During the period January 2019 through December 2020, SCE forecasts:

- $777 million in ISO non-incentive network transmission closings to plant in-service (including $366 million in ISO Blanket Specifics closings),
- $649 million in FERC incentive rate qualified CWIP expenditures, and;
- $63 million of CWIP Expenditures closing to plant in-service

In addition to the numerous but relatively small transmission projects, there are 30 significant transmission projects (each $5 million or greater in ISO-related costs) that are expected to be placed in service in the period January 2019 through December 2020 – ten Blanket Specifics (items 1 through 10 below), 20 Specific non-incentive projects (items 11 through 30 below), and two Specific incentive projects (items 13 and 20 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 Closing to Plant In-Service between 2019 and 2020
(Nominal $Millions)

No.	PIN	Project	FERC CWIP	FERC Non-CWIP	Total
1	3362	Critical Infra Spare - FERC Spare Transformer Equipment Program (STEP)/ Emergency Spares	-	20.288	20.288
2	3364	Transmission Grid-Based Maintenance (Tower Corrosion)	-	22.300	22.300
3	4211	Replace Bulk Power Circuit Breakers	-	5.934	5.934
4	4756	Substation Miscellaneous Equipment Additions & Betterment	-	41.551	41.551
5	5089	Bulk Power 500kV & 220kV Line Relay Replacement	-	14.331	14.331
6	5210	Substation Transformer Bank Replacement Program (AA-Bank & A-Bank)	-	25.791	25.791
7	7298	Transmission Line Rating Remediation	-	168.937	168.937
8	7392	Seismic Assessment and Mitigation Program for Transmission Assets	-	9.788	9.788
9	7454	Physical Security Systems - Electric Facilities	-	11.153	11.153
10	7637	Substation Facility Capital Maintenance	-	10.777	10.777

11	3138	LADWP DC Electrode Replacement	-	32.441	32.441
12	3138	LADWP AC/DC Filter Replacement	-	89.637	89.637
13	6420	West of Devers Upgrade Project (WODUP)	14.055	12.539	26.594
14	6791	Lugo 500 kV Substation breaker installation for No. 1AA & No. 2AA	-	5.406	5.406
15	6824	La Fresa Sub (Phase 2 Scope): Install new MEER building	-	11.136	11.136
16	7120	Chino 230/66 kV: Bank on Circuit Breaker Project	-	25.998	25.998
17	7227	Casa Diablo IV Interconnection Project	-	5.507	5.507
18	7518	Springville Sub: Redesign high side feed from bank on bus to double CB at 220kV position 4 equipped with two (2) new 3000A 220kV CB's and disconnects.	-	7.539	7.539
19	7547	Eldorado-Mohave and Eldorado-Moenkopi 500kV Line Position Swap	-	11.491	11.491
20	7555	Mesa Substation	45.826	8.832	54.658
21	7666	C-RAS Program Phase 1: Colorado River Corridor RAS	-	5.862	5.862
22	7763	Lugo-Victorville 500 kV T/L SPS	-	11.914	11.914
23	7820	Substation Physical Security Enhancements Project[1]	-	48.234	48.234
24	7884	Cerritos Channel Relocation Project	-	25.122	25.122
25	7959	Rector Substation Maintenance and Test Building Improvements Program	-	5.612	5.612
26	8009	Northern Area CRAS to Tehachapi CRAS	-	6.044	6.044
27	8042	Substation Physical Security Enhancements (Tiers 2-4)	-	17.908	17.908
28	8088	Harry Allen – Eldorado 500 kV T/L Project	-	14.967	14.967
29	8090	Bob Switch to Eldorado 220 kV Interconnection	-	7.985	7.985
30	8104	Moorpark-Pardee 230 kV No. 4 Circuit	-	26.558	26.558
31	Various	Less than $5m each	3.654	61.535	65.189
		Total	**63.535**	**773.117**	**836.652**

1. Critical Infrastructure Spares (PIN: 3362)

Substation equipment controls the flow of electricity to customers. Therefore, when equipment and parts needs to be replaced, delays must be minimized. SCE must maintain an inventory of equipment that requires a long lead-time for ordering, especially as the infrastructure ages faster than it can be replaced. This inventory enables SCE to reduce outage time at the substation and minimize the customer minutes of interruption caused by an unplanned major equipment failure.

