and estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are $154.671 million.

9. 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 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.

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 $34.881 million to perform corresponding mitigations for SCE's transmission assets in the period January 2020 through December 2021.

10. 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 2020 through December 2021 are $13.617 million.

11. 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 2020 through December 2021 are $9.815 million.

12. C-RAS Program Phase 1: Colorado River Corridor RAS (PIN: 7666)

Project objective is to install Centralized Remedial Action Scheme (C-RAS) at Colorado River Substation for monitoring No.2AA 500/230 kV Transformer Bank, Red Bluff No.'s 1 & 2 500 kV transmission lines; and transfer trip to generation plants Genesis I, Genesis II, Black Creek, and Dracker to maintain stability. The scope of this project is to install twelve N60 relays (six each for CRAS-A and CRAS-B) for monitoring No.2AA Transformer Bank, Red Bluff No.'s 1&2 500 kV lines; and transfer trip to above generation plants connected to the 220 kV switchrack. The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2020 through December 2021 are $9.581 million.

13. Transmission Maintenance Planned - Pothead Replacement (PIN: 7888)

Regarding 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.

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 capital expenditures for this program that are projected to go into rate base in the period January 2020 through December 2021 are $5.457 million.

14. Transmission Enhanced Overhead Inspections (EOI) Capital Remediations (PIN: 8224)

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 workpaper.

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.

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 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.

The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2020 through December 2021 are $19.908 million.

15. 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 will be constructed by Los Angeles Department of Water and Power (LADWP) and a contractor with a total estimated cost of $180 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 will be performed by LADWP. The design, engineering, equipment procurement, installation of control & protection system, and commissioning the entire project will be 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 SCS East;
- The two existing DC filter banks shall be demolished and disposed from the SCS West. The new DC filter banks shall be installed at SCS 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 SCS 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 upgrades 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 SCS 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 Serveron Gas Monitoring units shall be installed and commissioned on the existing Convertor 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 Converter Station;
- 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 proposed operating date is December 2020 with estimated ISO-related direct capital expenditures of $85.876 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.

16. West of Devers (PIN: 6420)

The West of Devers Upgrade Project (WODUP) consists of upgrading and reconfiguring approximately 48 miles of existing 220 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 December 2021 with estimated ISO-related direct capital expenditures of $648.819 million projected to go into rate base in the period January 2020 through December 2021.

17. Lugo 500 kV Substation breaker installation for No. 1AA & No. 2AA (PIN: 6791)

Currently, both No. 1AA and No. 2AA 500/230 kV transformer banks at Lugo substation are connected to the North and South Buses (respectively) via a bank-on-bus configuration. This configuration violates SCE's existing Transmission Planning Criteria. The project will improve operational flexibility, simplify future additions, and minimize the loss of station capacity during planned outages. The proposed operating date is December 2021 with estimated ISO-related direct capital expenditures of $7.191 million. All the amount is projected to go into rate base during this period.

18. 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 March 2021 and total ISO related direct capital expenditures that are projected to go into rate base during this period are $8.822 million.

19. 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 in order 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.

The proposed operating date for the specific project is December 2021 and total ISO related direct capital expenditures that are projected to go into rate base during this period are $155.194 million.

20. Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Position Swap (PIN: 7547)

This project is to remediate thermal overloads on Lugo-Victorville 500 kV Line caused by adjacent transmission circuits contingency of the Eldorado- Lugo and Eldorado- Mohave 500 kV lines. Initially, this project involved relocating six (6) miles of the Eldorado-Lugo 500 kV line to obtain a minimum separation of 250 feet from the Eldorado-Mohave 500 kV line to remove the two circuits as a credible adjacent transmission contingency. Since the approval of this project, SCE has found a better alternative to re-routing six miles of transmission line. By swapping line positions between the Eldorado-Lugo and Eldorado-Moenkopi 500 kV lines, the same objective could be achieved. This alternative would have a lower cost as well as a shorter lead time for completion. Work will be required at Eldorado Substation and approximately 8 miles south of Eldorado Substation on the Eldorado-Mohave and Eldorado-Moenkopi 500 kV lines. The project was placed in service in January 2018 and total ISO related direct capital expenditures that are projected to go into rate base during this period are $11.491 million.

