# SCE Transmission Project Review (TPR) Process

## Cycle 4 - Stakeholder Meeting

March 2, 2026

# Roll Call

Jerry Huerta, Senior Attorney

# TPR Meeting Overview, Agenda, Safety, and Meeting Logistics

Mark Khouzam, Senior Advisor
FERC Rates and Tariffs – TPR Team

# Agenda

| Start Time | End Time | Duration | Topic | Presenter(s) |
|---|---|---|---|---|
| 9:00 AM | 9:05 AM | 5 min | Roll Call | J. Huerta |
| 9:05 AM | 9:10 AM | 5 min | TPR Meeting Overview, Agenda, Safety, and Meeting Logistics | M. Khouzam |
| 9:10 AM | 9:20 AM | 10 min | 1. TPR Process Project Spreadsheet Data Quality and Management | T. Antonucci |
| 9:20 AM | 9:30 AM | 10 min | 6. Supply Chain Constraints and Advance Procurement | J. Shedd |
| 9:30 AM | 9:40 AM | 10 min | 18. PB-25 Seismic Mitigation Program – Substations | A. Flores, A. Topoleski |
| 9:40 AM | 9:50 AM | 10 min | 16. GIS Rebuilds | A. Flores |
| 9:50 AM | 10:00 AM | 10 min | 2. Utility Prioritization Ranking (Field #25) | S. Mascarenhas |
| 10:00 AM | 10:10 AM | 10 min | 4. Cost-Benefit Analysis Field Utilization (Field #66) | M. Avendaño |
| 10:10 AM | 10:20 AM | 10 min | 11. Grid Enhancing Technologies | M. Avendaño |
| 10:20 AM | 10:35 AM | 15 min | 27. SP-151 New Lugo 3AA 500/230 kV Bank | E. Webb |
| 10:35 AM | 10:45 AM | 10 min | Break | |
| 10:45 AM | 11:00 AM | 15 min | 7. Generator Interconnection Network Upgrades and CAISO TPP Reliability and Policy-Driven Projects | F. Benavides, B. Coalson, O. Santos |
| 11:00 AM | 11:15 AM | 15 min | 14. Remedial Action Schemes | F. Benavides |
| 11:15 AM | 11:30 AM | 15 min | 26. Incentives Received on Projects Related to Tehachapi Renewable Transmission Project (TRTP) | F. Benavides |
| 11:30 AM | 11:45 AM | 15 min | 5. Allowance for Funds Used During Construction (AFUDC) | J. Jacobs, J. Califano |
| 11:45 AM | 12:00 PM | 15 min | 13. Transmission Conductors | B. Powell |
| 12:00 PM | 12:30 PM | 30 min | Lunch | |

*** Please note that Topics are numbered in order received from the CPUC and Stakeholders, but the order here has been reorganized in order to accommodate speakers.**

# Agenda (continued)

| Start Time | End Time | Duration | Topic | Presenter(s) |
|---|---|---|---|---|
| 12:30 PM | 12:40 PM | 10 min | 9. Data Centers | O.Marroquin |
| 12:40 PM | 12:45 PM | 5 min | 10. Transmission-Level Electric Vehicle Charging | O.Marroquin |
| 12:45 PM | 12:55 PM | 10 min | 3. AACE Class – Project Cost Estimate Maturity (Field #48) | P. Tran, J. Huang |
| 12:55 PM | 1:05 PM | 10 min | 12. Transmission Line Rating Remediation (TLRR) | B. Wheatley |
| 1:05 PM | 1:20 PM | 15 min | 8. Physical and Cyber Security-Related Projects | E. Hall |
| 1:20 PM | 1:25 PM | 5 min | 15. Wildfire Impacts | A. Ocegueda |
| 1:25 PM | 1:35 PM | 10 min | 19. PB-14.06 Etiwanda Substation: SA3 Hybrid Solutions | M. O'Brien |
| 1:35 PM | 1:45 PM | 10 min | Break | |
| 1:45 PM | 1:55 PM | 10 min | 20. PB-18 Substation Transformer Bank Replacement Program | E. Kamphuis |
| 1:55 PM | 2:05 PM | 10 min | 30. SP-168 Vista–Etiwanda 230 kV 1 Line Upgrade | C. Mirabueno |
| 2:05 PM | 2:20 PM | 15 min | 21. SP-01 Calcite Substation | H. Arshadi |
| 2:20 PM | 2:30 PM | 10 min | 31. SP-169 San Bernardino–Etiwanda 230 kV 1 Line Upgrade | H. Arshadi |
| 2:30 PM | 2:45 PM | 15 min | 22. SP-04 Alberhill Substation Loop In | M. Bass |
| 2:45 PM | 2:55 PM | 10 min | 24. SP-24 Cerritos Channel Tower Relocation | M. Bass |
| 2:55 PM | 3:10 PM | 15 min | 23. SP-10 Riverside Transmission Reliability Project | K. Spear |
| 3:10 PM | 3:20 PM | 10 min | Break | |
| 3:20 PM | 3:30 PM | 10 min | 25. SP-26 Control–Silver Peak TLRR Remediation | M. Orozco |
| 3:30 PM | 3:45 PM | 15 min | 17. PB-05 Substation Unplanned Capital Maintenance and PB-06 Substation Planned Maintenance Program | M. Christensen |
| 3:45 PM | 4:00 PM | 15 min | 28. SP-152 New Coolwater A 115/230 kV Bank | R. Preijers, S. Montes |
| 4:00 PM | 4:15 PM | 15 min | 29. SP-154 North of SONGS – Serrano 500 kV Line Project (Competitive Project) | A. Gutierrez |
| 4:15 PM | 4:20 PM | 5 min | Close Out & Next Steps | A. Ocegueda |

*** Please note that Topics are numbered in order received from the CPUC and Stakeholders, but the order here has been reorganized in order to accommodate speakers.**

# Virtual Meeting Emergency Protocol

## VIRTUAL MEETING EMERGENCY PROTOCOL

Follow these steps when a virtual or hybrid meeting attendee is incapacitated.

### BEFORE THE MEETING STARTS - **ASSIGN ROLES**

- Who will call ESOC? **(626-815-5611)**
- Who will contact the leader?
- Who will stay on the call with the employee?
- Identify the location of employees who may be in transit or out in the field.

1. A medical emergency occurs, or seems to be occurring.
2. If you know the employee's location, call 911.
   Katelyn Wright
3. Call Edison Security Operations Center (ESOC) at **626-815-5611.**
   Antonio Ocegueda
4. If 911 has not been called, ESOC will contact 911 to dispatch emergency services to employee's home address.
5. Contact the employee's leader.
   Rob Mindess
6. Remain on the line with the employee until emergency services arrives.
   Mark Khouzam

If employee is a supplemental worker, ESOC will contact the vendor to provide known information; if unavailable, 911 will be contacted.

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# Safety Moment – Cold Weather Safety Precautions

# TPR Overview and Meeting Objectives

- The Transmission Project Review Process provides the Commission and all Stakeholders semi-annually with current, specific, comprehensive, and system-wide transmission data for projects with capital additions to rate base in the last five years and forecasted or actual capital expenditures in the current year and future four years
- SCE hosts a semi-annual Stakeholder Meeting on February 28 and August 28, to engage and address Stakeholder's questions and discussion topics
  - SCE has made a good faith effort to identify the appropriate subject matter experts to speak on each topic and to provide accurate information throughout this presentation but reserves the right to correct or supplement the information provided if it becomes aware of needed modifications or additions

# General Meeting Logistics

- No NERC CIP confidential information will be discussed
- AI recording bots are not permitted, and will be kicked out of meeting
- Please mute your line if you are not speaking
- Presenters will take questions at the end of their section
- Please use raise your hand (icon) and we will call on you in the order it was raised; Reminder to put hand down after question
- When asking questions, please state your name and organization first
- Teams Chat feature is also available for questions (see next slide)
- Presenters will be joining throughout the day at specific times, so we will work to stay on schedule
- SCE welcomes your feedback on how to improve the stakeholder calls during next steps and in written comments

# Teams Chat

- During the presentation, stakeholders may also ask questions using the Chat feature
  - Questions should be submitted during the topic presentation, so that the speaker may address them
  - The SCE team will strive to address any remaining questions that are not answered during the topic timeslot as the stakeholder call progresses
- Questions submitted via Chat do not constitute discovery submittals, which must be provided separately in accordance with the TPR Resolution and its attendant process timelines