[1] PIN 7820 Substation Physical Security Enhancements Project is split between Blanket Specifics with $7.953 million and Specific non-incentive with another $40.281 million in ISO related capital additions to rate base (*see* WP Schedule 16 – Summary of ISO Cap Expenditures Non-Incentive Projects).

Examples of the equipment maintained in inventory at substations are transformers, circuit breakers, disconnects, and other similar equipment. Spare transformers are also used temporarily to address unforeseen increased load requirements at various substations during peak summer months.

Large transformers typically have delivery lead time of over six months or one year. An AA- (500/220 kV) or A- (220/66 kV or 220/115 kV) Bank transformer failure results in a significant reduction of system reliability and rapid replacement of failed transformers is essential to grid safety, efficiency, and reliability. Therefore an adequate number of readily available spare transformers is required.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are $20.288 million.

2. Transmission Grid-Based Maintenance (Tower Corrosion) (PIN: 3364)

Transmission Grid-Based Maintenance includes Transmission Tower Corrosion and Transmission Tower Lead Paint Remediation. Transmission towers are among SCE’s largest and most important assets. SCE operates around 27,000 towers across the SCE territory including out of state inner-ties. These structures and lattice towers are mostly comprised of galvanized, painted steel and typically range from 50 to 300 feet in height. Many of these structures were built between 1950 and 1990, while many others in the system actually predate 1950. As of the year 2020, 93% of SCE’s tower portfolio will be 30 or and older and subject to some level of corrosion. Corrosion has been observed particularly in towers where the protective paint coating has deteriorated. Once a galvanized tower begins to corrode the corrosion advances exponentially. For example, a tower with less than 5 percent rust at age 30 can oxidize to the point of failure within 10 years.

There are four phases of transmission tower corrosion:

- Phase I--<5% surface stain rust: Damage is not structural. Rust appears on edges and bolts.
- Phase II--Abrasive rust: Rust appears on bolts, edges, sub surface and horizontal flat areas. Rust falls off on touch.
- Phase III--Extensive, abrasive rust above ground and sub-surface with 10% to 25% of cross sectional area steel reduction.
- Phase IV--Structure failure with more than 30% of cross sectional area steel reduction in major load bearing members.

SCE's mitigation plan is comprised of four activities:

(i) Inspections and testing underway on SCE's tower portfolio. Initial projections estimate that approximately 2700+ towers could be ranked in corrosion phases II or III. Inspections will be prioritizing based on age of the tower, climate and soil condition.

(ii) Corrosion phase II entails above-ground and sub-surface structural repairs to the tower, and replacing corroded steel members, footings, nut and bolts.

(iii) Phase III necessitates surface preparation and tower coating. Towers are cleaned and given an application of protective coating which prevents corrosion and seals tower for up to 20-25 years, thus extending the useful life of the asset.

(iv) If a tower is in phase IV and we are unable to salvage the structure by conventional repairs or the coating method, the structure will be replaced.

An ongoing inspection and testing program will be implemented annually to identify further scope. These inspections will include above and below ground observations and testing, and will be an ongoing requirement similar to our intrusive pole inspections. Without mitigation, especially in more extreme weather areas, SCE's lattice towers will continue to corrode until tower collapse is imminent. Tower failure is a serious public safety and reliability risk. Identified corrosion is a serious precursor to tower failure and needs to be actively addressed.

