As illustrated in work papers to Schedule 10 and 16, during the period January 2017 through December 2018, SCE forecasts:

- $630 million in ISO-related non-incentive network transmission expenditures (Including $396 million in ISO Blanket expenditures);
- $312 million in ISO-related incentive network transmission expenditures, and;
- $367 million of FERC direct capital expenditures projected to go into rate base during the upcoming Rate Year (in the period January 2018 through December 2018).

In addition to the numerous but relatively small transmission projects, there are fourteen (14) significant transmission projects (each $5 million or greater in ISO-related costs) that are projected to go into rate base during the upcoming Rate Year – eight Blanket Specifics (items 1 through 8 below) and six specific type non-incentive projects (items 9 through 14). Table 1 below provides a summary of forecast FERC-jurisdictional direct capital expenditures for fourteen (14) significant transmission projects that are projected to go into rate base in the period January 2018 through December 2018.

Table 1
FERC Direct Capital Expenditures Projected to Go into Rate Base during Rate Year[1]
($millions)

No.	PIN	Project	FERC CWIP	FERC Non-CWIP	Total
1	3364	Transmission Maintenance Planned	0	8.304	8.304
2	4211	Bulk Power Circuit Breaker Replacement	0	6.021	6.021
3	4756	Station Equipment Additions & Betterment	0	11.253	11.253
4	5089	Bulk Power 500kV & 220kV Line Relay Replacement	0	17.248	17.248
5	5210	Substation Transformer Bank Replacement Program (AA- & A-Bank)	0	16.325	16.325
6	6428	Generation Interconnection Remedial Action Scheme (RAS)	0	12.658	12.658
7	7298	Transmission Line Rating Remediation	0	127.530	127.530
8	7392	Seismic Mitigations for Transmission Substation Assets	0	13.117	13.117
9	3138	LADWP DC electrode replacement	0	5.000	5.000
10	7119	Walnut 220/66kV Bank on Circuit Breakers	0	12.613	12.613
11	7547	Eldorado-Mohave and Eldorado-Moenkopi 500 kV Line Position Swap	0	18.745	18.745
12	7763	Lugo-Victorville 500kV T/L SPS	0	13.363	13.363
13	7120	Chino 220/66 kV Bank on Circuit Breakers	0	28.932	28.932
14	7820	Substation Physical Security Enhancements	0	51.475	51.475
15	Various	Less than $5m each	0	24.541	24.541
		Total	**0**	**367.125**	**367.125**

[1] For calculation, see: "WP-Schedule 16-Summary of ISO Capital Expenditures - Non-Incentive Projects" for the PINs listed in Table 1.

1. Transmission Maintenance Planned (PIN: 3364)

Transmission Capital Maintenance includes the costs to remove, replace, and retire assets on a programmatic or reactive basis.

Planned transmission capital maintenance is driven by inspection results or Infrastructure Replacement Program activities. Sometimes, field observations lead to projects to address emergent issues in a particular grid or equipment or structure type. In other instances, projects are identified through SCE's Transmission Infrastructure Replacement program, which programmatically identifies capital maintenance work for items such as conductor and switch replacements using grid and/or engineering analyses. SCE initiated its Transmission Infrastructure Replacement program in 2013 to address issues that were identified but had not yet led to equipment failure. These issues result from aging transmission infrastructure and address safety and/or reliability risk. The criteria for projects identified in this program varies, but includes the replacement of obsolete or deteriorated assets.

Reactive replacements are initiated when equipment fails in-service, equipment failure is imminent, or possible safety issues are identified. Equipment identified as requiring replacement must be replaced in a timely manner because transmission equipment failures may lead to prolonged outages, unsafe operating conditions, or a more expensive reactive solution.

Depending on the maintenance work, the costs either record to O&M or capital. For example, insulator replacements are treated as O&M expenses and conductor or tower replacements are treated as capital expenditures.

The 2017-2018 forecast for Transmission Capital Maintenance includes planned capital maintenance driven by inspection results or identified through the Transmission Infrastructure Replacement program. Planned capital maintenance includes the replacement of obsolete equipment (which prevents operational issues), projects that increase public safety (using steel poles, where possible, for conductor that spans a freeway), the installation of fencing around rights-of-way, and projects for GO 95 or GO 128 compliance. The estimated ISO-related direct capital expenditures for this program that are expected to be operational in the period January through December 2018 are $8.304 million.

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

Bulk power circuit breakers interrupt the flow of electricity through a transmission lines, typically at the 500kV or 220kV 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 expected to be operational in the period are $6.021 million.

3. **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 digital fault recorders (DFRs) at Mira Loma, Antelope, Colorado River, Devers, Eldorado, and Rancho Vista 500kV Substations. The estimated ISO-related direct capital expenditures for this program that are expected to be operational in the period are $11.253 million.

4. **Bulk Power 500kV & 220kV 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, Vincent, Eldorado 500kV, and Vista, Ellis, Hinson 220kV substations. The estimated ISO-related direct capital expenditures for this program that are expected to be operational in the period January through December 2018 are $17.248 million.

5. **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. So severe are the consequences of such a blackout 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 expected to be operational in the period January through December 2018 are $16.325 million.

6. Generation Interconnection Remedial Action Scheme (PIN: 6428)

SCE is implementing a comprehensive Centralized Remedial Action Scheme (CRAS) to replace the existing localized RAS and accommodate any additional RAS in the future in a phased approach. The Scope of Phase 1 is the deployment of the full capability of the CRAS Central Controller System (CCS) at the Grid Control Center (GCC) and Alternate Grid Control Center (AGCC), and the conversion and cutover of existing RAS. The estimated ISO-related direct capital expenditures for this program that are expected to be operational in the period January through December 2018 are $12.658 million.