# SCE's December 2025 TPR Materials & Questions Received

- SCE's December 2025 TPR Project Spreadsheet included all FERC-jurisdictional electric transmission projects with actual or forecasted capital costs of one million dollars or more in the prior five calendar years, the current year, or the next four years (2021 – 2030)
- SCE's December 2025 TPR Submission included:
  - Project Data Spreadsheet included a total of 508 rows comprised of: 48 Program Blankets, 319 programmatic projects, and 141 Specific Projects
  - 152 Public, 4 Confidential, and 15 CEII Authorization Documents that correspond to Projects in the Spreadsheet
  - No new procedures were added in Cycle 4
  - SCE addendum for AB970 eligible projects that would otherwise be subject to the TPR >$1M threshold in accordance with the CPUC Decision 25-01-040
- SCE received two data request sets from Energy Division
  - Cycle 4 – ED - DR Set 1 -  7 questions with subparts
  - Cycle 4 – ED - DR Set 2 – 56 questions with subparts
- 31 topics with subparts for today's discussion were received from the CPUC (in coordination with other stakeholders)

# TPR Process Milestones

| Date | Milestone |
|---|---|
| December 1 | SCE provides semi-annual Project Data Spreadsheet and project authorization documents to Stakeholders |
| January 15 | Deadline for Stakeholders to provide questions/ comments |
| February 6 | SCE publishes written responses to questions / comments |
| February 13 | CPUC and Stakeholders provide agenda items for Stakeholder meeting |
| March 2 | SCE hosts Stakeholder meeting |
| March 16 | Stakeholders provide questions/ comments within 15 calendar days following Stakeholder meeting |
| April 6 | SCE publishes written responses to questions/ comments |
| April 13 | Deadline for Stakeholders to provide project-specific follow-up questions/ comments |
| April 27 | SCE publishes written responses to project-specific follow-up questions/ comments |
| April 30 | Stakeholders may provide comments to SCE by this date |
| June 1 | Repeat |

# 1. TPR Process Project Spreadsheet Data Quality and Management

Tom Antonucci, Sr. Manager – Technical Compliance

# SCE TPR Project Spreadsheet

**Please provide an overview of SCE's process for compiling and validating the TPR Process Project Spreadsheet, noting any changes since the last cycle.**

- SCE's process comprises the following steps:
  1) The set of in-scope projects is determined
  2) A working spreadsheet is initially populated using the previous TPR submission and an automated pull of some data sources (where available)
  3) SMEs review/update the initial data and populate blank cells
  4) Project managers and leaders review the completed spreadsheet

- The Dec-2025 process introduced the following improvements:
  - An automated initial pull of available data sources
  - Automation of some data and formatting checks
  - FERC Rate Base data is now pulled directly from a source system (PowerPlan)

- The Jun-2026 process will introduce the following improvements:
  - Extra spaces will be "trimmed" and not flagged as changes
  - Key visual aspects of the spreadsheet are being improved to aid SMEs and reviewers during the process
  - A scan of changes that occur during review will be implemented

# SCE TPR Project Spreadsheet

**Please explain the issues encountered in preparing the December 2025 spreadsheet, including the data errors that required correction, and describe the corrective actions and process improvements planned for future cycles.**

- <u>Two items required correction in the Dec-2025 submission:</u>
  - Many cells with line breaks were inadvertently truncated
  - One project (SP-04) was incorrectly classified as “Utility Approved”

- <u>Truncated text</u>
  - Occurred during an automated operation on the spreadsheet
  - Visually undetected because cell size was typically smaller than truncation point
  - SCE is in the process of implementing conditional formatting which would flag this type of change to the spreadsheet. (Semi-manual check will be fallback approach.)

- <u>SP-04</u>
  - “Utility Approved” field was changed incorrectly at the end of the review process
  - SCE is in the process of implementing conditional formatting which would flag this type of change to the spreadsheet in real time. (Semi-manual check will be the fallback approach.)
  - SCE is developing a process improvement to make spreadsheet visual cues more effective
  - SCE is implementing a final scan of reviewer changes to look for flags

# 6. Supply Chain Constraints and Advance Procurement

Jeremy Shedd, Interim Principal Manager, Direct Materials Procurement

# Supply Chain Constraints and Advance Procurement

**a) Please explain whether SCE is encountering any supply chain issues for transformers, circuit breakers, and other critical transmission-related infrastructure. If it is, please explain them and describe SCE's plans to address.**

Edison is encountering persistently extended lead times for critical power transformer (up to 156 weeks) and circuit breaker (up to 240 weeks) equipment. Edison released a series of competitive RFPs and negotiated production slot reservations to cover forecasted demand through 2032, however unplanned, engineered-to-order equipment remain at risk.

**b) Please provide an update on SCE's advance procurement of transformers and circuit breakers, both for emergency inventory and known projects. Please include updates on the preferred manufacturers/production slot reservation strategy and the work order process improvement pilot. Include examples of tangible results from the slot reservation strategy and process pilot (money saved, delays averted, etc.), as well as a description of challenges encountered.**

Since 2024, Edison reserved production slots for over 300 power transformers and circuit breakers based on forecasted demand. As the planning time horizon advances, Edison plans to negotiate over 100 additional production slot reservations in 2026 to mitigate the potential for project delays due to the extended lead times in the current market.

**c) Please describe how new or proposed tariffs are affecting the cost and availability of transformers, circuit breakers, and other critical transmission-related infrastructure, and whether a particular category of project (reliability, policy, etc.) is more impacted than others by supply chain constraints and tariffs.**

Edison has not experienced challenges with availability due to tariffs, however the cost of finished goods, sub-components, and raw materials are affected. The largest impact is IEEPA, section 301 and 232 tariffs. Edison continues to use competitive pressure, alternate sources, and negotiations with suppliers to minimize the impact of tariffs. Edison will also pursue reimbursement if the opportunity arises.

# 18. PB-25 Seismic Mitigation Program – Substations

Adrian Flores, Sr. Project Manager – Major Construction

Amber Topoleski, Senior Advisor, Business Continuity

# PB-25 Seismic Mitigation Program – Substations

**Please provide an update on this program and an update on major projects under each. Please include in the discussion any notable risks or challenges to the program.**

- SCE's Substation Seismic Mitigation Program currently includes a total of 17 active projects at various stages of execution. The program status is as follows:
  - Projects projected for completion in **2026** (**12 total**):
    - 9 projects scheduled to begin construction in 2026
    - 3 projects currently in active construction
  - Projects projected for completion in **2027** (**4 tota**l):
    - 4 projects in active design
  - Projects projected for completion in **2028** (**1 tota**l):
    - 1 project in active design

- SCE has identified notable risks impacting substation seismic projects, including:
  - Customer outage coordination
  - Competing work scopes at the substation

# 16. GIS Rebuilds

Adrian Flores, Sr. Project Manager, Major Construction

# GIS Rebuilds

**Please identify any Gas-Insulated Substation (GIS) rebuild projects in SCE's pipeline that meet TPR Process criteria, including the estimated cost, what cost-benefit analyses were conducted, which alternatives were considered, and why GIS was ultimately selected.**

- Serrano Substation 4AA 500/220kV Transformer Bank and 220kV GIS Rebuild Project - $212M (SP-154)
  - Alternatives considered:
    - Build new 500kV line, add a new bank, and upgrade 220kV
    - Construct new greenfield 220kV open air switch rack and add new bank
- Serrano Substation 500kV GIS Short Circuit Duty Project- $68M (SP-204)
  - Alternatives considered – limited due to already moving forward with other GIS expansion scopes at Serrano Substation

- Cost-Benefit analyses: Each alternative was looked at for cost, constructability, electrical needs, projected duration, projected need for licensing, etc.

- GIS was selected as based on the alternatives analysis it provided the most benefit for the least estimated cost

# 2. Utility Prioritization Ranking (Field #25)

Sheridan Mascarenhas, Senior Advisor
Transmission

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# Utility Prioritization Ranking (Field #25)

**Please explain how SCE defines, applies, and governs "prioritization" decisions that affect transmission project sequencing and in-service dates, including**

**a) what SCE means by "prioritization" when it is cited as a reason for changes in in-service dates in Data Field 52**

- 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.