SCE also identified a potential issue with lead-based paint (LBP) based on benchmarking with Pacific Gas & Electric (PG&E) and initiated a system-wide assessment of 26,694 towers. Approximately 1,400 painted towers were identified, and 515 of these were found to have LBP. Paint and soil sample results were analyzed against the California Environmental Protection Agency Human and Ecological Risk Office (HERO) thresholds. SCE developed a prioritization scale with criteria adapted from PG&E based on exposure and land use. 160 towers (159 in Tier 1 and 1 in Tier 2) fell into the upper two tiers requiring the most attention. Tier 1 towers have potential human impacts (e.g., located near residences, schools, etc.) and Tier 2 towers have potential ecological repercussions (e.g., in close proximity to wetlands).

The mitigation plan is comprised of three activities: structural repairs, scraping and painting towers, and soil mitigation. This comprehensive approach allows for repairs to restore structural integrity, use of non-lead based coating to encapsulate any residual LBP and serve as a protective coating to extend tower life, and removal of LBP impacted soil beneath the towers. Overall, the mitigation plan is estimated for 4 years.

- 2019 (Year 1) – additional inspections, resource allocation, bids, engineering reviews
- 2020 (Year 2) - structural repairs, painting, soil mitigation
- 2021 (Year 3) – structural repairs, painting, soil mitigation
- 2022 (Year 4) – soil mitigation, project close-out

The LBP remediation program addresses the health and safety risks of LBP on transmission towers. It will also provide these target structures with a protective coating that will enhance their corrosion resistance.

Because the tower corrosion and lead-based paint remediation programs are new endeavors for SCE, historical costs are not available for forecasting purposes. SCE's forecasting is based on unit costs and known scope, both for inspections and for remediation. The cost to remediate known towers with some level of corrosion, plus the cost to inspect the rest of the towers for existing corrosion makes up proposed funding levels for the 2019-2020 period.

The estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are $22.300 million.

3. 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. 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 or no longer available, or that can no longer be cost-effectively maintained. The replacement of bulk power circuit breakers is under FERC jurisdiction and is necessary to proactively replace aging 220 kV and 500 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. The estimated ISO-related capital expenditures for this program that are projected to go into rate base in the period January 2019 through December 2020 are $5.934 million.

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

Substation Miscellaneous Equipment Additions & Betterment captures the cost to remove, replace, and retire miscellaneous assets on a reactive or programmatic basis. It does not include the costs for preemptive replacement of circuit breakers, substation transformers, substation protection, and control systems. Instead, it is predominantly like-for-like replacement of miscellaneous substation equipment with limited engineering. 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. Example includes the replacement of obsolete Disconnect Switches at Devers and Mira Loma 500 kV Substations. The estimated ISO-related direct capital expenditures for this program that are projected to go into rate base in the period January 2019 through December 2020 are $41.551 million.

5. **Bulk Power 500 kV & 220 kV Line Relay Replacement (PIN: 5089)**
   Relays are devices that monitor the currents and voltages for each piece of equipment in substations and actuate circuit breakers should these parameters exceed acceptable limits. Relays in 500 kV and 220 kV substations fall under FERC jurisdiction. Examples include the replacement of bulk relay(s) at Lugo, Mira Loma, Eldorado 500 kV, and Alamitos, Santiago, Kramer 220 kV substations. The estimated ISO-related direct capital expenditures for this program that are projected to go into rate base in the period January 2019 through December 2020 are $14.331 million.

6. **Substation Transformer Bank Replacement Program (PIN: 5210)**
   AA-Bank transformers are located in major substations where they take electricity at the 500 kV transmission level and transform it down to 220 kV. The Substation Infrastructure Replacement ("SIR") program identifies and replaces AA-Bank transformers that are approaching the end of their service lives, that contain parts which are known to be seriously problematic or are no longer available, or that can no longer be cost effectively maintained. The costs of AA-Bank transformer replacement are all under FERC jurisdiction.

