**Transmission Project Review (TPR) Process**

**CPUC Energy Division Staff Comments on Southern California Edison (SCE) December 2025 TPR Process Data**

As part of the TPR Process approved by the California Public Utilities Commission (CPUC) in Resolution E-5252,[1] Energy Division Staff of the CPUC (CPUC Staff) provide these comments to SCE on its December 2025 TPR Process Review Period.

## Introduction

On December 1, 2025, SCE provided Stakeholders in the TPR with the Project Spreadsheet (PS) of transmission projects and programs under the TPR Process. The PS and accompanying materials are intended to provide the CPUC and Stakeholders with current, specific, and system-wide transmission capital data on a semi-annual basis.

The December 2025 PS presents capital expenditures for the 2021-2030 period, a change from the June 2025 TPR, with 2020 being eliminated and 2030 being added for the first time. It reflects a continued expansion of the transmission project portfolio relative to the June 2025 cycle, both in terms of total project count and aggregate cost. The December submission includes 508 projects and programs, compared to 484 in the June 2025 PS, representing a net increase of 24 projects. Total current projected total and actual final costs increased from approximately $9.71 billion to $10.55 billion, an increase of approximately $840.7 million (8.7 percent).[2]

For the historical period, capital expenditures in the overlapping years between the June 2025 PS and the December 2025 PS (*i.e.*, 2021 to 2025) decreased by approximately $94 million, declining from $2.03 billion in the June 2025 TPR PS to $1.94 billion in the December 2025 TPR PS.[3]

For the forecast period, capital expenditures in the overlapping years between the June 2025 TPR PS and the December 2025 TPR PS (*i.e.*, 2026 to 2029) decreased by approximately $96 million, declining from $3.48 billion in the June 2025 TPR PS to $3.38 billion in the December 2025 TPR PS.[4]

These shifts contrast with the prior cycle's observations that overall portfolio costs were relatively flat and that the largest projects exhibited little to no movement during the June review period. Roughly $615 million of the cost growth shown in the December submittal is attributable to increases within existing projects. Several of these increases are significant: 8 projects alone account for $410 million in added costs, including the Riverside Transmission Reliability Project, which rose 19 percent after years of little movement, and specific Transmission Line

[1] CPUC Resolution E-5252, page 3.
[2] SCE TPR Process Project Spreadsheet June 2025 and SCE TPR Process Project Spreadsheet December 2025
[3] *Ibid*.
[4] SCE TPR Process Project Spreadsheet June 2025 and SCE TPR Process Project Spreadsheet December 2025.

Rating Remediation (TLRR) and 230kV-related upgrades that show double-digit or higher increases.[5]

Unlike the June 2025 cycle, where changes were driven primarily by portfolio adjustments (including removal of projects), the December 2025 cycle reflects growth within an otherwise stable project set, as no projects were reported as offboarded. This shift indicates that cost changes are increasingly attributable to project development and execution factors rather than changes in portfolio composition.

In addition to the PS, SCE provided 153 additional authorization documents related to specific projects. These documents include presentation decks and meeting minutes for projects that were approved during meetings, as well as work initiation forms and project summaries.[6]

During this TPR Review Period, CPUC Staff requested, and SCE provided detailed information on several individual projects and programs, including SP-01 Calcite, SP-10 Riverside Transmission Reliability Project, SP-04 Alberhill Substation Loop-In, and TLRR work, including SP-26 Control-Silver Peak TLRR. CPUC Staff also asked questions designed to understand SCE's process in areas such as utility prioritization, cost-benefit analysis, Association for the Advancement of Cost Engineering (AACE) estimate maturity, supply chain management and advance procurement, and Allowance for Funds Used During Construction (AFUDC).

Several key insights emerge from a review of the December 2025 cycle data:

- **Cost growth is primarily internal to the portfolio**
  The majority of cost increases are driven by changes within existing projects, rather than by new project additions.
- **A small number of projects drive a large share of total cost changes**
  This concentration underscores the importance of detailed project-level review, particularly for large and complex projects.
- **Cost escalation is increasingly linked to project development realities**
  Cost increases on longstanding projects are associated with factors such as permitting, design evolution, and construction complexity.
- **External drivers continue to play a significant role**
  New projects associated with Generator Interconnection and Deliverability Allocation Process (GIDAP), California Independent System Operator (CAISO) Transmission Planning Process (TPP), and system security requirements highlight the ongoing influence of external planning and policy processes.

[2] *Ibid*.
[6] SCE TPR Process December 2025 Cover Letter.

**Summary of the December 2025 TPR Process Project Spreadsheet**

The December 2025 TPR PS shows a transition from relatively stable capital expenditures in 2021–2024 (ranging from $268 million to $484 million annually) to a clear ramp beginning in 2025 ($578 million) and continuing into the forecast period. Spending increases to roughly $860 million in 2026, remains near $900 million in 2027, goes back to approximately $800 million in 2029 and 2029, and reaches $1.07 billion in 2030. This reflects a shift from a steady level of investment to a higher, sustained level of capital spending beginning around the 2025 mark.

This growth is driven primarily by Poles and Wires and Substation investments, which dominate the portfolio across all years. In the forecast period, Poles and Wires is increasingly driven by large allocations in “Other” and Policy-related spending, while Substation growth is supported by Reliability, Load Growth, and Work Requested by Others, including a notable increase in the later years. Smaller categories such as GIDAP and Other remain more variable, with GIDAP showing uneven, project-driven spending patterns. Overall, the portfolio reflects a continued focus on core transmission and substation infrastructure, with increasing contributions from programmatic and externally driven projects in the outyears.

Table 1 below shows the actual capital expenditures by category, while Table 2 shows the projected capital expenditures by those categories for future years.

**Table 1: Actual Capital Expenditures by Year, Category, and Primary Purpose ($000)**

| | 2021 | 2022 | 2023 | 2024 | 2025 | Total |
|---|---|---|---|---|---|---|
| **Poles/Wires** | | | | | | |
| Address Results of Power Flow Analysis | 52,341 | 5,038 | 7,743 | 4,369 | 9,365 | **78,857** |
| Asset Condition | 9,882 | 4,346 | 1,699 | 5,805 | 2,943 | **24,675** |
| CAISO Transmission Planning Standards | - | - | - | - | - | **-** |
| Emergency Response | - | - | - | - | - | **-** |
| Generator Interconnection | - | - | 7 | 9 | 8 | **24** |
| Load Growth | - | - | - | - | - | **-** |
| Local Capacity Requirement | 19,242 | 1,143 | 10,200 | 26,842 | 13,978 | **71,406** |
| Other | 86,898 | 91,666 | 59,010 | 39,233 | 121,873 | **398,680** |
| Physical Security | - | - | - | - | - | **-** |
| Policy | 61,860 | 38,053 | 24,594 | 37,205 | 71,884 | **233,597** |
| Reliability | 10,361 | 11,605 | 8,360 | 5,683 | 28,021 | **64,030** |
| Safety | 9,410 | 11,913 | 6,133 | 27,082 | 26,476 | **81,014** |
| Wildfire Mitigation | - | - | - | - | - | **-** |
| Location, Environmental Conditions | - | - | - | - | - | **-** |
| Work Requested by Others | 1,954 | 347 | 226 | 616 | 733 | **3,875** |
| NERC/WECC/CAISO Compliance | - | - | - | - | - | **-** |
| **Poles/Wires Total** | **251,947** | **164,113** | **117,972** | **146,845** | **275,280** | **956,156** |
| **Substations** | | | | | | |
| Address Results of Power Flow Analysis | - | - | - | - | - | **-** |
| Asset Condition | 16,122 | 20,932 | 31,741 | 29,937 | 22,677 | **121,410** |
| CAISO Transmission Planning Standards | - | - | - | - | - | **-** |
| Emergency Response | - | - | - | - | - | **-** |
| Generator Interconnection | 293 | 325 | 184 | 629 | 3,942 | **5,373** |
| Load Growth | 1,612 | 1,457 | 928 | 3,059 | 5,890 | **12,946** |
| Local Capacity Requirement | - | - | 8 | 1,269 | 2,331 | **3,607** |
| Other | 9,378 | 8,320 | 7,438 | 5,361 | 1,975 | **32,473** |
| Physical Security | 11 | 1,237 | 3,734 | 160 | 1 | **5,143** |
| Policy | 10 | 1 | - | 96 | 3,434 | **3,541** |
| Reliability | 37,995 | 26,131 | 27,666 | 37,715 | 87,715 | **217,222** |
| Safety | 8,863 | 2,565 | 487 | 7,369 | 12,565 | **31,849** |
| Wildfire Mitigation | 635 | 1,412 | 301 | 432 | 612 | **3,392** |
| Location, Environmental Conditions | - | - | - | - | - | **-** |
| Work Requested by Others | 41,948 | 12,130 | 1,403 | 3,492 | 62,503 | **121,477** |
| NERC/WECC/CAISO Compliance | 86,023 | 49,133 | 25,054 | 11,326 | 7,702 | **179,238** |
| **Substations Total** | **202,889** | **123,646** | **98,943** | **100,845** | **211,349** | **737,672** |