**b) the methodology, criteria, inputs, and governance processes SCE uses to compare and sequence projects across transmission programs when prioritization results in deferrals**

- While SCE does not have a utility-wide prioritization ranking system, need and timing is primarily determined based on factors described in the response to part a)

**c) how asset condition, risk exposure, compliance obligations, and regulatory drivers are incorporated into prioritization decisions when multiple projects compete for limited resources**

- SCE does have some program-specific prioritization methods for asset-based programs. These take asset conditions, risk exposure due to failure & compliance obligations typically driven by regulatory drivers into consideration.

# Utility Prioritization Ranking (Field #25)

**d) how prioritization decisions are documented, reviewed, approved, tracked over time, and communicated internally**

- SCE holds multi-departmental meetings at which prioritization decisions are reviewed. The prioritization of the project is not tracked as SCE does not have a utility-wide prioritization ranking system. Tracking of these changes are done at the project level, through changes in project schedules as well as through regulatory filings.

**e) whether SCE plans to enhance transparency of prioritization information in future TPR Process Project Spreadsheet filings, including population of Data Field 25 or supplemental materials**

- SCE continues to have concerns with providing limited set of prioritization data under Column 25 that is specific to a limited set of programs and not cross-comparable
- However, SCE will continue to explore ways this limited set of data could be provided without causing confusion/misinterpretation

# Utility Prioritization Ranking (Field #25)

**f) how the asset categories, prioritization concepts, and evaluation factors presented in the Utility Prioritization worksheet are applied consistently to individual projects reflected in the TPR Process Project Spreadsheet and project-level outcomes.**

- SCE prioritizes work under separate single infrastructure replacement programs. For specific programs (e.g., Circuit Breaker/Transformer replacements) SCE uses the following;
  - **Health Index**: An index that scores equipment based on several factors such as age, inspection findings, performance history, test results etc.,
  - **Additional Factors**: Additional factors such as regulatory compliance requirements, technology obsolescence, unavailability of replacement parts, operational or design efficiency etc.
- **Plan / Prioritization Development**
  - Based on these factors, a draft replacement schedule is developed
  - Two adjustments are then made. First, the draft schedule is adjusted by SMEs
  - Second, the schedule is adjusted to optimize for construction efficiencies

**g) whether a particular category of project (reliability, policy, etc.) is more impacted than others by in-service date changes due to "prioritization."**

- SCE believes that no specific category is more adversely impacted than others. SCE prioritizes work based on several factors such as resource and/or outage constraints, compliance, CAISO TPP approval timing, third party executed agreements or other contractual/regulatory requirements.

- **See Cycle 4 CPUC Data Request #2-54 for further information**

# 4. Cost-Benefit Analysis Field Utilization (Field #66)

Manuel Avendaño, Engineering Senior Manager, Central System Planning

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# Cost-Benefit Analysis Field Utilization (Field #66)

**Please provide an update on SCE's incorporation of cost/benefit analyses in its project planning strategy, including**

**a) whether and how SCE plans to formally integrate cost-benefit analysis or quantitative benefit metrics into future transmission project development and justification**

**b) how SCE evaluates non-wires and operational alternatives relative to traditional wires solutions**

**c) any examples or case studies where SCE has applied cost-benefit or quantitative benefit analysis in project selection or design**

**d) how SCE quantifies or otherwise accounts for reliability benefits and risk reduction when justifying and prioritizing projects**

**e) the internal review processes and governance mechanisms used to ensure that non-economic projects**

**f) any planned enhancements to the information reported under Data Field 66 in future TPR Process Project Spreadsheet filings to better convey project benefits or value.**

# How SCE Approaches Cost-Benefit Analysis for Transmission Projects

- **See Cycle 4 CPUC Data Request #2-56**

- SCE does not apply standalone, monetized cost-benefit tests to most transmission projects because they are mandated by reliability, compliance, or CAISO planning requirements. Instead, projects are justified through engineering-based standards, independent CAISO evaluation, and layered internal governance.
- Key takeaways:
  - Reliability and compliance drive investment
  - CAISO performs comparative evaluation
  - Cost-effectiveness ensured through governance, not monetization
  - Reliability benefits are quantified technically, not monetarily
  - Transparency improvements planned
  - Structural barriers remain

# 11. Grid Enhancing Technologies

Manuel Avendaño, Engineering Senior Manager, Central System Planning

# Grid Enhancing Technologies

**Please provide any updates on Grid Enhancing Technologies (GETs) SCE is evaluating (including but not limited to Ambient Adjusted Ratings (AAR), Dynamic Line Rating (DLR), Advance Conductors, Advanced Voltage Control). Include in the discussion whether any GETs projects have been in coordination with the CAISO, and how deployment of these technologies has enhanced grid operation and congestion/constraint mitigation timelines and/or demonstrated cost benefits.**

- **See Cycle 3 CPUC Data Request #2-18**
- **Ongoing Evaluation**. SCE evaluates GETs alongside traditional transmission solutions in coordination with CAISO through the TPP. In the 2025-2026 TPP, SCE proposed two reconductoring with advanced conductor projects
- **SB 1006 Assessment**. Completed feasibility review of nine candidate Dynamic Line Rating (DLR) projects and 58 candidate projects for reconductoring with advanced conductor; provided CAISO with information on technical feasibility, cost, ratings impact, and implementation timelines
- **AAR Implementation**. Actively implementing Ambient Adjusted Ratings (AAR) across the Bulk Electric System in compliance with FERC Order 881
- **Deployment Considerations**. Broader GETs deployment requires resolution of cost recovery, operational integration, and regulatory framework considerations. SCE is exploring state and federal demonstrations efforts

# 27. SP-151 New Lugo 3AA 500/230 kV Bank

Elizabeth Webb, Major Construction Project Manager, TSPM (Transmission, Substation, Project Management)

# SP-151 New Lugo 3AA 500/230 kV Bank

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program. Please include a breakdown of the major cost components of the project. Describe the impact this new bank is expected to have on system operations and reliability.**

- **See Cycle 4 CPUC Data Request 2-27**
- **Scope:** The project scope includes installation of three (3) new 500/230/13.8 kV single-phase transformers and one (1) spare transformer, installation of two circuit breakers and related terminal equipment at the respective 500 kV and 230 kV switchrack positions, and extension of the 230 kV double operating bus at Lugo Substation. SCE will be utilizing spares from the Spare Transformer Equipment Program (STEP) to reduce delays related to long lead equipment
- **Project Drivers**: Mitigation of system reliability risks (thermal overloads, transient instability) with loss of AA banks and increased deliverability of renewable generation from North of Lugo, needed to enable RPS
- **Status**: In pre-engineering and moving forward towards a June 2029 expected completion date
- **Budget:** Current projected cost is $78.1M
- **Major cost components**: Substation work $46M, Transformers $10M, Contingency $18M
- **Risks/Challenges:** If the Lugo–Victorville 500 kV Thermal Overload Project is not completed in 2027; CAISO outage coordination
- **Impact on system operations/Reliability:**
- Will mitigate thermal overloads, reduce renewable generation curtailments, and improve system resilience by allowing continued operation following loss of one or two existing AA banks at Lugo Substation
- **Schedule:** Engineering 4/26-10/27, Construction Start 1/28, OD 6/29

# Break – 10 minutes

# 7. Generator Interconnection Network Upgrades and CAISO 2024/2025 TPP Reliability and Policy-Driven Projects

Fernando Benavides, Senior Advisor – Integrated Major Project Development

Ben Coalson, Senior Engineer – Integrated Major Project Development

Odet Bonilla Santos, Senior Manager, Integrated Major Project Development

# Generator Interconnection Network Upgrades and CAISO 2024/25 TPP Reliability and Policy-Driven Projects

a) **Please provide an update on projects at or greater than 1MW that are interconnecting to SCE's electric transmission system. Please identify the updates to those included in the January 2025 CAISO Transmission Development Forum (TDF).**
   - The TPR & TDF does not address individual generation interconnection project status concerns. The scope of the projects included in the TPR forum are for projects previously approved through the CAISO Transmission Planning Process (TPP) and Network Upgrades identified in the generator interconnection process. The TDF does not provide updates on individual generation projects at or greater than 1 MW that are interconnecting to SCE's electric transmission system.