A-Bank transformers are located in major substations where they take electricity at the 220 kV transmission level and transform it down to a subtransmission voltage, either 115 kV or 66 kV. The SIR program identifies and replaces A-Bank transformers those are approaching the end of their service lives, that contain parts which are known to be seriously problematic or are no longer available, or that can no longer be cost-effectively maintained. The consequences of an in-service failure of an A-Bank transformer are highly undesirable. A-Bank transformers typically supply power to large portions of SCE's distribution system servicing hundreds of thousands of customers. While redundancy is built into the A-Bank system, an in-service failure would place the system into an "N-1" condition, wherein a second failure or system disturbance could result in a massive blackout affecting significantly large areas. The consequences of such a blackout are so severe that SCE believes that every reasonable precaution must be taken to prevent it. Although infrequent, in-service failures of A-Bank transformers can be violent. These transformers are oil-filled and catastrophic failures and ensuing fires can endanger the safety of SCE employees and the operability of nearby equipment. Inspections are extremely helpful in identifying many incipient failures. However, because of the speed at which failure mechanisms can arise and progress, inspections cannot prevent all failures. Therefore, planned preemptive replacements under controlled conditions of transformers clearly approaching the end of their service lives are a prudent and responsible action to minimize the risk of in-service failures.

In summary, the replacement of AA- and A-Bank transformers is managed by the Substation Infrastructure Replacement program which combines engineering analysis and expert judgment to ensure that the appropriate number of AA- and A-Bank transformers is replaced each year and that those which are replaced are the most risk-significant.

The estimated ISO-related direct capital expenditures for this program that are projected to go into rate base in the period January 2019 through December 2020 are $25.791 million.

7. Transmission Line Rating Remediation (PINs: 7298)

SCE has been conducting a Transmission Line Rating Study to identify transmission lines potentially in violation of CPUC GO 95. As part of the study, SCE has completed its initial survey of all of SCE's CAISO-controlled transmission lines built before 2005. Based on the results of the survey, SCE prioritized the transmission line discrepancies that will require line clearance remediation. A discrepancy is any condition found in the field requiring remediation to meet GO 95 requirements during peak loading conditions. Discrepancies have been prioritized based on criteria such as line sag when operating at or below 130 degrees Fahrenheit, and potential risk to public safety and system reliability based on location of span, terrain, encroachment type, and extent of deviation from standards. The study prioritized the discrepancies within a span into six levels, with A1 being the highest priority, and followed by A2, A3, B1, B2, and B3. Remediation work to address discrepancies includes replacing towers and poles, clearing brush, replacing insulators, removing slack from lines, and other efforts to remediate line clearance issues.

In 2015, SCE finalized work on a plan to remediate all CAISO discrepancies over a ten-year period, 2016 – 2025. This plan requires a significant increase in work and spend over the ten-year period. Through 2015, remediation efforts have focused on the higher priority discrepancies. This remediated 428 discrepancies, cleared 866 discrepancies, and identified 344 discrepancies cleared by other SCE programs or projects. As of the end of 2015, there are approximately 6,167 CAISO discrepancies to be remediated within the ten-year period. To accomplish this increased level of work, SCE plans to take a more programmatic approach to the remediation work, including the utilization of CPUC licensing projects, major projects exempt from licensing (i.e., re-conductors), and minor projects exempt from licensing (individual tower/pole modifications or replacements). The ten-year plan was developed with North American Electricity Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") input.

Besides the CAISO discrepancies, NERC/WECC requested that SCE perform studies on the non-CAISO controlled lines (radial lines). This study was completed in 2015 and will require additional discrepancies to be remediated by 2030, as agreed to by SCE and NERC/WECC.

Transmission Line Rating Remediation ("TLRR") efforts include both O&M and capital work. A high percentage of these expenditures are for work on CAISO-controlled transmission, which is under FERC jurisdiction.