| | 2021 | 2022 | 2023 | 2024 | 2025 | Total |
|---|---|---|---|---|---|---|
| **Other** | | | | | | |
| Address Results of Power Flow Analysis | - | - | - | - | - | **-** |
| Asset Condition | - | - | - | - | - | **-** |
| CAISO Transmission Planning Standards | - | - | - | - | - | **-** |
| Emergency Response | - | - | - | - | - | **-** |
| Generator Interconnection | - | - | - | - | 10 | **10** |
| Load Growth | - | - | - | - | - | **-** |
| Local Capacity Requirement | - | - | - | - | - | **-** |
| Other | 283 | 2,184 | 404 | 2,440 | - | **5,310** |
| Physical Security | 8,408 | 16,458 | 13,522 | 12,757 | 33,415 | **84,560** |
| Policy | - | - | - | - | - | **-** |
| Reliability | 5,625 | 5,887 | 5,851 | 5,029 | 35,574 | **57,966** |
| Safety | 2,862 | 2,296 | 2,121 | 4,388 | 22 | **11,688** |
| Wildfire Mitigation | - | - | - | - | - | **-** |
| Location, Environmental Conditions | 1,258 | 1,762 | 345 | 23 | - | **3,387** |
| Work Requested by Others | 10 | 15 | 12 | 71 | 233 | **340** |
| NERC/WECC/CAISO Compliance | - | - | - | - | - | **-** |
| **Other Total** | **18,446** | **28,602** | **22,254** | **24,707** | **69,253** | **163,261** |
| **GIDAP** | | | | | | |
| Address Results of Power Flow Analysis | - | - | - | - | - | **-** |
| Asset Condition | - | - | - | - | - | **-** |
| CAISO Transmission Planning Standards | - | - | - | - | - | **-** |
| Emergency Response | - | - | - | - | - | **-** |
| Generator Interconnection | (3,545) | (745) | 16,953 | 2,518 | 18,067 | **33,248** |
| Load Growth | - | - | - | - | - | **-** |
| Local Capacity Requirement | - | - | - | - | - | **-** |
| Other | - | - | - | - | - | **-** |
| Physical Security | - | - | - | - | - | **-** |
| Policy | - | - | - | - | - | **-** |
| Reliability | - | - | - | - | - | **-** |
| Safety | (3) | 1 | 1 | - | - | **(1)** |
| Wildfire Mitigation | - | - | - | - | - | **-** |
| Location, Environmental Conditions | - | - | - | - | - | **-** |
| Work Requested by Others | 14,008 | 10,650 | 11,633 | 6,611 | 3,805 | **46,707** |
| NERC/WECC/CAISO Compliance | - | - | - | - | - | **-** |
| **GIDAP Total** | **10,460** | **9,906** | **28,587** | **9,129** | **21,872** | **79,953** |
| | | | | | | |
| **Grand Total** | **483,742** | **326,266** | **267,757** | **281,525** | **577,753** | **1,937,043** |

**Table 2: Projected Capital Expenditures by Year, Category, and Primary Purpose ($000)**

| | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
|---|---|---|---|---|---|---|
| **Poles/Wires** | | | | | | |
| Address Results of Power Flow Analysis | 74,280 | 61,202 | 40,598 | - | - | **176,080** |
| Asset Condition | 3,124 | 3,164 | 3,233 | 3,254 | 3,342 | **16,118** |
| CAISO Transmission Planning Standards | - | - | - | - | - | **-** |
| Emergency Response | - | - | - | - | - | **-** |
| Generator Interconnection | 30 | 290 | 500 | 158 | - | **978** |
| Load Growth | - | - | - | - | - | **-** |
| Local Capacity Requirement | 26,768 | 53,902 | 67,312 | 3,358 | 2,747 | **154,087** |
| Other | 205,770 | 133,121 | 243,420 | 442,689 | 464,955 | **1,489,955** |
| Physical Security | - | - | - | - | - | - |
| Policy | 41,193 | 81,841 | 34,545 | 20,446 | 53,676 | **231,702** |
| Reliability | 4,435 | 2,535 | 2,574 | 1,673 | 1,136 | **12,353** |
| Safety | 5,927 | 5,782 | 5,862 | 5,908 | 6,060 | **29,538** |
| Wildfire Mitigation | - | - | - | - | - | - |
| Location, Environmental Conditions | - | - | - | - | - | - |
| Work Requested by Others | 7,108 | 53,673 | 29,728 | - | - | **90,510** |
| NERC/WECC/CAISO Compliance | - | - | - | - | - | **-** |
| **Poles/Wires Total** | **368,635** | **395,510** | **427,772** | **477,486** | **531,916** | **2,201,320** |
| **Substations** | | | | | | |
| Address Results of Power Flow Analysis | - | - | - | - | - | **-** |
| Asset Condition | 18,678 | 24,266 | 28,142 | 37,633 | 27,311 | **136,030** |
| CAISO Transmission Planning Standards | - | - | - | - | - | **-** |
| Emergency Response | - | - | - | - | - | **-** |
| Generator Interconnection | 14,283 | 49,855 | 3,938 | 25,401 | - | **93,477** |
| Load Growth | 10,789 | 73,579 | 55,213 | 13,615 | 49,667 | **202,863** |
| Local Capacity Requirement | 8,310 | 55,509 | 38,603 | 63,195 | 73,513 | **239,130** |
| Other | 7,986 | 3,409 | 1,251 | 1,633 | 681 | **14,960** |
| Physical Security | - | - | - | - | - | **-** |
| Policy | 9,600 | 5,000 | 5,600 | 5,600 | 6,900 | **32,700** |
| Reliability | 92,588 | 68,563 | 46,287 | 58,694 | 43,559 | **309,691** |
| Safety | 9,857 | 26,402 | 47,702 | 42,855 | 1,065 | **127,881** |
| Wildfire Mitigation | - | - | - | - | - | **-** |
| Location, Environmental Conditions | - | - | - | - | - | **-** |

| | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
|---|---|---|---|---|---|---|
| Work Requested by Others | 199,451 | 78,415 | 58,699 | 6,839 | 281,647 | **625,051**[7] |
| NERC/WECC/CAISO Compliance | 7,230 | 10,105 | 5,287 | - | - | **22,622** |
| **Substations Total** | **378,772** | **395,102** | **290,722** | **255,466** | **484,343** | **1,804,405** |
| **Other** | | | | | | |
| Address Results of Power Flow Analysis | - | - | - | - | - | **-** |
| Asset Condition | - | - | - | - | - | **-** |
| CAISO Transmission Planning Standards | - | - | - | - | - | **-** |
| Emergency Response | - | - | - | - | - | **-** |
| Generator Interconnection | 2,000 | 6,000 | 11,195 | 8,065 | 6,867 | **34,127** |
| Load Growth | - | - | - | - | - | **-** |
| Local Capacity Requirement | - | - | - | - | - | **-** |
| Other | - | - | - | - | - | **-** |
| Physical Security | 58,144 | 57,035 | 39,435 | 35,135 | 28,687 | **218,435** |
| Policy | - | - | - | - | - | **-** |
| Reliability | 19,570 | 22,528 | 12,176 | 10,101 | 5,694 | **70,069** |
| Safety | 1,387 | 6,935 | 6,935 | - | - | **15,258** |
| Wildfire Mitigation | - | - | - | - | - | **-** |
| Location, Environmental Conditions | - | - | - | - | - | **-** |
| Work Requested by Others | 398 | 356 | - | - | - | **755** |
| NERC/WECC/CAISO Compliance | - | - | - | - | - | **-** |
| **Other Total** | **81,499** | **92,855** | **69,741** | **53,301** | **41,248** | **338,643** |
| **GIDAP** | | | | | | |
| Address Results of Power Flow Analysis | - | - | - | - | - | **-** |
| Asset Condition | - | - | - | - | - | **-** |
| CAISO Transmission Planning Standards | - | - | - | - | - | **-** |
| Emergency Response | - | - | - | - | - | **-** |
| Generator Interconnection | 26,586 | 26,726 | 19,763 | 19,275 | 13,024 | **105,374** |
| Load Growth | - | - | - | - | - | **-** |
| Local Capacity Requirement | - | - | - | - | - | **-** |
| Other | - | - | - | - | - | **-** |
| Physical Security | - | - | - | - | - | **-** |
| Policy | - | - | - | - | - | **-** |