b) **Please identify the type and amounts (MW and MWh) of generation that will interconnect to the electric grid.**
   - The TPR & TDF does not identify the type and amounts (MW and MWh) of generation that will interconnect to the electric grid

c) **Please include in the discussion cost estimates and in-service dates as provided in the CAISO Transmission Plan approving each project, the previous TPR Project Spreadsheets, and the current estimates. Please provide the reasons for changes in costs or in-service dates.**
   - The CAISO Transmission Plan does not provide cost estimates and in-service dates of generation projects. CAISO 2024-2025 TPP Projects are listed on the next slide

# CAISO TPP Reliability and Policy-Driven Projects Through CAISO 2024-2025 TPP

## c) CAISO 2024-2025 TPP Projects in December 2025 TPR

| Project Name | 2024-2025 TPP | | Dec. 2025 TPR | |
|---|---|---|---|---|
| | Initial Estimated Cost | Initial Expected In-Service Date | Current Projected Total or Actual Final Cost | Current Expected In-Service Date |
| Serrano 500 kV SCD Mitigation | $183 M | 12/31/2029 | $68 M | 10/21/2033 |
| Serrano 230 kV SCD GIS Bus Split | $28 M | 12/31/2029 | $28 M | 10/21/2033 |
| Tortilla 115 kV Capacitor Replacement | $5M | 6/30/2029 | Not in December 2025 TPR Submittal. Expected to be included in June 2026 Submittal. | |
| Julian Hinds-Mirage 230 kV Advanced Reconductor | $76M | 4/01/2030 | Not in December 2025 TPR Submittal. Expected to be included in June 2026 Submittal. | |
| Alamitos 230 kV SCD Upgrade | $5M | 12/31/2032 | Not in December 2025 TPR Submittal. Expected to be included in June 2026 Submittal. | |
| Kramer-Coolwater 115 kV Line Loop-In to Tortilla 115 kV Sub | $37 M | 6/30/2034 | Not in December 2025 TPR Submittal. Expected to be included in June 2026 Submittal. | |

# 14. Remedial Action Schemes

Fernando Benavides, Senior Advisor – Integrated Major Project Development

# Remedial Action Schemes

**Please explain SCE's use, implementation, and governance of Remedial Action Schemes (RAS), including Centralized Remedial Action Schemes (CRAS), across the TPR Process portfolio, including:**

**a) the system conditions, contingencies, or interconnection-driven needs that trigger the use of RAS or CRAS solutions instead of (or in advance of) traditional transmission upgrades**

- Remedial Action Schemes ("RAS") are used to protect against adverse system conditions that can lead to thermal overloads, transient instability, and/or voltage collapse, etc. RAS's will trip generation following transmission system outages that are responsible for these adverse impacts. These adverse system conditions are caused by transmission outages which include transmission lines and/or transformer banks in conjunction with system conditions at the time of the outage (i.e., Generation output along with loading demand). The use of a RAS has been traditionally proposed and used as an alternative to more costly transmission upgrades when applicable.

**b) the functional purpose, operating logic, and scope of each referenced RAS/CRAS project (including but not limited to Lugo–Victorville RAS, Lugo–Victorville Centralized RAS, Tehachapi/Windhub/South of Vincent RAS, Calcite CRAS, and Windhub-related RAS), and how these schemes differ from or interact with one another**

- The functional purpose of a RAS is to trip generation that is responsible for adverse system conditions as explained in part (a) so to maintain system reliability within defined standards and criteria. At a high level, the operating logic works by assessing real time system conditions which include monitoring transmission line and/or transformer bank loading in addition to generator output. Based on predetermined system conditions and equations, the RAS will operate by tripping the necessary amount of generation to mitigate against adverse impacts. Each of the specific RAS's mentioned in the question operates in the same way. The only difference between each RAS is the generators that they each trip and the outages that they are responsible for monitoring. Each can be thought of as protecting a specific geographic region/location.

# Remedial Action Schemes

**c) the planning and study basis for implementing RAS/CRAS, including references to CAISO transmission planning studies, interconnection studies, or other analyses supporting their necessity**

- The requirement to implement and/or modify a RAS is completed through the generation interconnection studies in accordance with the CAISO GIDAP. Any supporting documentation would be available in those studies which are not public. Once a RAS has been approved, it is then included in the ATRA and TPP.

**d) how RAS/CRAS projects are coordinated with dependent transmission, substation, or generation interconnection projects, including whether RAS/CRAS facilities are required to be in service prior to or concurrent with those projects**

- The dependency and/or timing of a RAS is continuously assessed on a yearly basis as part of the generation interconnection studies in accordance with the GIDAP. If the generation that was found to trigger the need for a RAS is delayed, the RAS wouldn't be required until that generation materialized. If a RAS was found to be delayed and wouldn't be completed in time to include a certain generation interconnection project as a participant for tripping, that project would request a study from the CAISO to determine if they would be able to commence generating power or not.

# Remedial Action Schemes

**e) the reliability role of RAS/CRAS as interim versus long-term solutions, including any risks, limitations, or mitigation measures if underlying transmission reinforcements are delayed**

- RAS's are proposed as long-term solutions and are not interim.

**f) how SCE evaluates the continued need for, effectiveness of, and eventual retirement or modification of RAS/CRAS as system conditions evolve.**

- As part of the CAISO GIDAP and the ATRA, SCE continuously evaluates the need for the RAS's on the system. In most situations, there are only modifications to the RAS's to include new generation and to account for system topology changes. Because of the amount of generation on the system, the need for RAS's continues even with proposed transmission upgrades.

# 26. Incentives Received on Projects Related to Tehachapi Renewable Transmission Project (TRTP)

Fernando Benavides, Senior Advisor, Integrated Major Project Development

# Incentives Received on Projects Related to TRTP

**Please provide an overview of the following projects, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the projects in the past 12 months. Please include in the discussion any notable risks or challenges to this program.**

**Please also explain whether any of the following projects are receiving FERC-approved rate incentives, and if so what are the incentives?**

- **SP-29, Northern CRAS to Tehachapi CRAS**
- **SP-101, Tehachapi Renewable Transmission Project (TRTP) - Segment 11 System Upgrades: New Mesa-Vincent T/L (Via Gould) 500/230 kV**
- **SP-196, Tehachapi, Windhub, and New South of Vincent CRAS - tripping infrastructure**

# Incentives Received on Projects Related to TRTP

- SP-29 and SP-196 are not related to projects that qualify for incentives. SP-101 is labeled as an incentive project in the TPR but that is because there is residual spend from Segment 11 of the Tehachapi Renewable Transmission Project. However, the majority of those incentives which were related to construction restoration costs, were reversed from capital to O&M spend in 2022.

- As discussed in Meeting Topic 14 (Remedial Action Schemes), the primary purpose of the CRAS is to protect against adverse system conditions following outage events within the transmission system by tripping generation. Each of the specific CRAS's mentioned in SP-29 and SP-196 serve the same function in that they each are meant to trip generation following specific outages to prevent adverse system conditions.

- For each of the CRAS's, the project drivers included the development of generation which were responsible for and/or contributed to these adverse system impacts. Generation projects that were found to be responsible for triggering the need for the CRAS were assigned the scope and cost to implement as part of the generation interconnection process under the CAISO GIDAP.

# Incentives Received on Projects Related to TRTP

- The Tehachapi CRAS is currently operational in that it actively includes monitored outages for which existing generation is tripped when needed. The CRAS is currently going through planned updates which will include additional outages to be monitored for the purpose of protecting against identified thermal overloads in addition to the inclusion of additional generation to be added to the CRAS for tripping purposes. The current completion date to include these new outages will be by the end of December 2026.

- The South of Vincent (SOV) CRAS will protect against thermal overloads on the Lugo-Vincent No.1 & No.2 230kV Transmission Lines (T/Ls). The current completion date is tentatively set for the end of 2027 which has been primarily driven by the schedule for other projects that must get completed first including the Lugo-Victorville 500kV T/L Upgrade. The overall project risk would be to the schedule if there happens to be a delay with any of the transmission upgrades ahead in the queue. If those upgrades get delayed this would have an impact on the overall schedule possibly pushing the completion date beyond 2027.