21. Mesa Substation (PIN: 7555)

The Mesa Substation Project consists of replacing the existing 220/66/16 kV Mesa Substation with a new 500/220/66/16 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 220 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 500/220/66/16 kV substation and demolition of the existing 220/66/16 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 in order 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 estimated ISO-related direct capital expenditures of $233.966 million in projected closing to plant in-service in the period January 2020 through December 2021.

22. 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 May 2021 and estimated ISO-related direct capital expenditures that are projected to go into rate base are during this period $11.945 million.

23. 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 in order 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.

Total forecast of NERC CIP-14 Substation Physical Security Enhancements capital expenditures projected to go into rate base between 2020 and 2021 is $47.666 million and estimated ISO-related portion is $47.445 million.

24. Cerritos Channel Relocation Project (PIN: 7884)

The Port of Long Beach (POLB) requested SCE to relocate SCE facilities crossing the Cerritos Channel to accommodate a larger class of container ship in a letter from the Port on January 8, 2015. SCE's relocation is related to the Gerald Desmond Bridge replacement being done by the POLB for the same purpose. SCE's relocated facilities will need to provide a minimum air draft clearance for 205' (plus any applicable electrical or other required clearances). SCE lines (two 220 kV, six 66 kV, one 12 kV and one fiber wrap) that cross the Cerritos Channel currently provide approximately 150-foot clearance. Proposed project scope includes removal of the 220 kV circuits from Long Beach Substation to Harborgen Substation and removal of above ground structures at the Long Beach 220 kV switchyard, including abandoned equipment in the Mechanical Electrical Equipment Room (MEER). Proposed operation date is March 2021 with estimated ISO-related direct capital expenditures of $26.467 million projected to go into rate base between 2020 and 2021.

25. Rector Substation Maintenance and Test Building Improvements (PIN: 7959)

SCE operates approximately 900 substations. The T&D crews that perform maintenance and testing are strategically located throughout the service territory in order to best access these substations. Staff are in buildings that, initially, were built as a temporary solution or they are in permanent facilities that were not built to adequately support a safe work environment. T&D evaluated all maintenance and test work function locations and identified six substations as priority for improvement. The six in scope for this project were built between 1955 and 1975. The six substations are: Antelope 500/220/66 kV, Mesa 220/66/16 kV, Pardee 220 kV, Devers 500/220/115/13.80 kV, Santa Clara 220/66 kV, and Rector 220/66/12 kV substation. Few renovations to these buildings have been made since they were originally constructed. Test and maintenance operations, at the six identified substations, are performed in separate areas of the site. Sometimes, crew members work at different substation locations due to the lack of space to accommodate the entire crew. Current storage facilities do not provide secure protection of equipment. In some instances, valuable testing parts and equipment are stored in temporary trailers or are not adequately protected from the environment. Many of the substations do not have adequate shop and storage spaces for the crews to perform their work or store critical equipment. This makes it difficult for workflow continuity and communication between the test and maintenance groups. Co-locating the test and maintenance functions within one building, at each of these six sites, will improve efficiencies to workflow and communication, reduce downtime, and efficiently bring critical services to the system. Based on preliminary investigation, SCE identified deficient building conditions such as:

- The building areas cannot support productive working conditions (e.g., no break areas, lack of adequate restrooms).
- Given the age and type of construction, some buildings likely have lead or asbestos in the walls, ceilings, or floor tiles.
- The structural integrity of buildings is poor due to the age of some buildings.
- Buildings are not compliant with modern accessibility or building system regulations (e.g., lighting).

The Substation Maintenance and Test Building Program will address the areas of risk, at the six existing substations, that could have a direct impact on safety and service reliability. Given the: (1) age and condition of existing buildings, (2) productivity issues with crews working in poor building conditions and separate locations, and (3) limited space and storage, it is prudent to build a test and maintenance facility, at each of the six identified substations, which is tailored to its specific site conditions. For this project, SCE will:

- Design and develop an efficient site plan to include safe vehicular access, circulation, and parking.
- Obtain required studies (e.g., engineering and environmental), permits, and approvals.
- Prepare the site (e.g., excavation and/or grading) for circulation, run-off and water management, and utilities; secure the site for construction.
- Construct a test and maintenance building (approximately 13,000 square feet), at each of the six identified substations, with maintenance shops, test benches, employee work areas, meeting areas, and rest and break rooms.
- Construct covered parking for SCE trucks. Construct employee parking areas.