[7] The Riverside Transmission Reliability Project is the sole "Substation – Work Requested by Others" project that accounts for these forecast capital expenditure figures. Confirmation will be needed if this is an accurate categorization of such "Substation – Work Requested by Others" projects and if a correction is needed in the next TPR Cycle.

| | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
|---|---|---|---|---|---|---|
| Reliability | - | - | - | - | - | - |
| Safety | - | - | - | - | - | - |
| Wildfire Mitigation | - | - | - | - | - | - |
| Location, Environmental Conditions | - | - | - | - | - | - |
| Work Requested by Others | 2,997 | 544 | - | - | - | **3,541** |
| NERC/WECC/CAISO Compliance | - | - | - | - | - | - |
| **GIDAP Total** | **29,582** | **27,270** | **19,763** | **19,275** | **13,024** | **108,915** |
| | | | | | | |
| **Grand Total** | **858,489** | **910,737** | **807,998** | **805,528** | **1,070,531** | **4,453,283** |

**December 2025 Notable Changes**[8]

The December 2025 cycle differs from the June 2025 cycle in several important respects.

First, the June 2025 cycle reflected a net decrease in total projected expenditures (~$415 million, or -4.1%), largely driven by the removal of projects from the PS. In contrast, the December 2025 cycle reflects net cost growth without corresponding project removals, indicating a more stable but expanding portfolio.

Second, the June 2025 cycle raised questions regarding the relationship between projected and actual spending, including the observation that projected future expenditures significantly exceeded historical actuals. The December 2025 cycle continues to reflect elevated forward-looking investment levels, but the primary analytical focus has shifted toward understanding cost growth within existing projects, rather than reconciling historical versus forecasted spending levels.

Third, the December 2025 cycle includes what could be interpreted as a more reliable TPR dataset. With no projects removed and incremental additions more limited in number, changes in the PS increasingly reflect project-level updates, cost estimate revisions, and evolving project conditions.

Project additions in the December 2025 PS are as follows:

- 24 new projects, including:
    - Six CAISO GIDAP generation interconnection projects
        - Interconnection of five (totaling 1,250MW) battery storage (BESS) facilities at a cost of $21.2 million

[8] SCE TPR Process Project Spreadsheet June 2025 and SCE TPR Process Project Spreadsheet December 2025.

        - Interconnection of one 200MW photovoltaic (PV)/BESS hybrid facility at a cost of $3.1 million
    - Eight Substation projects
        - Two CAISO TPP-approved projects anticipated from the previous cycle
            - Serrano 500kV SCD Mitigation ($68 million)
            - Serrano 230kV GIS Bus Split ($28 million)
        - Six projects related to upgrading protection systems, site improvements, and equipment replacements
    - Two Transmission projects
        - One for adding harmonic capacitors and one for tower seismic mitigation
    - Eight Other projects, including:
        - Six physical security projects at various locations for $15 million
        - Two centralized remedial action scheme (CRAS) projects related to various locations for $13.3 million

These project additions reflect a mix of internal system needs and externally driven requirements, with a notable share tied to generation interconnection activity and CAISO-led planning processes.

This distribution underscores the continued influence of external drivers such as interconnection demand, policy-driven upgrades, and system reliability requirements on the overall transmission portfolio. At the same time, the addition of substation and protection-related projects reflects ongoing asset management and system modernization needs, consistent with patterns observed in prior cycles.

Taken together, the December 2025 PS suggests a portfolio that is both expanding and evolving, with forward-looking investment increasingly shaped by a combination of external system demands and internal infrastructure priorities.

Table 3 identifies all new projects. There were no removed projects.

**Table 3: New Projects Identified in December 2025 TPR Project Spreadsheet**

| Row/ Line No. | Project Name(s) | Category | GIDAP-Related | Project Status | Current Projected or Actual In-Service Date | Current Projected Total or Actual Final Cost ($000) |
|---|---|---|---|---|---|---|
| **PB-01.05** | Sylmar CS AC Filter Harmonic Capacitors, Converter Station | Transmission Line - Other Equipment | FALSE | Planning | 6/1/2026 | $2,598 |
| **PB-14.08** | Olinda 220/66kV - Center Satellite | Substation - Protection Relay | FALSE | Engineering less than 50% complete | 12/31/2029 | $1,076 |
| **PB-17.33** | Lighthipe Redondo | Substation - Protection Relay | FALSE | Operational | 1/10/2025 | $1,017 |
| **PB-18.15** | Inyo 220/33kV - Replace NO.1 E BANK | Substation - Transformer | FALSE | Engineering less than 50% complete | 6/13/2028 | $18,155 |
| **PB-26.07** | Lugo-Mira Loma No. 2 500kV: M10-T1 Transmission Seismic Mitigation | Transmission Line - Pole/Tower | FALSE | Planning | 9/7/2027 | $2,837 |
| **PB-29.13** | Control Substation Rebuild | Substation - Bus Arrangement | FALSE | Planning | 12/31/2032 | $33,255 |
| **PB-46.08** | (ES-5056): Physical Security | Other - Physical Security | FALSE | Engineering less than 50% complete | 12/30/2027 | $2,639 |
| **PB-46.22** | (ES-8049): Physical Security | Other - Physical Security | FALSE | Engineering less than 50% complete | 12/31/2027 | $3,733 |
| **PB-46.23** | (ES-5086): Physical Security | Other - Physical Security | FALSE | Engineering less than 50% complete | 4/21/2028 | $1,798 |
| **PB-46.24** | (ES-8055): Physical Security | Other - Physical Security | FALSE | Planning | 8/5/2027 | $2,025 |
| **PB-46.25** | (ES-5085): Physical Security | Other - Physical Security | FALSE | Planning | 3/12/2027 | $2,160 |
| **PB-46.26** | (ES-5073): Physical Security | Other - Physical Security | FALSE | Planning | 3/2/2028 | $2,684 |
| **SP-195** | ETIWANDA SUB: UPGRAD | Substation - Circuit Breaker | FALSE | Engineering more than 50% complete | 12/31/2030 | $2,367 |

| Row/ Line No. | Project Name(s) | Category | GIDAP-Related | Project Status | Current Projected or Actual In-Service Date | Current Projected Total or Actual Final Cost ($000) |
|---|---|---|---|---|---|---|
| **SP-196** | Tehachapi, Windhub, and New South of Vincent CRAS | Other - Remedial Action Scheme/Special Protection Scheme | TRUE | Permitting | 2/1/2027 | $1,356 |
| **SP-197** | TOT1108 (Q2136) - Haven Storage | Transmission Line/Substation | TRUE | Engineering less than 50% complete | 10/8/2030 | $3,082 |
| **SP-198** | TOT1100(Q2081)-Mineral King Solar | Transmission Line/Substation | TRUE | Planning | 10/8/2030 | $3,081 |
| **SP-199** | TOT1148(Q2129)-Los Nietos | Transmission Line/Substation | TRUE | Planning | 10/8/2030 | $4,257 |
| **SP-200** | TOT1062(Q2124)-Tabla Energy Storage | Transmission Line/Substation | TRUE | Planning | 10/1/2030 | $2,888 |
| **SP-201** | TOT1063(Q2125)-Tyrell Energy Storage | Transmission Line/Substation | TRUE | Planning | 3/4/2030 | $3,079 |
| **SP-202** | TOT1044/Q2059 J90 Energy Storage | Transmission Line/Substation | TRUE | Planning | 10/8/2030 | $7,845 |
| **SP-203** | Calcite CRAS - Monitoring Infrastructure | Other - Remedial Action Scheme/Special Protection Scheme | TRUE | Planning | 1/26/2027 | $12,018 |
| **SP-204** | Serrano 500kV SCD Mitigation | Substation - Multiple | FALSE | On Hold | 10/21/2033 | $68,001 |
| **SP-205** | Serrano 230kV GIS Bus Split | Substation - Multiple | FALSE | Planning | 10/21/2033 | $28,000 |
| **SP-206** | Devers Office & Shop Building | Substation - Structure | FALSE | Permitting | 3/31/2027 | $15,391 |