# Incentives Received on Projects Related to TRTP

- The tripping infrastructure that is referred to is associated with the equipment related to the CRAS operation and related infrastructure that each generator has the responsibility for installing on their side of the Point of Change Ownership. The tripping infrastructure is required for SCE to physically trip a generation project which is accomplished by opening circuit breakers at the customer facility. Similarly, SCE will place the associated tripping infrastructure on its side of the POCO the funding of which is paid for by the Interconnection Customer. SCE's schedule for adding each generation project on its respective CRAS is also dependent on the IC's individual schedule and design which can and does change over time based on their own drivers that are outside of SCE's control which can include delays to their generating facility.

- The budget related to the tripping infrastructure is determined as part of the generation interconnection studies in accordance with the GIDAP. Please refer to the data included within the line-item SP-196 for the budget original and projected cost.

# 5. Allowance for Funds Used During Construction (AFUDC)

Joanna Jacobs, Sr. Manager – General Accounting

Jeremy Califano, Interim Principal Manager, T&S Project Management - Programs

# Placing Projects on Hold - Overview

**In SCE's TPR Process Stakeholder Meeting deck (August 28, 2024), it describes two processes it uses to suspend AFUDC, an Automatic System Process and a Manual Process. Please provide an update on how these two processes are used, including controls and monitoring procedures in place to identify projects placed on hold and the primary trigger for suspending AFUDC.**

- **No updates to process since August 2024 presentation**
- **<u>See Cycle 4 CPUC Data Request #1-03</u>**
  - Please see SCE's December 23, 2022 response to the CPUC's protest in the TO2023 Formula Rate Annual Update under ER19-1553 for a further process explanation and examples
- SCE currently has two processes to suspend AFUDC (i.e., turn off)
  - Automatic system process
    - AFUDC accrual for inactive work orders (i.e., work orders that have no direct recorded spend for >= 6 months) will be automatically turned off by PowerPlan and will accrue when direct charges are applied to the work order again
    - Categories of direct spend are Labor, Materials, Contract, and Other ("LMCO")
  - Manual process
    - Per the Project deferral/hold process (next slide), SCE Organizational Unit ("OU") reviews projects that will be placed in deferred status and will reach out to Plant Accounting to manually turn off AFUDC accrual in PowerPlan until which time the OU directs Plant Accounting to change back to active status

# Placing Projects on Hold – Manual Process

- Manual process for determining whether a project should be placed on hold or released from hold
  - SCE Transmission & Substation Project Management (TSPM, formerly MPO) reviews projects and shares deferral/on-hold status with Plant Accounting teams on a monthly basis
  - This review identifies projects that are deferred & placed on hold, as well as deferred projects that are subsequently moved back to active status
  - TSPM project managers are tasked with notifying Plant Accounting of any additional projects to be placed on hold, after which Plant Accounting will manually turn off AFUDC until such time it is moved back to active status
  - SCE Project Controls also updates project-specific on hold status in SAP, as well as in P6 (project scheduling system)

# Placing Projects on Hold – Manual Process (Cont)

**Primary triggers for placing a project On Hold and suspending AFUDC**

- TSPM's general criteria defines project on hold as inactivity for at least 3 months with minimal charges (under $10K) for that period and at least an 80% confidence level that project will continue in future
  - In final decision, project managers exercise judgment based on their knowledge of the project(s) in question
- Other triggers can include the following:
  - Project gets placed On Hold due to capital budget and/or regulatory constraints (e.g., approved budget is lower than expected, thereby causing projects to be deferred to future years)
  - Project gets placed On Hold due to reprioritization of system and/or business needs (e.g., Project A needs to take higher priority than Project B, thereby deferring Project B to future year)
  - Project gets placed On Hold due to reduction in load growth demand (e.g., this scenario applies specifically to load growth projects like DSP/TSP programs)

# 13. Transmission Conductors

Brian Powell, Senior Engineer 2, Transmission Engineering

# Transmission Conductors / Reconductors

**a) Please describe SCE's use of various types of transmission conductor in past projects and current projects, as well as any plans to employ new types of transmission conductor in future projects. Please describe any recent, current, or future pilot projects.**

- In the past, SCE has used copper, aluminum, and aluminum reinforced conductors among others. SCE has used ACSR (aluminum conductor, steel reinforced) conductor and has piloted and installed advanced conductor technologies such as ACSS (aluminum conductor steel supported), and composite supported conductors such as ACCR (aluminum conductor carbon reinforced) and ACCC (aluminum conductor carbon core). SCE is standardizing ACSS and ACCC as the conductor options for future projects. There are no active pilot projects for transmission conductor but SCE is always considering opportunities.

**b) Please discuss SCE’s current process and criteria for selecting the appropriate conductor for transmission projects.**

- For a circuit that requires an electrical upgrade/reconductor, SCE will evaluate and iterate different conductor types to meet the electrical objectives and creates the least number of structure replacements required. SCE will evaluate the effects of conductor loading on structures (i.e., conductor tensions to meet clearance requirements, diameter, and weight) and compare that to the existing structures’ capabilities.

**c) Please describe criteria that SCE uses to assess cost-effectiveness of transmission conductor and what ratepayer benefits different types of conductors provide.**

- During the execution phase, an evaluation is done and a cost estimate is performed to quantify different scope elements that have been considered. SCE will balance the total cost, timeline, and risks associated with project elements to deliver the objective for the project on time and within budget.

# Transmission Conductors / Reconductors

**d) If SCE uses an external design/engineering firm for a transmission design project, explain whether SCE or the external firm is responsible for determining the conductor to be used.**

- Generally, SCE will leverage external engineering contractors to develop transmission deigns for projects. The SCE team drives the decision process of selection of conductor types while the engineering contractor is there to design the scope elements based on the SCE project team's input.

**e) Please provide the conductor manufacturers from which SCE procures conductor for recent, current, and future projects.**

- For ACSR and ACSS, SCE utilizes Southwire. For ACCR, SCE has used 3M in the past and for ACCC SCE uses Taihan, Lamifil, and Prysmian

**f) Please describe all transmission outages resulting from conductor failure in the past 12 months, including the reasons for the conductor failure.**

- There were 9 outages resulting from conductor failure. Causes include storm damage, aircraft strike, vandalism, and parted conductor.

**g) Please explain the criteria used to determine the need for tower raising on reconductoring projects.**

- The decision to raise towers during reconductoring projects is made on a case-by-case basis. Typically, tower raising is evaluated as a design option when replacing a structure would result in excessive costs, scheduling challenges, or significant environmental impacts. Additionally, if reconductoring a section does not offer a clear advantage over the overall impact of raising the tower, then a tower raise may be considered instead.

# Lunch – 30 minutes

# 9. Data Centers

Oscar Marroquin, Senior Advisor, CIMOS/ Rule 2

# Data Centers

**Has SCE received any applications for transmission-level interconnections for data center projects? If so, please describe the details of the planned project(s), including but not limited to cost, timeline, and rate schedule. If not, please describe how SCE plans to treat such an interconnection application in the future. Discuss whether SCE has seen or anticipates congestion impacts from data center loads in neighboring utility territories.**

- SCE has received 5 transmission level applications of which only one moved forward with the study for Transmission service. The Study was completed and the customer has been provided the results. The customer has not moved forward with formally requesting Transmission service for the project.

- Requests which require a transmission voltage are provided in accordance with SCE’s Rule 2.B and 2.H.
  - The process is captured through the Method of Service (MOS) Study analyzing transmission system impacts, technical requirements, estimated costs, and schedule for the installation of any equipment required to serve the new load

- SCE has not observed congestion impacts on its system resulting from data center load growth in neighboring utility service territories. Transmission Planning primarily evaluates internal load growth and generation interconnections; potential inter-utility impacts are addressed through CAISO's TPP and Affected System Study procedures where applicable. SCE will continue monitoring regional load trends through CAISO coordination.

# 10. Transmission-Level Electric Vehicle Charging

Oscar Marroquin, Senior Advisor, CIMOS/ Rule 2

# Transmission-Level Electric Vehicle Charging

**Has SCE received any applications for transmission-level interconnections for electric vehicle charging projects? If so, please describe the details of the planned project(s), including but not limited to cost, timeline, and rate schedule. If not, please describe how SCE plans to treat such an interconnection application in the future.**

- SCE has not received any applications of this type. Should SCE receive such an application, it will conduct a study for transmission service and discuss the results with the applicant.