TLRR capital expenditures are based on a specific, project-based forecast. The forecast includes the costs for remediation activities, engineering, environmental, and materials, allocated by year and by priority level. A large increase in 2017 and 2018 spending was driven by major construction projects coming out of design, leading to large scale material procurement and a high volume of bulk power construction. Most projects and associated costs are FERC jurisdictional.

The significant increase in spend is correlated with the change in program strategy to meet the regulatory requirements discussed above. Using the previous strategy, it would have taken SCE well beyond the agreed upon ten-year timeframe to remediate all discrepancies. To shorten the time to achieve compliance, SCE developed a plan that focuses more on bundling many discrepancies by circuit and geographic location, such as utilizing major licensed re-conductor projects which can remediate many discrepancies in the scope of one large project. Since licensing projects take longer to complete, the costs requested in this rate case are for many smaller scale projects that do not require licensing, though the same bundling approach applies. This will allow SCE to complete the remediation to meet the regulatory requirements. Forecasts for projects in the preliminary stages of engineering use a cost per remediation method and projects with completed engineering use cost estimates for specific scope.

Total forecast of TLRR direct capital expenditures between 2019 and 2020 is $202.136 million and estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are $168.937 million.

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

Operating in one of the most seismically active areas in the United States, a major earthquake is one of the most catastrophic incident SCE can plan for; therefore, it is the basis for the company's All Hazard Assessment and Mitigation Program and associated exercises. In a 2015 report, the United States Geological Survey (USGS) introduced its latest earthquake model, the third Uniform California Earthquake Rupture Forecast (UCERF3). The UCERF3 model shows a prediction rate for earthquakes in Southern California with magnitudes between 5.0 and 8.0 greater than that in prior published earthquake models. According to the USGS report, the increased threat is due to the many interconnected faults in California. These interconnected faults can trigger seismic activities in one another, increasing the probability of multi-fault ruptures. This probability is significant due to the number of faults interconnected with San Andreas, the fault most likely to be the source of the most catastrophic earthquakes in the state. The report also reveals that the number of known faults in California is 250,000, not 10,000 as previously reported, and more faults will probably be discovered. The report supports recent predictions there is a 60 percent chance Southern California will experience a magnitude 6.7 earthquake in the next 30 years and a 46 percent chance a 7.0 will occur. These predictions are driving SCE's focus on preparing for and mitigating the potential impacts of moderate to large-scale earthquakes.

SCE prioritized bulk transmission substation assessment from 2016-2020. Transmission substations are large and can support hundreds of thousands of customers by moving power from high voltage transmission lines to lower voltage distribution systems. Assessment of transmission substations identified improvements that could be made that would limit the likelihood of a major earthquake significantly damaging the substations assets so as to prevent it from being able to deliver power to other transmission substations or to lower voltage distribution substations. The scope of this effort included assessment of all 70 of SCE's transmission substations and mitigation activities to the majority of these locations. This work is still under way with a large majority of these mitigations scheduled to be completed by 2020. Between 2021-23 SCE plans to complete three additional transmission substation mitigations. Most of this mitigation activity includes replacing older fragile transformer bushings, securing curing hanging and suspended equipment at the end of transmission lines and insuring there sufficient conductor slack to prevent it from snapping during an earthquake. These remediation activities were results from a third party consultant's assessment report and field reconnaissance by SCE. The recommendations were based on improving lower cost components that if improved, significantly avoids the likelihood of an outage.

To continue to improve the survivability of transmission substations, additional analysis indicates that retrofitting the buildings that houses electrical and computer systems that support the delivery or power from the substation would improve the likelihood that the substation could continue to deliver services to lower voltage substations that ultimately serve power to customers. In this next phase of work SCE will perform building retrofits in some transmission substations to insure buildings stay intact and are able to support critical power delivery functionality to distribution substations. SCE plans to retrofit 10 of transmission substation buildings between 2021 and 2023.