## Largest Projects

Large transmission projects continue to represent a significant share of total portfolio cost in the December 2025 cycle. SCE identified 15 projects with total projected costs exceeding $100 million, with a combined value of approximately $5.8 billion, or more than half of total portfolio costs. See Table 4 below. SP-157 Mesa-Del Amo-Serrano 500kV Upgrade and SP-25 Ivanpah-Control TLRR Remediation remain the largest projects in the spreadsheet, each with total estimated cost over $1 billion. These large projects have very different profiles: some are

mature construction efforts, some are still in planning; some, including SP-157 Mesa-Del-Amo Serrano and SP-165 Kramer-Victor 115kV to 230kV Rebuild 7884 are on-hold and being re-assessed in the current (2025-2026) TPP process[9]; and some are being re-costed as better information becomes available. Many of these significant projects are discussed in detail later in this report.

This concentration of investment is consistent with prior cycles and remains a key feature of the portfolio. These large projects include major transmission upgrades, substation expansions, and long-duration reliability programs and other system reinforcement efforts. Their scale and complexity make them primary drivers of both total cost and changes between reporting cycles.

The December cycle further indicates that cost growth is disproportionately concentrated within this group of large projects. A small subset of projects accounts for a substantial portion of total cost increases, with eight projects alone contributing nearly $500 million in additional costs. SP-10 Riverside Transmission Reliability Project remains a major long-delayed reliability project with 19 percent cost growth (an increase of $142 million) as new activity gets underway. SP-26 Control-Silver Peak TLRR Remediation cost estimates have moved up by approximately $73 million (22 percent). SP-24 Cerritos Channel Tower Relocation cost rose by $41 million (35 percent). SP-165 Kramer-Victor 115kV to 230kV Rebuild 7884 costs increased by $225 million (more than 300 percent).

This pattern suggests that, as projects advance, cost updates are increasingly driven by project-specific factors rather than systemic trends. For large projects in particular, these factors may include evolving engineering design and scope definition, permitting and environmental constraints, construction complexity and duration, and dependencies on external infrastructure or interconnection activity

The concentration of both total cost and cost growth within large projects underscores the importance of detailed project-level review within the TPR process. Changes to a small number of projects can materially affect overall portfolio metrics, including total cost, schedule outlook, and capital planning assumptions.

At the same time, the prominence of large, multi-year projects reflects the long-term nature of transmission investment. Many of these projects span multiple TPR cycles, and their progression over time provides insight into how cost estimates evolve as projects move from planning through design and into construction.

[9] Mesa-Del-Amo-Serrano is recommended to be canceled in the current 2025-2026 CAISO Draft Transmission Plan (page 9). Additionally, the Kramer-Victor project is subsumed into the "Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines," which is now slated for 2032, a year earlier than the 2033 ISD for the original Kramer-Victor project (page 162).

**Table 4: SCE Projects with Value over $100 Million**

| Row/ Line No | Project Name(s) | Project Status | Current Projected or Actual In-Service Date | Estimated Total Cost as of June 2025 ($000) | Estimated Total Cost as of Dec 2025 ($000) | % Change June-Dec |
|---|---|---|---|---|---|---|
| **SP-157** | Mesa - Del Amo - Serrano 500kV Upgrade | On Hold | 2034-11-08 | 1,109,736 | 1,115,592 | 1% |
| **SP-25** | Ivanpah-Control TLRR Remediation | Planning | 2031-09-26 | 1,040,679 | 1,043,899 | 0% |
| **SP-03** | West of Devers Conductor Upgrade | Operational | 2021-05-14 | 750,738 | 750,088 | 0% |
| **SP-10** | Riverside Transmission Reliability Project | Construction (under 10%) | 2029-11-15 | 588,349 | 730,307 | 19% |
| **SP-06** | Mesa Substation Expansion | Operational | 2022-05-31 | 481,820 | 481,829 | 0% |
| **SP-05** | Eldorado-Lugo-Mohave RPS Upgrade | Construction (over 75%) | 2026-06-30 | 400,586 | 400,586 | 0% |
| **SP-26** | Control-Silver Peak TLRR Remediation | Planning | 2031-03-27 | 255,831 | 328,488 | 22% |
| **SP-165** | Kramer-Victor 115kV to 230kV Rebuild 7884 | On Hold | 2033-12-31 | 72,596 | 297,408 | 310% |
| **SP-101** | Tehachapi Renewable Transmission Project (TRTP) - Segment 11 System Upgrades: New Mesa-Vincent T/L (Via Gould) 500/230kV | Operational | 2015-04-29 | 276,336 | 276,336 | 0% |
| **SP-23** | Eldorado-Pisgah-Lugo TLRR Remediation | Planning | 2030-01-31 | 238,235 | 245,736 | 3% |
| **SP-04** | Alberhill Substation Loop-In | Planning | 2029-12-31 | 242,817 | 242,857 | 0% |
| **SP-154** | New Serrano 4AA 500/230kV Bank | Engineering more than | 2033-05-24 | 212,107 | 212,107 | 0% |

| Row/ Line No | Project Name(s) | Project Status | Current Projected or Actual In-Service Date | Estimated Total Cost as of June 2025 ($000) | Estimated Total Cost as of Dec 2025 ($000) | % Change June-Dec |
|---|---|---|---|---|---|---|
| | and 230kV GIS Rebuild | 50% complete | | | | |
| **SP-09** | Sylmar Converter Station AC/DC Filter Replacement | Operational | 2020-06-10 | 127,163 | 127,286 | 0% |
| **SP-24** | Cerritos Channel Tower Relocation | Construction (under 10%) | 2028-01-31 | 76,125 | 117,739 | 35% |
| **SP-170** | Lugo-Victor 230kV Line Reconductor | On Hold | 2027-12-20 | 112,041 | 107,128 | -5% |

**Data Quality**

The data provided by SCE was generally clear and accurate. Information was provided and broken out clearly, in accordance with the requirements of Resolution E-5252. In addition, communications from the utility were timely and clear. The cover letter added clarity by summarizing all materials provided. Additionally, the PS was highlighted to show which projects were added in the December 2025 cycle.

During the March 2, 2026 Stakeholder Meeting, SCE acknowledged that many cells with line breaks were inadvertently truncated during an automated process. SCE also identified at least one field that was changed incorrectly near the end of the review process and described a need for additional review.[10] The utility was candid about the source of the problem and described several process improvements, including automated source-system pulls, trimming of immaterial spacing changes, direct use of source-system data for certain financial fields, and a final scan intended to catch spreadsheet changes that should not survive into the final submittal. Those are constructive improvements and should alleviate similar issues in future cycles.

**Data Request Responses**

During the course of the December 2025 TPR Cycle, CPUC Staff submitted four sets of data requests comprising 85 individual questions to SCE. All responses to the TPR data requests were received by April 27, 2026.

Several responses this cycle were meaningfully informative. For example, SCE broke down RTRP's roughly $142 million increase by major cost component rather than offering a generic statement about inflation or scope. SCE explained that Calcite's 23-month delay was

[10] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slide 15.

driven by County of San Bernardino environmental review and permitting actions rather than by an underlying redesign. SCE also stated directly that the Cerritos Channel Tower Relocation increase was driven by the need for a rebid process and by a longer project duration, not by a change in project scope.