- Requests which require a transmission voltage are provided in accordance with SCE's Rule 2.B and 2.H.
    - The process is captured through the Method of Service (MOS) Study analyzing transmission system impacts, technical requirements, estimated costs, and schedule for the installation of any equipment required to serve the new load

3. AACE Class – Project Cost Estimate Maturity (Field #48)

Peter Tran, Project Controls & Central Coordination, Manager, Cost Estimating

Jack Huang, Senior Manager, Estimating & Project Cost Development

# Data Field 48, AACE Class

**Please provide an update on how SCE assigns, updates, and governs AACE cost estimate classifications across the full project lifecycle, including**
**a) the methodology and criteria used to assign an initial AACE Class**
**b) whether, how, and at what project milestones AACE Classes are reviewed and updated as projects progress from planning through construction and near completion**
**c) the quality control, oversight, and correction mechanisms used to ensure AACE Class designations are accurate, consistent, and current**
**d) the status of SCE's implementation of AACE classifications since the August 28, 2025 TPR Process Stakeholder Meeting, including any policies, tools, training, interim measures, or explanations for delay**
**e) SCE's plans, timeline, and any system or process upgrades to fully integrate AACE Class reporting across all TPR Process projects; and**
**f) the benefits SCE anticipates from adopting AACE classifications and the challenges or obstacles it foresees, including how SCE plans to mitigate those challenges.**

# How SCE Assigns Estimate Class

- Project estimates Class are assigned at the time of estimation at certain control points (e.g., gating process). An estimator decides an AACE Class by approximating the location of the project in its lifecycle, reviewing the level of engineering, and use of their professional judgement to assign an estimate Class.
  - AACE class is not reassessed due to forecast changes that may occur in-between gates
- Assigned estimate Class is an attribute that is reviewed at the conclusion of the estimating task by the Cost Estimating Manager
- Please reference SCE's prior responses to **Cycle 3 CPUC Data Request Q2-17** and **Cycle 4 CPUC Data Request Q2-55** for a walkthrough and training on how estimate Class are assigned
  - The criteria and process to assign Class remain consistent. No upgrades are planned.
- The practice to assign an estimate Class allow users of the estimate to approximate location in its project lifecycle and level of engineering at the time of estimation. Users may reference established AACE guides to understand accuracy range for the project at the time it was estimated.

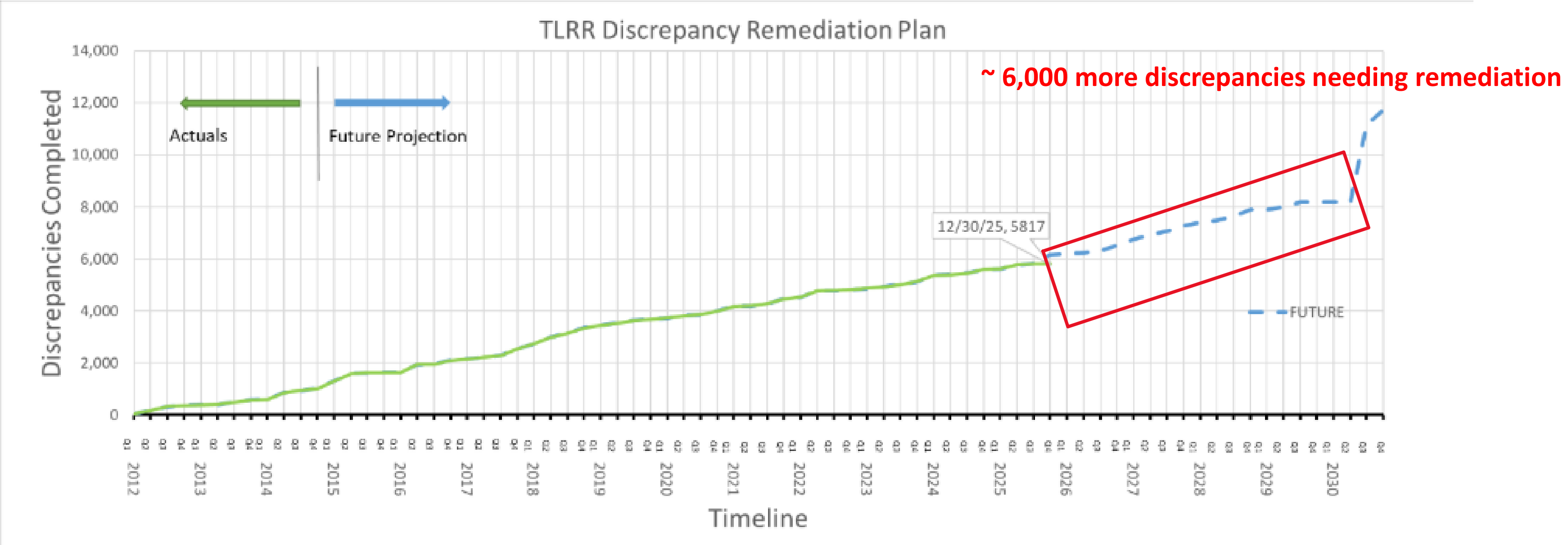
# 12. Transmission Line Rating Remediation (TLRR)

Blake Wheatley, Engineering Senior Manager, Transmission Project Development

# Transmission Line Rating Remediation (TLRR)

**Please provide an update on the total number of discrepancies that have been addressed and the total number of discrepancies still needing remediation for all TLRR work.**

| | Total |
|---|---|
| Cleared by Other Project/Program | 783 |
| Cleared by Radial Re-rating | 217 |
| Cleared (No Violation) | 1,132 |
| Construction Complete (Remediated) | 3,685 |
| **TOTAL COMPLETED/CLEARED** | 5,817 |



# Transmission Line Rating Remediation (TLRR)

## Cost Comparison – June 2025 to December 2025

| Project ID | Project Name | June 2025 TPR | December 2025 TPR | Change ($K) |
|---|---|---|---|---|
| PB-22.56 | Big Creek 3-Rector No.2 TLRR Remediation | $ 15,147 | $ 17,856 | $ 2,709 |
| PB-22.45 | Eagle Mountain-Blythe TLRR Remediation | $ 85,018 | $ 84,868 | $ (150) |
| SP-26 | Control-Silver Peak TLRR Remediation | $ 255,831 | $ 328,488 | $ 72,657 |
| PB-22.40 | Big Creek 3-Rector No.1 TLRR Remediation | $ 89,624 | $ 89,925 | $ 301 |
| SP-23 | Eldorado-Pisgah-Lugo TLRR Remediation | $ 238,235 | $ 245,736 | $ 7,501 |
| PB-22.23 | Bailey-Pardee TLRR Remediation | $ 23,780 | $ 23,780 | $ (0) |
| SP-25 | Ivanpah-Control TLRR Remediation | $ 1,040,679 | $ 1,043,899 | $ 3,220 |
| **Sum of Total Change >$1M** | | | | **$ 86,239** |

# 8. Physical and Cyber Security-Related Projects

Earl Lee Hall, Senior Advisor, Corporate Security

# Physical and Cyber Security-Related Projects

**Please describe the scope of SCE's non-confidential security-related transmission projects, including both physical and cybersecurity programs. Please provide an update on major projects in this category, their current status, and any significant risks or challenges.**

- **See Cycle 4 CPUC Data Request #2-16**

- The following slide presents a table summarizing SCE's security-related transmission programs included in the December TPR submission. It outlines each program's scope, key activities, current status, and primary challenges.

- SCE's physical security transmission programs focus on hardening critical transmission assets and do not incorporate cybersecurity components. While individual projects may encounter schedule, sourcing, or implementation challenges, lessons learned are applied across the program portfolio to improve future project execution and mitigate recurring risks.