7. Transmission Line Rating Remediation (PIN: 7298)

SCE has been conducting a Transmission Line Rating Study to identify transmission lines potentially in violation of California Public Utilities Commission (CPUC) General Order (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, followed by A2, A3, B1, B2, and B3.22 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.

The forecast of TLRR capital expenditures is based on a specific, project-based forecast. The forecast includes the costs for remediation activities, engineering and design work, and materials, allocated by year and by priority level. 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 remediations 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 2017 and 2018 is $256.418 million and estimated ISO-related direct capital expenditures that are projected to go into rate base during Rate Year are $127.530 million.

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

SCE plans to retrofit and harden components in transmission substation structures built to older standards (pre-1992) and specifications that could lead to a loss of equipment functionality. Capital cost forecast is based on high level unit cost estimates provided by third party consultants and internal estimates based on similar work. SCE anticipates a steady pace of mitigation work from 2018-2020 with costs relatively stable over each year. The work includes: (1) adjusting slack between interconnected equipment, (2) retrofitting anchorage and bracing for electrical equipment, and (3) replacing older equipment or components to comply with current seismic standards. Based on the scope and costs to mitigate 10 inspected transmission substations, SCE forecasts ISO-related capital expenditures of $13.117 million to perform corresponding mitigations for SCE's transmission substations in the period January through December 2018.

9. **LADWP DC electrode replacement (Ocean segment) (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 November 2017 with estimated ISO-related direct capital expenditures of $41.612 million, which represents SCE's 50% share of the project. Approximately $5 million out of the total project cost is projected to go into rate base during Rate Year.

10. **Walnut 220/66kV Bank on Circuit Breakers (PIN: 7119)**

Currently No. 3A and 4A banks at Walnut 230/66 kV Substation are connected in bank-on-bus configuration. Equipping the banks in circuit breakers configuration would ensure compliance with current planning criteria and guidelines which would offer higher operation flexibility. The proposed operating date is December 2018 with estimated ISO-related direct capital expenditures of $12.613 million.

11. 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 is January 2018 with estimated ISO-related direct capital expenditures of $18.745 million.

12. Lugo-Victorville 500kV T/L SPS (PIN: 7763)

This Special Protection Scheme (SPS) is required to reliably interconnect and integrate the Transition Cluster (TC) generation projects. To prevent overloads on the jointly-owned Lugo-Victorville 500 kV T/L, this SPS trips the TC 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. The proposed operating date for the specific project is December 2018, with total ISO related direct capital expenditures of $13.363 million that is projected to go into rate base during Rate Year.

13. Chino 220/66 kV Bank on 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. The proposed operating date for the specific project is June 2018, with total ISO related direct capital expenditures of $28.932 million.

14. Substation Physical Security Enhancements (PINs: 7820)

In 2013, a PG&E substation was attacked, resulting in substantial reduction in transmission capability and over $15 million in damages. This was the first significant attack on a substation in the United States. 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. This program was identified as Tier 1-NERC CIP-014. CIP-014 requires utilities to assess, review, and identify critical facilities that are vulnerable to physical attack risks, and furthermore, develop and implement a plan to enhance protection for these assets.

After the 2013 attack at the PG&E's Metcalf transmission substation, SCE evaluated its substations to identify areas where the company should bolster its security to prevent a similar occurrence on SCE assets. Because of this, and prior to the development of the NERC CIP-014 program, SCE identified seven substations in 2014 for physical security enhancements. These substations were critical to the reliable operation of our grid. In addition, SCE considered these substations to be probable candidates for future NERC CIP-014 requirements due to their criticality. Therefore, SCE initiated pilot physical security enhancements to four out of the seven substations in 2014, in anticipation of the release of CIP-014. These enhancements included improvements to walls, reinforcement of gates, concealment of key assets, and improvements to technical security to detect threats and improve response, including improved cameras, alarms, and lighting.

CIP-014 does not define the specific mitigation tools and methods for identified critical facilities but requires utilities to develop and implement a security risk mitigation plan. To prepare and help inform the development of our security mitigation plan, this pre-CIP-014 pilot program was created not only for SCE to get ahead of the anticipated compliance requirements but also to pilot and test security technology options to determine the best practices to be later incorporated into the remaining CIP-014 qualified sites. Examples of piloting scope include testing long range video or gunshot detection technology to increase situational awareness, building high-security physical perimeter walls, improving security lighting and audible alarms to deter attacks. In 2015, CIP-014 was released, and the final version of the regulation included criteria that two of the four pilot sites met. Together with the remaining three CIP-014 qualified sites, SCE has seven substations that require physical security enhancements under Tier 1 Physical Security Program.

Both prior recorded and forecast between 2017 and 2018 of Substation Physical Security Enhancements Project direct capital expenditures capture these programs' expenditures in the Transmission Substation portion of the projects. These expenditures are required to fund physical security enhancements such as: AC/DC power feeds to security equipment and lighting, providing ballistic barriers around critical equipment, installing concealment, and replacing or modifying substation fences and gates.

SCE will focus on completing the majority of Tier 1 (CIP-14) site enhancements by 2018, with completion of all remaining work in the following year. The proposed operating date for the specific project is December 2018, with total ISO related direct capital expenditures of $51.475 million.

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