At the same time, there was still a tendency in this cycle for some broad questions to require multiple rounds of inquiry before useful details emerged. That pattern is especially evident in the responses on prioritization, cost estimate maturity, and certain cost-allocation questions. Reliance on broad process descriptions without project-specific illustrations makes the PS harder to evaluate than it should be and limits the confidence that Stakeholders can place in project cost estimates.

**Stakeholder Meeting[11]**

The SCE Stakeholder Meeting, held on March 2, 2026, provided an opportunity for CPUC Staff and Stakeholders to engage directly with SCE regarding the December 2025 PS, data request responses, and ongoing transmission planning activities. Consistent with prior cycles, the meeting included both procedural topics related to the TPR Process and focused discussions on specific projects and programs.[12]

The agenda covered a broad set of recurring TPR topics and project-specific discussions on several major or high-interest projects, as well as broader topics related to generator interconnection network upgrades and CAISO TPP projects. The March 2, 2026 Stakeholder Meeting focused on several recurring themes that continue to shape SCE's project portfolio: process transparency and data quality, project execution and cost drivers, and externally driven planning factors. From a process perspective, Stakeholders continued to press for improved clarity in how information is presented in the PS, particularly around data accuracy, prioritization decisions, and the usefulness of key fields such as cost-benefit analysis and utility prioritization. SCE acknowledged prior data issues (including formatting and classification errors) and described ongoing efforts to improve validation and automation, while maintaining that certain concepts, such as enterprise-wide prioritization and cost-benefit analysis, remain inherently limited by the nature of transmission planning and regulatory requirements.

A second major area of focus was project execution and cost/schedule drivers, including supply chain constraints, advance procurement, and estimate maturity. SCE highlighted persistent long lead times for critical equipment (e.g., transformers and breakers) and described strategies such as production slot reservations to mitigate delays, while Stakeholders raised

[11] SCE TPR Stakeholder Meeting Presentation, March 2, 2026.
[12] Projects discussed were as follows: PB-05 Substation Unplanned Capital Maintenance and PB-06 Substation Planned Maintenance Program, PB-14.06 Etiwanda Substation: SA3 Hybrid Solutions, PB-18 Substation Transformer Bank Replacement Program, PB-25 Seismic Mitigation Program – Substations, SP-01 Calcite Substation, SP-04 Alberhill Substation Loop In, SP-10 Riverside Transmission Reliability Project, SP-24 Cerritos Channel Tower Relocation, SP-26 Control–Silver Peak TLRR Remediation, SP-151 New Lugo 3AA 500/230 kV Bank, SP-152 New Coolwater A 115/230kV Bank, SP-154 North of SONGS – Serrano 500kV Line Project (Competitive Project), SP-168 Vista–Etiwanda 230kV 1 Line Upgrade, SP-169 San Bernardino–Etiwanda 230kV 1 Line Upgrade.

questions about how these activities are reflected in project schedules and costs. Related discussions on AACE estimate maturity and AFUDC reinforced ongoing concerns about consistency and transparency in cost reporting. Finally, the discussion emphasized the role of external drivers, including GIDAP, CAISO TPP projects, and remedial action schemes, in shaping project scope, timing, and cost responsibility. These topics, along with focused discussion of several high-profile projects (*e.g.*, Calcite Substation, RTRP, and Cerritos Channel), underscore that a significant portion of the portfolio continues to be influenced by factors outside of SCE's direct control, contributing to variability in project development and reporting.

From a process perspective, the meeting generally reflected continued alignment with the TPR framework established under Resolution E-5252. SCE provided updates on its PS development process and confirmed that no significant methodological changes were made in this cycle. Stakeholder engagement was supported through presentation materials and follow-up data requests, with additional responses provided after the meeting to address outstanding questions.

In response to concerns identified in the June cycle, the March 2026 Stakeholder Meeting did include a chat function and individual project discussions from the appropriate subject matter experts and project managers. CPUC Staff appreciate that SCE attempted to use the meeting and follow-up discovery together as complementary tools.

On data quality, SCE acknowledged specific issues identified in the PS, including formatting challenges related to truncated fields and isolated data inconsistencies. The utility indicated that additional validation and formatting checks are planned for future cycles to improve data accuracy and usability.

Supply chain and advance procurement were discussed as part of broader project execution considerations. SCE described its coordination across internal teams to manage long-lead equipment procurement and indicated that, to date, overall demand has remained within available reserved production capacity. Stakeholder questions focused on how procurement decisions are tracked and reflected in PS fields, highlighting the importance of maintaining transparency between procurement activities and project-level schedule impacts.

The discussion of utility prioritization practices focused on how SCE documents and implements schedule changes when competing project needs arise. Data requests sought additional details on how prioritization decisions are recorded in the PS, particularly where prioritization is identified as a driver of changes to in-service dates.

SCE also addressed technical topics such as AACE class and cost estimate maturity and explained that AACE classifications reflect the estimate at the time it was developed and may not be updated until a new estimate iteration is prepared. Stakeholders sought additional clarity on how estimate maturity aligns with project phase, particularly for projects that have progressed into construction.

SCE discussed AFUDC and cost reporting practices at a high level, with attention to how carrying costs are reflected in project totals and the importance of consistent reporting across projects. Similarly, discussion of use of the cost-benefit analysis data field focused on how Field 66 is used to document project justification and the extent to which it provides meaningful insight into project value.

Project-specific discussions varied in depth. SP-10 RTRP, SP-01 Calcite, and SP-24 Cerritos Channel Tower Relocation received more detailed attention due to cost changes, schedule delays, or complexity in project drivers. Other projects, such as SP-04 Alberhill Substation Loop In and SP-168 Vista-Etiwanda 230kV 1 Line Upgrade, were addressed more briefly and were not the subject of detailed data request follow-up.

The meeting also included discussion of generator interconnection and CAISO-related projects, including both GIDAP-driven network upgrades and TPP-approved reliability and policy projects. These discussions emphasized the role of external drivers in shaping transmission project scope, timing, and cost responsibility.

Overall, the March 2026 Stakeholder Meeting provided a structured forum for reviewing the December 2025 TPR submission and addressing both process-level and project-specific topics. Compared to prior cycles, the meeting continued to reflect incremental improvements in organization and coverage of key issues, while also highlighting ongoing areas where additional clarity, particularly in documentation, cost attribution, and project-level detail, would further enhance the effectiveness of the TPR process.

**Issues of Note**

During the December 2025 TPR Review period, the CPUC Staff focused on several areas that continue to merit closer scrutiny. These issues are discussed below.

Supply Chain Constraints and Advance Procurement

Supply chain constraints and advance procurement were major topics this cycle. Through Data Request (DR) 03-01 and follow-up DR 04-04, CPUC Staff and Stakeholders asked SCE to explain how it allocates limited manufacturing slots and reserved equipment positions and how any resulting schedule or cost impacts are reflected in the PS.[13]

SCE described a coordinated approach to managing supply chain constraints and advance procurement during the December 2025 cycle, emphasizing cross-functional alignment among project development, engineering, supply chain, and operations teams. Data request responses indicate that, to date, forecasted demand has not exceeded overall reserved production capacity, and that competing needs are addressed through established internal processes that prioritize critical system and reliability requirements.[14] At the same time, Stakeholder discussions

[13] ED-SCE-TPR-Cycle 4-2025-003 Q.01 and ED-SCE-TPR-Cycle 4-2025-004 Q.04.
[14] ED-SCE-TPR-Cycle 4-2025-003 Q.01 Response.

highlighted the complexity of managing long-lead equipment and the importance of maintaining visibility into how procurement decisions translate into project schedules and Project Spreadsheet fields. Continued refinement of documentation practices in this area would further enhance transparency and provide Stakeholders with a clearer understanding of how procurement strategies support timely project delivery.[15]

Utility Prioritization Ranking and Delayed In-Service Dates

Another core issue this cycle was the meaning of "prioritization" when used as an explanation for delayed in-service dates. Through DR 03-02, CPUC Staff asked SCE to explain what minimum information is recorded when prioritization causes a schedule change, where that information is stored, and how it is translated into the spreadsheet for Stakeholder review.[16] SCE explained that "the term prioritization does not reflect an enterprise-wide ranking across projects & programs. It is intended to describe the project being delayed or advanced due to need and/or resource availability. The change is system need, resource availability, outage constraints, or other project-specific conditions that affect constructability or completion," but that "the prioritization of the project is not tracked as SCE does not have a utility-wide prioritization ranking system."[17]

A delayed in-service date can result from many materially different causes: outage constraints, internal labor shortages, changing system needs, deliberate sequencing behind a higher-risk reliability project, interactions with another project, or an originally unrealistic schedule. Simply coding a delay as "prioritization" without tracking changes or explaining these causes does not tell Stakeholders which of those circumstances occurred, whether the delay is prudent, or whether the original schedule was ever realistic in the first place.