# Security Programs' Summary

| Program Name | Row ID | Programmatic Overview | Major Projects / Initiatives | Current Status | Potential Challenges |
|---|---|---|---|---|---|
| Critical Infrastructure Protection | PB-21 | Physical security access controls to meet NERC CIP V5 compliance requirements (high & medium impact sites) | NERC CIP v5 | Completed | N/A |
| Physical Security Enhancements | PB-30 | Physical security upgrades at Tier 1 sites in compliance with NERC CIP-14 | NERC CIP 014 | Completed | N/A |
| NERC CIP V6 Physical Security Access | PB-31 | Physical security access controls to meet NERC CIP 006 V6 compliance requirements (low impact sites) | NERC CIP v6 | Completed | N/A |
| Grid Infrastructure Protection Program | PB-32 | Physical security upgrades at non-Tier 1 critical sites | Tier Program General Security Upgrade | On Track (2035 – Ongoing) | Scope Changes<br>Construction Delays<br>Permitting Issues<br>Environmental |
| Substation Security Upgrades | PB-39 | Special fences around Tier 4 transmission facilities | Metal Abatement | On Track (Ongoing) | |
| NERC CIP Physical Security Project (NERC CIP 014) | PB-45 | Physical Security upgrades at Tier 1 sites in compliance with NERC CIP-14 | NERC CIP 014 | Completed | N/A |
| Substation Perimeter Security Upgrade | PB-46 | Physical security upgrades at non-Tier 1 critical sites | Tier Program General Security Upgrade | On Track (2035 – Ongoing) | Scope Changes<br>Construction Delays<br>Permitting Issues<br>Environmental |

# 15. Wildfire Impacts

## Antonio Ocegueda, Principal Manager, FERC Rates & Tariffs

# Wildfire Impacts

**Please provide an update on whether any SCE transmission facilities were affected by the January 2025 wildfires in SCE territory and, if so, provide a list of impacted transmission lines, towers, poles, and substations, along with estimated cost to repair damages.**

- While investigations are ongoing, SCE is currently not aware of any damage to SCE transmission facilities or lines related to the January 2025 wildfires in SCE's service territory

# 19. PB-14.06 Etiwanda Substation: SA3 Hybrid Solutions

Michael O'Brien, Sr. Project Manager, Major Construction

# PB-14.06 Etiwanda Substation: SA3 Hybrid Solutions

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program.**

- **Drivers:** To provide up to date protection automation of substation equipment
- **Timeline:** Planned completion by end of 2028
- **Scope:** The scope of this project is to upgrade the substation automation to current standard, known as "SA3", which involves replacement of all the protection relays with newer micro-processor relays
- **Status:** This project completed design and will be receiving the 100+ relay racks in the coming months. Relay racks will then be staged in the MEER building and work will begin to wire them up, test and confirm all equipment, then "cut-over" the protection from the old relays to the new, and finally remove all the old equipment.
- **Risks:** The main risk on this project is schedule related, due to the large number of relay racks to be replaced in an existing MEER, and the amount of issues and as-built drawings that can come up when re-wiring an entire MEER
- **Budget:** The current total project budget is $12.8M
- **Dependencies:** There are a number of "satellite" substations at the other ends of the circuits which require individual relay upgrades as well. There are also many projects in the queue at Etiwanda substation, that have been scheduled after this project is finished, which are entirely dependent on this work being completed.
- **Changes:** Changes were made to the overall budget and schedule last year, upon material confirmation and construction sequencing. There was also a small change to the wiring design due to a change in the protection scheme for the 220kV Transformer setup.

# Break – 10 minutes

# 20. PB-18 Substation Transformer Bank Replacement Program

Erminda Kamphuis, Strategic Planning, Senior Advisor, Substation Project Development

# PB-18 Substation Transformer Bank Replacement Program

a) **Approximately how many transformer banks on SCE's system are currently categorized as "very poor" or "poor" condition (or an equivalent highest risk rating)? Provide a rough number or range (e.g., "on the order of 10–15 banks system-wide").**
   - There are no FERC-jurisdictional transformer banks that are rated at "poor" or "very poor" conditions

b) **Identify a few of the highest-priority transformers that remain in service and are being monitored due to very poor or poor condition. For example, name one or two substations and bank IDs that are considered top candidates for replacement in the near future based on their condition and risk. If specific identities cannot be disclosed, at least indicate the general locations or system areas of these top-priority units.**
   - There are no FERC-jurisdictional transformer banks that are rated at "poor" or "very poor" conditions

c) **Explain whether SCE plans to replace all transformers currently rated as "very poor" or "poor" within the next four-year cycle. If not all can be addressed that soon, clarify how SCE is prioritizing among them and the timeframe (e.g., "the highest-risk 50% of very poor/poor units are targeted by 2028, with the remainder by 2030" or similar.**
   - Currently there are no FERC-jurisdictional transformers rated at "poor" or "very poor" conditions

# 30. SP-168 Vista–Etiwanda 230 kV 1 Line Upgrade

Cyrus Mirabueno, Associate Project Manager, Transmission & Substation Project Management

# SP-168 Vista–Etiwanda 230 kV 1 Line Upgrade

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program. Explain why the cost estimate for the Vista–Etiwanda 230 kV Line Upgrade project increased by roughly $53 million (about an 80% rise) between the June 2025 and December 2025 TPR Process cycles.**

**Driver**: Approved as a Policy Driven Project by CAISO per 2022-2023 TPP to prioritize the development of several transmission projects that will help meet California's clean energy policies, particularly to enable the delivery of many new renewable generation projects and relieve constraints on the existing grid

**Timeline**: CAISO need-date of December 2031. Currently, forecasted construction completion of 2027

**Status**: The project is completing final engineering, preparing to order long lead material, and planning for submitting all required environmental and agency permit applications in 2026. Another important effort this year is construction planning and strategy.

**Risks**: Outage availability in the general area are restricted to winter season and coordination with multiple ongoing projects with the same outage needs could significantly delay construction completion. Internal construction resources might be decreased due to conflicting priorities, which could further delay completion. The project will require avoiding warning zones for the Delhi Sands Flower Loving Fly, a federally endangered insect. Finally, risk involves delay in acquiring permits from external agency e.g., Caltrans.

# SP-168 Vista–Etiwanda 230 kV 1 Line Upgrade

**Budget**: The current total project budget is $66.1M. The increase of the budget was due to the previous budget ($13M) serving as an initial placeholder, reflecting only anticipated transmission-related direct expenses. The change in cost was due to changes in transmission design and construction methods. The current project budget is also comprehensive, accounting for environmental and permitting expenses, departmental overhead, anticipated risks, and contingency allocations.

**Dependencies**: The project dependencies for the Etiwanda-Vista 230kV Line Upgrade include timely delivery of the ACCC wire and acquisition of all required permits from various external agencies and municipalities to ensure SCE meets the forecasted start date of construction

**Changes**: The most significant change to the project in the past 12 months is the increase in the project budget. Notably, the transmission design scope changed due to adjacent project design (Etiwanda-San Bernardino 230 kV Line Upgrade – reconductor with ACCC wire. Proceeding with this project's tower raises may result in damage to new line) with the need to increase rating to address future load growth in region and construction sequencing.

See Cycle 4 CPUC Data Request 2-36 for further information

# 21. SP-01 Calcite Substation

Hamid Arshadi, Project Manager, Transmission & Substation Project Management

# SP-01 Calcite Substation

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program and an explanation of factors leading to the recently-announced 23-month delay.**

- **See Cycle 4 CPUC Data Request #2-18**

# SP 01 – Calcite Substation Construction

## Project Background:

- **Calcite Substation** (formerly known as Jasper Substation) is a proposed 220 kV switching station, to be located near Lucerne Valley in San Bernardino County, CA
- This project is intended to strengthen the local electrical grid infrastructure and facilitate the integration of renewable energy sources. It plays a critical role in advancing California's commitment to expanding its clean energy portfolio, focusing on sustainable and reliable energy supply
- Through the Generation Interconnection Process, Avantus, the customer for the following interconnection projects requested interconnection into the proposed Calcite 220 kV Substation:
    - **Sienna Solar 1:** a 200 MW solar PV project, and
    - **Sienna Solar 2:** a 55 MW solar PV/BESS project

## Calcite Substation Scope:

- Construction of the new Calcite 220 kV substation
- Loop in of the Lugo-Pisgah No.1 220 kV Transmission Line into the new Calcite substation
- Construction of SCE portion(s) of Sienna Solar 1 & 2 gen-ties line into the substation
- Construction of associated distribution and telecommunication work

## Project Budget:

- Current project cost estimate is approximately $97,336 million , as reported in the recent CPUC Data Request.