Transmission substations are connect by transmission lines. Transmission lines, specifically transmission towers are susceptible to damage. Damage is typically not with the structure itself as various design standards make it such that the structure will not snap in half, rather the vulnerability is typically with the ground moving such as in a landslide, significantly causing the tower to move. SCE has already has assessed through desktop analysis most of its transmission towers and has conducted site investigation along two specific corridors, along the Cajon and Tajon pass. We have identified mitigation that helps prevent the ground beneath a transmission tower for moving significantly during an earthquake. By 2020 we expect to mitigate 8 towers that have been identified as vulnerable to landslide risk or earth movement that may cause damage that will prevent it from supplying power from one transmission substation to another. From 2021 to 2023 we anticipate to identify and mitigate additional transmission towers.

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 $9.788 million to perform corresponding mitigations for SCE's transmission assets in the period January 2019 through December 2020. All of the amount is projected to go into rate base during this period.

9. Physical Security Systems – Electric Facilities (PIN: 7454)

The physical security systems program for electric facilities 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 Physical Security Systems – Electrical Facilities 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 2019 through December 2020 are $11.153 million.

10. 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 2019 through December 2020 are $10.777 million.

11. LADWP DC electrode replacement (Land and Ocean segments) (PIN: 3138)

The purpose of this project is to improve the availability and reliability of the newly upgraded Sylmar Converter Station East, the ground return cables need to be replaced and encased in a separate conduit bank along a new circuit route to the ocean electrodes. The project scope includes replacing the existing underground cables with higher-rated, insulated cables that eliminates oil pressure build-up and rupturing of the external lead sheath. The existing cables carry ground return current to ocean electrodes for the Sylmar High Voltage Direct Current ("HVDC") transmission system and they were installed in 1969 when the Pacific DC Intertie ("PDCI") was originally energized at +/- 400 kV, 1800 Amps, and 1440 MW.

After several upgrades to the PDCI, there have been no upgrades to the electrode and numerous failures have been sustained. Current operations are at a higher rating of +/- 500 kV, 3100 Amps, and 3100 MW. To replace the underground portion of the PDCI ground return system, project scope includes 7-8 miles of underground line from Kenter Terminal Tower and installation of up to 8 new miles of concrete encased conduit bank and 120,000 feet of new cable.

The proposed operating date is December 2019 with estimated ISO-related direct capital expenditures of $32.441 million, which represents SCE's 50% share of the project. All of the total project cost is projected to go into rate base during this period.

12. 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 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 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 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 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 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;
- 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 $89.637 million, which represents SCE's 50% share of the project. All of the total project cost is projected to go into rate base during this period.

13. West of Devers (PIN: 6420)

The West of Devers Project 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 in support of California's renewable portfolio standards goals.

In August 2016, the CPUC approved the construction of the West of Devers Project. As a result of the delay in receipt of the Project's approval from the CPUC, SCE deferred the forecasted timing of project capital expenditures. ORA filed an Application for Rehearing in September 2016 stating that the August 2016 decision failed to follow the California Environmental Quality Act when it approved the Project 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 Project.

The proposed operating date for project is May 2021 with estimated ISO-related direct capital expenditures of $26.594 million projected to go into rate base in the period January 2019 through December 2020.

14. 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 July 2019 with estimated ISO-related direct capital expenditures of $5.406 million. All of the amount is projected to go into rate base during this period.

15. La Fresa Substation New MEER (PIN: 6824)

This project involves the installation of a new Mechanical Electrical Equipment Room (“MEER”) building in addition to the current MEER building, and cutting over the existing protection. The new MEER is the second phase of a prior addition of a 220/66 kV transformer bank and new 220 kV circuit breakers at La Fresa. The new MEER building is necessary to address the aged control building, house the existing substation controls and protection, as well as to accommodate current standard SCE substation automation. The proposed operating date is November 2019 with estimated ISO-related direct capital expenditures of $11.136 million. All of the amount is projected to go into rate base during this period.