It appears that SCE does maintain some internal documentation of prioritization-related decisions, but these details are not consistently included in the PS. That approach limits the value of the spreadsheet as a standalone transparency tool. If prioritization continues to be used as a general explanation for changed dates, SCE should use a standardized note structure (utilizing Data Field 70) that identifies the trigger, the competing constraint, and the reason the revised sequence is considered appropriate. Without that level of explanation, prioritization becomes too broad a label to be analytically useful.

Use of Cost-Benefit Analysis Data Field

Another recurring issue is the continued limited usefulness of Data Field 66, Cost-Benefit Analysis. As with the June cycle, this cycle's responses and discussion suggest that SCE may consider cost, alternatives, and practical execution constraints in project planning, but the PS itself still provides very little structured information that allows Stakeholders to understand how those considerations were weighed.

[15] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slide 17.
[16] ED-SCE-TPR-Cycle 4-2025-003 Q.02.
[17] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slides 23, 24.

CPUC Staff understand that many transmission projects are compliance-driven, policy-driven, or directly tied to reliability or asset-condition needs. But Stakeholders seek to understand whether alternatives were considered, whether the chosen scope reflects a proportional response to the identified need, and whether the utility is learning from prior projects in ways that reduce unnecessary cost. When Field 66 remains vague or empty, Stakeholders lose visibility into this part of project planning.

SCE did not produce a project-specific Cost-Benefit Analysis case study to a level that would be useful in the TPR Process.[18] CPUC Staff therefore continue to believe that SCE should, in future cycles, provide at least a few concrete examples showing how practical cost considerations influenced project selection or scope. This would materially improve the usefulness of Field 66.

AACE Class and Cost Estimate Maturity

AACE class remains an important but inconsistently used data field in the PS. CPUC Staff continued to identify projects where the reported AACE class was difficult to reconcile with the project's apparent life-cycle stage. SCE's explanation is that the class shown in the PS reflects the class assigned when the estimate was prepared and may not be updated until a later estimate is generated.[19]

This approach impedes the usefulness of the field. If a project can remain in advanced construction while still displaying an estimate class associated with a much earlier stage, then the field does not provide meaningful information about the current maturity of the cost estimate supporting the project. CPUC Staff encourage SCE to continue efforts to keep the AACE categorizations up to date so the field is useful for Stakeholder analysis and project understanding.

AFUDC and Extended Schedules

Allowance for Funds Used During Construction (AFUDC) was a significant topic in the December 2025 cycle, with both Stakeholder discussion and data requests focusing on how carrying costs are calculated, controlled, and reflected in project cost reporting. In addition to high-level discussion of AFUDC methodology, this cycle included more detailed information regarding internal controls and processes used to manage AFUDC accrual.

At the Stakeholder meeting, SCE described its general approach to AFUDC and its treatment within the PS, including how AFUDC is calculated based on construction expenditures and applied financing rates over the duration of a project.[20] Stakeholder questions focused on how AFUDC is incorporated into total project cost and whether it can be distinguished from direct construction costs when evaluating cost changes.

[18] ED-SCE-TPR-Cycle 4-2025-002 Q.56 Response and SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slide 28.
[19] ED-SCE-TPR-Cycle 4-2025-002 Q.55 Response and SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slide 60.
[20] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slides 47-49.

Data request responses and supporting materials provided additional detail regarding internal processes for managing AFUDC accrual when projects are delayed or placed on hold.[21] These processes include identifying projects that are not expected to incur significant charges over a defined period (e.g., six months or longer) and implementing procedures to suspend AFUDC accrual for those work orders.

The interaction between AFUDC and project scheduling was also a key theme in this cycle. Because AFUDC accrues over the duration of construction, delays in project execution, whether due to permitting, supply chain constraints, or prioritization decisions, can increase total project cost through additional carrying costs even where direct construction scope remains unchanged. Data requests in this cycle sought to better understand how such schedule changes are reflected in cost updates and how AFUDC is incorporated into revised project estimates.[22]

Stakeholder inquiry also focused on the transparency of AFUDC within the PS. Because AFUDC is embedded within total project cost fields, it may not be readily distinguishable from direct construction costs without additional supporting information. This can complicate efforts to isolate the drivers of cost increases, particularly where cost growth is attributable to extended project timelines rather than changes in scope or design.

Information gathered in the December 2025 Cycle reflects two related areas of focus: (1) the accuracy and consistency of AFUDC calculation and application, and (2) the visibility of AFUDC as a component of total project cost. The discussions in this cycle suggest that additional information on AFUDC triggers, constraints, and sequence justification within the PS notes would improve Stakeholders' ability to evaluate cost drivers and interpret changes across reporting periods.

Overall, AFUDC in this cycle was addressed not only as a cost component but also as a process and control issue. The December 2025 Cycle included more detailed information on AFUDC management practices, highlighting the continued importance of clear linkage between project schedules, cost updates, and carrying cost accrual within the TPR framework.

Transmission Conductors[23]

SCE discussed transmission conductors at the March 2, 2026 Stakeholder Meeting in the context of material selection, system performance, and reliability. SCE described its use of a range of conductor types across past and current projects, including copper, aluminum, and aluminum conductor steel reinforced (ACSR), as well as more recently deployed advanced conductors.

SCE indicated that it has piloted and installed advanced conductor technologies such as aluminum conductor steel supported (ACSS), and composite core conductors including aluminum conductor carbon reinforced (ACCR) and aluminum conductor carbon core (ACCC).

[21] SCE AFUDC and Deferral List Job Aid. Section 4, Procedures. "How to Place a Project on Hold".
[22] ED-SCE-TPR-Cycle 4-2025-001, Q.01-07.
[23] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slides 51 and 52, and ED-SCE-TPR-Cycle 4-2025-003 Q.09 Response.

The utility stated that it is moving toward standardization of ACSS and ACCC for future projects, reflecting a shift toward higher-capacity conductor options.

The selection of conductor type is based on project-specific engineering and cost considerations. SCE explained that, for reconductoring or upgrade projects, different conductor options are evaluated to meet electrical performance requirements while minimizing the need for structural modifications. This includes assessing conductor loading impacts on existing structures, such as tension, diameter, and weight, and comparing those impacts to structural capabilities.

Cost-effectiveness is evaluated through comparison of total project cost, timeline, and risk across design alternatives. SCE indicated that conductor selection reflects a balance between achieving required system performance and managing construction complexity and cost.

SCE also provided information on reliability impacts, noting that there were nine transmission outages in the past 12 months attributable to conductor failure, with causes including storm damage, aircraft strike, vandalism, and conductor parting. These events highlight the importance of conductor condition and material selection in maintaining system reliability.

In addition, SCE described its approach to reconductoring and related structural decisions, including criteria for tower raising. Tower raising may be selected as an alternative to full structure replacement where it reduces cost, scheduling challenges, or environmental impacts, or where reconductoring alone does not provide sufficient benefit.

Overall, the discussion reflects an increasing reliance on advanced conductor technologies to support system capacity and performance, alongside continued consideration of cost, constructability, and reliability in conductor selection and project design.

Grid Enhancing Technologies[24]

Grid Enhancing Technologies (GETs) were also discussed at the March 2, 2026 Stakeholder Meeting as part of system planning and transmission capacity optimization. The discussion focused on improving utilization of existing infrastructure through enhanced transmission line ratings, monitoring, and operational flexibility.

SCE identified specific technologies under evaluation, including Ambient Adjusted Ratings (AAR), Dynamic Line Ratings (DLR), advanced conductors, and advanced voltage control, noting that these technologies are evaluated alongside traditional transmission solutions in coordination with CAISO through the TPP.