SCE forecasts total expenditures of $11.621 million for Rector Substation whose capital spend is projected to go into rate base by 2021. The proposed operating date is December 2020 and $6.720 million out of the total spend amount is ISO related.

26. Lugo - Victorville 500 kV Transmission Line Thermal Overloads Project (PIN: 8029)

Thermal Overloads on Lugo - Victorville 500 kV Transmission Line can occur during N-2 loss of either Eldorado – Lugo 500 kV with Eldorado –Mohave 500 kV (Category C) or Eldorado – Lugo 500 kV with Lugo –Mohave 500 kV.
To remediate the thermal overloads, the project proposes to replace Lugo Substation’s three 500kV circuit breakers (CBs) (CB#762, 862, 962), six 500kV

disconnects (#761, 763, 861, 863, 961, 963), terminal equipment and line drop at position 6, conductor on CB #862, legs on CB #762, 862, & 962, and 500kV wave trap. This will increase ratings measured lower than 4000 Amps normal and 4500 Amps 4-hour emergency rating. Conductors on CB #762, 862, 962, and Pos. 6 drop currently have 5000A 4-hour emergency ratings. The proposed operating date for the specific project is September 2021 and total ISO related direct capital expenditures that are projected to go into rate base during this period are $9.201 million.

27. Annual Transmission Reliability Assessment 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 March 2021 and total ISO related direct capital expenditures that are projected to go into rate base during this period are $9.707 million.

28. Harry Allen – Eldorado 500 kV Transmission Line Project (PIN: 8088)

The CAISO proposed and approved an economic driven project known as the Harry Allen-Eldorado 500 kV Transmission Project ("HAETP"). The Project consists of approximately 59 miles of a new 500 kV transmission line between NV Energy's Harry Allen 500 kV Substation and the jointly owned Eldorado 500 kV Substation; both substations are located in southern Nevada. On January 11, 2016, the CAISO selected DesertLink, LLC, a wholly owned subsidiary of LS Power Associates, L.P., as the approved project sponsor to finance, construct, own, operate, and maintain the Harry Allen-Eldorado project. SCE's project scope includes installation of facilities for a new 500 kV switchrack position to terminate the Eldorado-Harry Allen 500 kV transmission line and installation of a new 100 MVAR shunt line reactor and appurtenant equipment at Eldorado Substation. The proposed operational year for the Project is June 2020 with an estimated ISO-related direct capital expenditure of $17.478 million is projected to go into rate base in the period January 2020 through December 2021.

29. Eldorado – Sloan Canyon 220 kV Interconnection (PIN: 8090)

Valley Electric Association, Inc. ("VEA") requested interconnection of the Bob Switch to SCE-owned Eldorado 220 kV Switchyard inside the co-owned Eldorado 500/220 kV Substation. VEA is in the midst of expanding its transmission system to enable them to move power between its customers, power producers, and the CAISO.

On September 14, 2017, VEA sold its interest in the Bob Switch Station and the Bob Switch-Eldorado 220 kV Transmission Line to GridLiance West Transco LLC the Connecting Customer. The project was placed in service in December 2019 and estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are $6.290 million.

30. 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 February 2021 with estimated ISO-related direct capital expenditures of $65.764 million in projected closing to plant in-service in the period January 2020 through December 2021.

31. Red Bluff 2nd 500/220 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 April 2021 and estimated ISO-related direct capital expenditures that are projected to go into rate base are during this period $15.787 million.

32. Colorado River Substation Expansion – Installation of the 2nd AA 1120MVA 500/220kV 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 220 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 500/220 kV 'AA' transformer bank at Colorado River Substation. Upgrade was initially identified in Q294/TOT276 executed GIA.

The proposed operating date is September 2021 and estimated ISO-related direct capital expenditures that are projected to go into rate base are during this period $9.720 million.

For further details, 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.”