16. Chino 220 kV Circuit Breakers (PIN: 7120)

Currently the No. 1A bank at Chino 230/66 kV Substation is connected in bank-on-bus configuration. Equipping the bank in circuit breakers configuration would ensure compliance with current planning criteria and guidelines which would offer higher operation flexibility. Project scope also includes installation of new 220/66 kV and 12kV MEER (including relays). The proposed operating date for the specific project is December 2020 and total ISO related direct capital expenditures that are projected to go into rate base during this period are $25.998 million.

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

This project is need to interconnect the Casa Diablo IV Project to SCE's Casa Diablo Substation. The scope of the project includes the Casa Diablo IV interconnection in the Bishop 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 115/66 kV Substation as part of project scope. The proposed operating date for the specific project is August 2020 and total ISO related direct capital expenditures that are projected to go into rate base during this period are $5.507 million.

18. Springville 220/66 (S) - Install high-side CBs to correct criteria violation (PIN: 7518)

Project is needed in order to comply with the Line & Bus criteria that all "A" banks must be connected to a Double Breaker or a Breaker-and-a-half position, (2) 230 kV CBs will be installed at Springville Substation. Scope of project includes redesign of high side feed from bank on bus to double circuit breakers at 220 kV position 4 equipped with two new 3000A 220 kV circuit breakers and disconnects at Springville Substation. L90 relays on the Springville-Magunden 220 kV transmission line will be also replaced at Magunden Substation. Proposed operating date is August 2019 with estimated ISO-related direct capital expenditures of $7.539 million projected to go into rate base between 2019 and 2020.

19. 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 so as 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 (6) 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 approx. 8 miles south of Eldorado Substation on the Eldorado-Mohave and Eldorado-Moenkopi 500 kV lines. The proposed operating date for the project is June 2018 and total ISO related direct capital expenditures that are projected to go into rate base during this period are $11.491 million.

20. Mesa Substation (PIN: 7555)

The Mesa Substation Project consists of replacing the existing 220 kV Mesa Substation with a new 500/220 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 due to schedule delays and scope changes. The remainder (500 kV portion of substation construction) was put out for bid in March 2019.

The projected operating date for the project is March 2022 with estimated ISO-related direct capital expenditures of $54.658 million in projected closing to plant in-service in the period January 2019 through December 2020.

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

Project objective is to install Centralized Remedial Action Scheme (CRAS) at Colorado River Substation for monitoring No.2AA 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 project will be in parallel with the standalone Colorado River RAS project, but won’t cut over till Q4 2015. The proposed operating date is May 2019 and estimated ISO-related direct capital expenditures that are projected to go into rate base are during this period $5.862 million.

22. Lugo-Victorville 500 kV T/L Special Protection Scheme (“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 October 2019 and estimated ISO-related direct capital expenditures that are projected to go into rate base are during this period $11.914 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.

SCE forecasts $50.634 million to complete the installations of physical security systems at NERC CIP-014 facilities.

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 Substation Physical Security Enhancements capital expenditures projected to go into rate base between 2019 and 2020 is $50.634 million and estimated ISO-related portion is $48.234 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 MEER. Proposed operation date is November 2019 with estimated ISO-related direct capital expenditures of $25.122 million projected to go into rate base between 2019 and 2020.

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 located 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 500/220/66/12 kV, Mesa 220/66/12 kV, Pardee 220 kV, Devers 500/220/115 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 work flow 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 work flow 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 $10.505 million for Rector 220/66 kV substations whose capital spend is projected to go into rate base by 2020. Capital spend on the remaining Mesa 220/66/12 kV Substation is projected to go into rate base beyond 2020, so it is excluded in this request. The proposed operating date is June 2019 and $5.612 million out of the total spend amount is ISO related.