SCE also described ongoing efforts related to implementation and assessment, including feasibility reviews of candidate DLR and advanced conductor projects, as well as systemwide implementation of AAR to comply with FERC Order 881. These technologies are intended to

[24] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slide 30.

improve visibility into real-time system conditions, enhance transmission line ratings, and support more efficient use of existing capacity.

Stakeholder questions focused on how GETs are incorporated into planning decisions and the extent to which they can mitigate congestion or defer traditional transmission upgrades. SCE noted that broader deployment depends on factors such as cost recovery, operational integration, and regulatory considerations.

SP-10 Riverside Transmission Reliability Project (RTRP)

RTRP remains one of the highest profile projects in SCE's portfolio and one of the clearest examples of why a long-term project should be tracked not only for current-year cost deltas, but for the cumulative consequences of delay over time. The project's estimated cost rose from about $588 million in June 2025 to about $730 million in December 2025, a roughly $142 million increase. CPUC Staff specifically requested a component-level explanation for that increase.

SCE's response was more detailed than previous cycle's responses and shows that the increase is not attributable to a single cause. Instead, it reflects environmental monitoring, property acquisition and easement work, deeper underground civil construction, larger foundations, more substation civil work, higher overhead, and contingency.[25] At the March 2, 2026 Stakeholder Meeting, SCE added that the budget being discussed had moved even higher, to approximately $756 million. SCE tied the increase to final engineering scope revisions, property costs, and inflation from the time of the original cost estimate to the present.[26]

The cost increase appears to confirm that the prior estimate materially understated the civil complexity of the underground and substation work. In addition, the project remains exposed to risks that are not fully under SCE's control, including local permitting, public opposition, Riverside Public Utilities' schedule, and external findings during construction. Because the project has now been delayed by roughly two decades relative to the original reliability need, delay-related cost responsibility remains a legitimate concern.

SP-01 Calcite Substation Construction

Calcite is one of the most important projects in the December cycle because it brings together several recurring TPR issues at once: generator interconnection, tariff-based cost responsibility, schedule delay, and the question of how a project can persist after the interconnection landscape changes from when a project is first approved. CPUC Staff's first question focused on the most visible change between cycles: an approximately 23-month delay.

SCE's response attributed the delay primarily to the County of San Bernardino's California Environmental Quality Act (CEQA) and permitting process for the Avantus Sienna projects and to the appeal of those approvals, which was not resolved until January 2026. Unlike

[25] ED-SCE-TPR-Cycle 4-2025-002 Q.19 Response.
[26] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slides 93 and 94.

some other projects in this cycle, SCE stated that no additional cost increase was expected over the estimated $97.336 million total cost as a result of the delay.[27]

Additional data requests addressed the project's development history and basis for continued cost responsibility. SCE explained that the project was originally identified through earlier interconnection studies and remained part of the CAISO interconnection base case used for subsequent studies, even after the termination of the original interconnection agreement. As a result, the project continues as a network upgrade under CAISO tariff provisions.[28]

CPUC Staff remain concerned that this kind of project trajectory makes cost responsibility difficult to evaluate. While the immediate delay may be attributable to County permitting and CEQA appeals, and the current construction timeline may now be considered low risk, the underlying project still raises legitimate questions about how much of its cost should ultimately be borne by transmission customers, how reimbursement limits should be interpreted in light of present megawatt output, and whether the utility should provide clearer explanations whenever a project's current set of interconnection customers is meaningfully different from the one under which the network upgrade originally became SCE's responsibility.

SP-24 Cerritos Channel Tower Relocation

The estimated project cost of Cerritos Channel Tower Relocation rose from approximately $76.1 million in June 2025 to about $117.7 million in December 2025, a 35 percent increase. Because the increase was so large, CPUC Staff asked whether the scope of the project had changed, whether new technical challenges had emerged, or whether the increase stemmed from revised contractor pricing and schedule.

SCE's response was that the project scope had not changed. Instead, the cost increase was driven by receipt of only one vendor bid for underwater foundation removal and by higher SCE forecasted costs associated with the project's longer duration.[29] The March Stakeholder Meeting discussion was consistent with that explanation and added detail on the current risks, the failed first procurement effort, and the decision to rebid.[30]

SP-26 Control-Silver Peak TLRR Remediation

SP-26 (Control-Silver Peak TLRR Remediation) was discussed during the March 2, 2026 Stakeholder Meeting in the context of project cost updates and underlying estimate assumptions. CPUC Staff sought clarification regarding the drivers of the observed cost increase, including the extent to which escalation factors and the vintage of prior cost estimates contributed to the updated project cost. SCE explained that the June 2025 estimate was still grounded on a 2021

[27] ED-SCE-TPR-Cycle 4-2025-002 Q.18 Response.
[28] ED-SCE-TPR-Cycle 4-2025-003 011 Response.
[29] ED-SCE-TPR-Cycle 4-2025-002 Q.21 Response.
[30] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slide 89.

cost basis and that the project's prolonged regulatory process had made that earlier estimate increasingly outdated.[31]

When a project is known to be progressing slowly through licensing or environmental review, Stakeholders need visibility into when a cost estimate is becoming stale enough that it no longer serves as a meaningful planning estimate. As no data provided in the TPR PS should be more than 60 days old, such stale cost estimates do not appear to meet the expectations of Resolution E-5252:

> *For any project meeting [the criteria of the TPR Process], the Project Spreadsheet must be fully populated for each Project with data extracted from the Utility's database no more than 60 days prior to the data being provided.*[32]

PB-16.29 - Barre Substation MEER Build and Satellite Substations

PB-16.29 (Barre Substation MEER Build and Satellite Substations) was the subject of targeted data requests in the December 2025 cycle, with CPUC Staff seeking additional detail regarding both project scope and cost estimate maturity. Specifically, data requests sought identification of the full set of satellite substations included in the expanded scope, as well as a summary of the associated equipment, outage requirements, and construction sequencing assumptions. CPUC Staff also requested clarification regarding the basis for the assigned AACE Class estimate, given the project's reported status.[33]

The need for these clarifications reflects the complexity inherent in projects that incorporate multiple substation elements under a single programmatic scope. Without detailed breakdown of individual components, it is difficult to assess whether the reported cost estimate appropriately reflects the level of project definition or to evaluate potential variability across sites. Additional transparency into scope granularity and cost estimate maturity would improve the ability of Stakeholders to assess cost risk and project readiness. Continued monitoring of PB-16.29 in future cycles is warranted, particularly as scope definition and cost estimates evolve.

SP-154 — North of SONGS–Serrano 500kV Competitive Project

SP-154 (North of SONGS–Serrano 500kV Competitive Project) was the subject of targeted inquiry in the December 2025 cycle with respect to system reliability during the period prior to project energization. CPUC Staff requested that SCE describe the interim reliability approach under the current in-service timeline, reflecting the importance of maintaining system performance while large transmission projects are under development.[34]

The focus of this inquiry highlights a key consideration for projects with extended development timelines: the potential gap between identification of system need and the availability of long-term infrastructure solutions. While there do not appear to be material

[31] SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slide 97.
[32] Resolution E-5252, Attachment A, Section 2.1 – Information on Transmission Projects
[33] ED-SCE-TPR-Cycle 4-2025-004 Q.01.
[34] ED-SCE-TPR-Cycle 4-2025-004 Q.02.

changes to project scope or cost in this cycle, the need for interim reliability planning suggests that the project plays a role in addressing system conditions that require near-term mitigation. Additional clarity regarding the nature and duration of interim measures would improve transparency into how reliability risks are managed prior to project completion.

SP-204 - Serrano 500kV Short Circuit Duty Mitigation

SP-204 (Serrano 500kV Short Circuit Duty Mitigation) was the subject of data requests in the December 2025 cycle focusing on post-mitigation system conditions and project sequencing assumptions. CPUC Staff requested information regarding expected short circuit duty margins following project completion, as well as the assumed in-service sequencing of dependent projects that contribute to increased fault duty levels.[35]

This line of inquiry reflects the technical complexity associated with short circuit duty mitigation projects, which are often sensitive to the timing and configuration of other system elements. The need to understand both final system conditions and interim assumptions underscores the importance of clearly documenting dependencies and sequencing logic. There were no significant cost or schedule changes for SP-204 in this cycle, but the reliance on broader system assumptions suggests that continued monitoring is appropriate to ensure that project timing and expected outcomes remain aligned with evolving system conditions.