26. Northern Area CRAS to Tehachapi RAS (PIN: 8009)

The scope of this project is to implement the Northern Area Remedial Action Scheme (RAS) analytic in Centralized RAS (CRAS). The Northern Area CRAS is a generation tripping scheme to that is needed protect against 500 kV transmission line overloads due to the high concentration of renewable generation interconnections at Antelope, Whirlwind, and Windhub Substations, under various N-1 and N-2 500 kV transmission line contingency outages. Project scope includes installation of four GE N60 relays at Whirlwind Substation to monitor the status of the Antelope-Whirlwind and Vincent-Whirlwind 500 kV transmission lines. Projected operating date is November 2019 with estimated ISO-related direct capital expenditures of $6.044 million projected to go into rate base in the period January 2019 and December 2020.

27. Substation Physical Security Enhancements (Tiers 2-4) (PIN: 8042)

Electrical power to our customers is provided through a complex network of wires leading to and from substations. Substations transform voltage from high to low, or the reverse, or perform any of several other important functions at different voltage levels. There are three general substation categories: (1) AA-Bank, or 500kV substations, (2) A-Bank, or 220kV substations, and (3) B-Bank, which are referred to as distribution substations. Each substation in these three categories has security features such as perimeter barriers, access controls using keys or electronic card readers, and alarm systems wired to the interior substation control rooms. These security measures provide our substations with a basic level of protection against intruders. Furthermore, substations and control centers may get additional security measures based on the criticality of need and the potential impact of a security breach. Criticality is defined by assessing the amount of load served, the number of network connection points, and other factors for each substation. These factors are then used to tranche the substations into a priority tier: Tier 1 accounts for the most critical electrical facilities; Tier 4 is the least critical.

Besides the Tier 1-NERC CIP 014 substations and facilities described above, SCE also plans to deploy security enhancements to other critical substations under business resiliency planning to protect our assets that are critical to safe and reliable power delivery . These critical substations are categorized into Tiers 2 to 4 based on their impact on the electrical systems if a breach or physical attack occurs. The substation tiers are prioritized based on the number of network connections, voltage class, and load. For example, Tier 2 is for 500 kV substation with five or more network connections or load over 1,000 MW or generation over 1,200 MW.

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 identifies security deficiencies at these prioritized sites and develops and implements corrective plans accordingly. The scope varies based on site factors, but the general goal of the program is to develop a standardized deployment to improve SCE's facility security maintenance and management.

SCE plans to implement eight substation projects between 2019 and 2020 to enhance fencing, gate, and lighting under the Copper Theft Mitigation program. These costs are determined by the number of feet of new fencing and the lighting needed to deter further copper theft. For Tiered Substation Physical Security programs, SCE will focus on completing the pre-CIP-014 pilot site enhancements in 2016. In 2017, SCE will complete the majority of Tier 1 (CIP-14) site enhancements, with completion of all remaining work in 2018. Beginning 2019, SCE will complete enhancements for Tier 2-4 sites. SCE used historical average costs from substation projects containing similar scope items as well as pilot site vendor quotes to develop the Tiered program forecast, inconsideration of each site's specific requirements. Total direct expenditures of $18.617 million capture these program's costs in the Transmission Substation portion of the Tier Program between 2019 and 2020. $17.908 million is the ISO related amount which is projected to go into rate based between 2019 and 2020.

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 of these 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 also installation of a new 100 MVAR shut line reactor and appurtenant equipment at Eldorado Substation. The proposed operational year for the Project is May 1, 2020, as required by the CAISO. An estimated ISO-related direct capital expenditures of $14.967 million is projected to go into rate base in the period January 2019 through December 2020.

29. Bob Switch to Eldorado 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 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 proposed operating date is July 2019 and estimated ISO-related direct capital expenditures that are projected to go into rate base during this period are $7.985 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 December 2020 with estimated ISO-related direct capital expenditures of $26.558 million in projected closing to plant in-service in the period January 2019 through December 2020.

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.”