Etiwanda-Related Projects[36]

Projects associated with the Etiwanda area were discussed at the March 2, 2026 Stakeholder Meeting in the context of transmission upgrades, substation improvements, and system reliability. The discussion included both programmatic investments and specific projects intended to support capacity, operational flexibility, and long-term system performance in the Inland Empire region.

At a programmatic level, SCE presented updates on substation-related investments at Etiwanda, including PB-14.06 Etiwanda Substation: SA3 Hybrid Solutions and PB-18 Substation Transformer Bank Replacement Program. These programs reflect ongoing efforts to modernize substation infrastructure, replace aging equipment, and improve system performance through targeted upgrades.

The Stakeholder meeting also included discussion of multiple transmission projects in the Etiwanda corridor, including SP-168 Vista-Etiwanda 230kV Line 1 Upgrade and SP-169 San Bernardino–Etiwanda 230kV Line 1 Upgrade. These projects are part of a broader set of transmission reinforcements intended to increase capacity and reliability by upgrading existing lines and supporting system configuration in the area.

Collectively, the Etiwanda-related projects reflect a coordinated approach to addressing both localized and system-level needs. Substation programs support asset condition and

[35] ED-SCE-TPR-Cycle 4-2025-004 Q.03.
[36] SCE TPR Stakeholder Meeting Presentation, March 2, 2026. (PB-14.06 Slide 70, PB-18 Slide 73, SP-168 Slide 75, SP-169 Slide 82).

operational flexibility, while transmission upgrades address capacity constraints and facilitate power flows across the network. The combination of these investments suggests that the Etiwanda area remains a focal point for infrastructure upgrades driven by reliability requirements, load growth, and broader system integration needs.

SP-162: Brightline West High-Speed Rail Project and SP-152 New Coolwater A 115/230kV Bank

Projects associated with the Brightline West transmission system, including the New Coolwater-related facilities, were referenced during the March Stakeholder Meeting, but no meaningful work appears to be underway on the Brightline West Project in 2026 due to customer delays, and SCE indicated that they are re-assessing the need for the New Coolwater A project as part of their current (2025-2026) TPP process.[37] These projects are tied to the Brightline West high-speed rail initiative and reflect a class of transmission investments driven by large, externally sponsored infrastructure development. As such, they are dependent on third-party project timelines, assumptions regarding load and energization, and coordination with non-utility Stakeholders. These projects continue to present potential exposure related to schedule alignment, scope evolution, and cost recovery considerations, particularly if underlying project assumptions change. Accordingly, continued monitoring in future TPR cycles is warranted to assess consistency between transmission development milestones, the status of the associated Brightline West projects, and matters of cost causation.

**Conclusion**

The December 2025 TPR Cycle builds on the structure and content developed in SCE's prior reporting periods. SCE's submission included a broad portfolio of programmatic and specific projects, with total projected costs increasing relative to the June 2025 cycle. This is partly due to the increased 2030 forecast capital expenditures and the removal of the 2020 capital expenditures, which are no longer required reporting starting with this December 2025 PS. However, most of the change is attributable to updates in scope, schedule, and cost assumptions on existing large projects.

The Stakeholder meeting held on March 2, 2026 provided a structured forum for review of the submission and discussion of both process-level topics and project-specific issues. The agenda covered core TPR topics, including data quality, supply chain constraints and advance procurement, utility prioritization practices, cost-benefit analysis field utilization, AACE class, AFUDC, and TLRR, as well as several high-interest projects. Together with SCE's data request responses, the meeting contributed to a more complete set of information for evaluating the December 2025 submission.

[37] SCE TPR Process Dec 2025 Cover Letter December 1, 2025 and SCE TPR Stakeholder Meeting Presentation, March 2, 2026, Slide 103. Currently still "on hold" as of the CAISO's 2025-2026 Draft Transmission Plan (page 168).

Project-level review remained a central component of the cycle. Certain projects were the subject of targeted data requests and more detailed discussion, reflecting issues such as cost increases, schedule changes, permitting constraints, and cost responsibility under applicable tariff provisions. Other projects were addressed at a higher level, consistent with their scale and the extent of changes in estimated costs and in-service dates between reporting periods.

Issues Addressed in the December Cycle

The December 2025 cycle addressed several issues identified in prior comments, including improvements in data quality, Stakeholder engagement, and organization of the Stakeholder Meeting. SCE confirmed that no major methodological changes were introduced in this cycle, indicating increased stability in the PS development process. The Stakeholder Meeting was structured around key TPR topics and provided more focused opportunities for discussion, with follow-up data requests used to address outstanding questions.

While the PS development process is more predictable, data quality remained an area of continued focus. SCE acknowledged formatting issues and isolated inconsistencies in the PS, including truncated fields and data entry errors, and indicated that additional validation and formatting checks are planned for future cycles. These issues, while limited in scope, highlight the importance of continued attention to data accuracy and consistency as the PS evolves.

Several thematic areas received more detailed attention in this cycle. Supply chain constraints and advance procurement were discussed in the context of managing long-lead equipment and coordinating across projects. Utility prioritization practices were examined through data requests focused on how schedule changes are documented and how competing project needs are addressed within the PS.

Cost reporting and estimate maturity were also addressed. SCE clarified that AACE class reflects the estimate at the time it is prepared and is updated only when a new iteration of the estimate is developed. Future cycles therefore warrant continued focus on how SCE determines when a project estimate is mature enough to be presented as a planning baseline and when it must be updated because scope, permitting, procurement, or market conditions have made earlier estimates no longer reliable.

AFUDC was discussed in greater detail than in prior cycles, including both methodology and internal controls, with particular attention to the relationship between project schedules and carrying cost accrual.

Project-specific discussions addressed a range of recurring issues. Large projects were examined in greater detail due to cost changes, schedule developments, and project complexity. These discussions reflect ongoing areas of focus within the TPR process, including permitting and external dependencies, interconnection-related cost responsibility, and construction-related cost drivers.

The cycle also included discussion of generator interconnection and CAISO-driven projects, including both GIDAP-related upgrades and TPP-approved projects. These discussions continue to highlight the role of external drivers in transmission planning and the importance of clearly documenting their impact on project scope, timing, and cost.

Next Steps and Areas for Continued Improvement

While the December 2025 cycle reflects continued progress, several areas warrant ongoing attention in future reporting periods. Continued improvements in data quality and validation processes will be important to ensure the accuracy and usefulness of the PS. This includes addressing formatting issues, improving field consistency, and ensuring that updates are clearly reflected across reporting cycles.

Additional clarity in the documentation of project-level assumptions would enable more effective Stakeholder involvement in the TPR process. This includes more consistent explanation of project scope, schedule drivers, and cost changes, particularly where those changes are driven by external factors such as permitting, interconnection activity, or system conditions. Cost transparency also remains an important area for refinement. Enhanced visibility into the components of total project cost, including the effects of schedule changes and AFUDC accrual, would improve Stakeholders' ability to evaluate cost drivers and interpret changes over time. Similarly, clearer linkage between prioritization decisions, schedule updates, and reported project data would support a more complete understanding of project sequencing.

Continued engagement through Stakeholder meetings and data request processes will remain critical. The December cycle demonstrates the value of structured discussion and responsive follow-up in developing more complete information. Maintaining this level of engagement, while continuing to refine the organization and content of both meetings and supporting materials, will support further improvement of the TPR framework.

Energy Division Staff appreciate SCE's continued engagement in the TPR Process and the additional information provided through the Stakeholder meeting and data request responses. The December 2025 cycle was especially useful in clarifying the drivers of several major cost increases and in clarifying the history and current status of important projects, but continued refinement is needed in several key areas. Ongoing attention to data quality, documentation, and cost transparency will support more effective review and evaluation of transmission projects in future cycles.

CPUC Staff will continue to evaluate SCE's plans to ensure safe, reliable, and affordable electric transmission solutions for California customers. In future cycles, CPUC Staff expects more consistent disclosure of the reasons for schedule changes, and clearer project-level explanation when costs move materially upward.

SCE should direct any questions or comments on the TPR Process to tprprocess@cpuc.ca.gov.