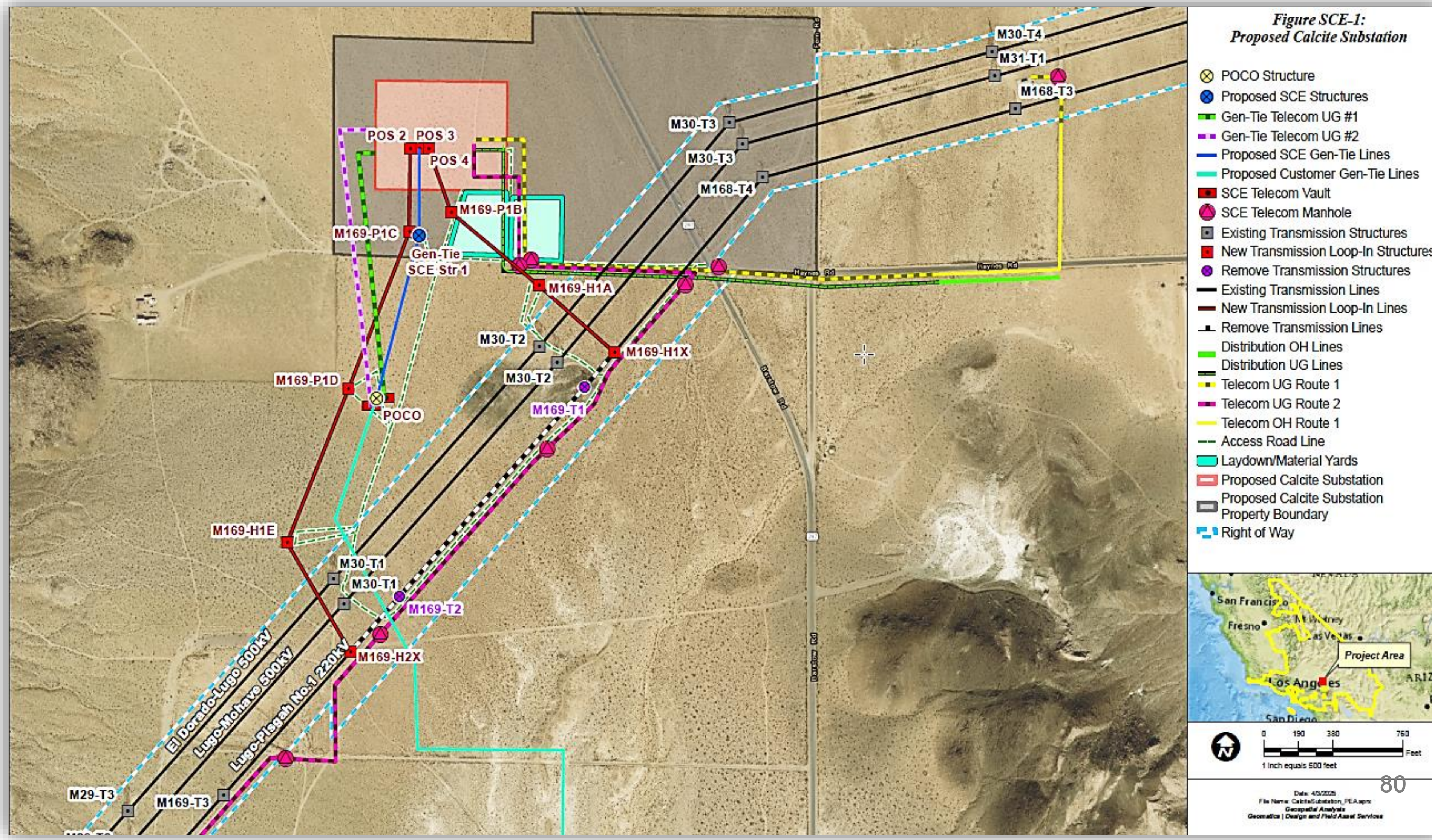
## Regulatory Approval Update:

- The 23-month delay in processing these projects was primarily due to the interconnection customer's CEQA review and permitting responsibilities under the County of San Bernardino as the CEQA lead agency.
- On January 27, 2026, San Bernardino County Board of Supervisors upheld the Planning Commission's decision by: 1) Approving the Interconnection Customer (Avantus) Sienna Solar 1 and Sienna Solar 2 Projects' Conditional Use Permit; and 2) Certifying the Environmental Impact Report (EIR) for the Sienna Solar 1 and Sienna Solar 2 Projects, which also includes and covers the SCE Calcite Substation's environmental analysis.

## Notable Risks & Construction Schedule:

- Based on recent developments, the overall project risk is now considered low.
- Calcite Substation construction to start in Q1 2027. Forecasted Operating Date in December 2028.

# Calcite Substation Components



# 31. SP-169 San Bernardino–Etiwanda 230 kV 1 Line Upgrade

Hamid Arshadi, Project Manager, Transmission & Substation Project Management

# SP-169 San Bernardino–Etiwanda 230 kV 1 Line Upgrade

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program. Explain the factors contributing to the approximately $30 million (31%) increase in the cost estimate for the San Bernardino–Etiwanda 230 kV Line Upgrade between the June 2025 and December 2025 TPR Process cycles.**

**Driver**: CAISO Policy Driven Project per 2022-2023 TPP to prioritize the development of several transmission projects, particularly the deliverability constraints needed to support development of many new renewable generation projects

**Timeline**:

- Design/Engineering Completion: May 2026
- Major Material Delivery: 2027-2029
- Construction Start: October 2028
- Construction Completion: December 2031

**Status**: The project team is in process of performing & completing final engineering design, followed by ordering long lead material, and planning for submitting all required environmental and agency permit applications in 2027-2028. Another important effort this year is construction planning and strategy.

**Risks**: The project generally runs adjacent to High Fire Risk Area (HFRA). Outage availability in the general area are restricted to off hot-season and coordination with multiple ongoing projects with the same outage needs could notably delay construction completion as planned. Internal construction resources might be decreased due to conflicting priorities, which could further delay completion. The project will require avoiding warning zones for the Delhi Sands Flower Loving Fly, a federally endangered insect. Finally, risk involves delay in acquiring permits from external agency e.g., Caltrans, BNSF, local municipalities.

# SP-169 San Bernardino–Etiwanda 230 kV 1 Line Upgrade

**Budget**: The current total project budget is $94.5M. The increase of the budget was due to the previous budget ($65.1M) serving as an initial placeholder, reflecting only anticipated transmission-related direct expenses. The change in cost was due to changes in transmission design and construction methods. The current project budget is also comprehensive, accounting for environmental and permitting expenses, departmental overhead, anticipated risks, and contingency allocations.

**Dependencies**: The project dependencies for the San Bernardino-Etiwanda 230kV Line Upgrade include timely delivery of the ACCC wire/conductors and acquisition of all required permits from various external agencies and municipalities to ensure SCE meets the forecasted start date of construction.

**Changes**: As noted in the response to the Cycle 4 CPUC Data Request 2-37, the most significant change to the project in the past 12 months is the increase in the project budget. Notably, the major components that impacted existing or added to the project cost included:

- changes to engineering design scope of work,
- added costs due to increased construction method (e.g. helicopter use and crossing existing 66kV lines),
- permitting (Caltrans, railroad, water treatment facility),
- environmental costs,
- added known risks and contingency.

These new components were determined and calculated during the cost aggregation effort completed after June 2025.

# 22. SP-04 Alberhill Substation Loop In

Michael Bass, Sr. Project Manager - Transmission, Substation Project Management

# SP-04 Alberhill Substation Loop In

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program.**

# Overview and Status Update on the Components of the Alberhill Project (SP-04)

**Purpose of Project**

- Due to increased load in Western Riverside County, SCE has proposed the Alberhill System to power 5 existing distribution substations, previously powered by the Valley Substation
- When the Alberhill System is complete, SCE will create additional capacity at Valley and activate tie-lines between the Alberhill and Valley systems resulting in greater system capacity, increased reliability and greater resilience as well as opening of additional operating capacity for connection of future renewable energy projects and storage projects to the SCE grid

**Scope and Budget**

- 3.5 mi of new 500 kV Transmission Line with 12 new towers to loop-in existing Serrano-Valley Transmission Line
- New 1,120 MVA 500/115 kV Substation, 24-acre property near Temescal Canyon Rd. / 15 Fwy
- 20 mi of new double circuit 115kV lines to connect satellite distribution substations, 11 mi of dist. circuits
- 5 mi of new Telecom fiber optic circuit and microwave communication system
- 5 new access roads, 3 helicopter landing pads for access to new Transmission towers
- No scope changes last 12 months
- $472.4M nominal FERC-$199.2M CPUC $273.3M

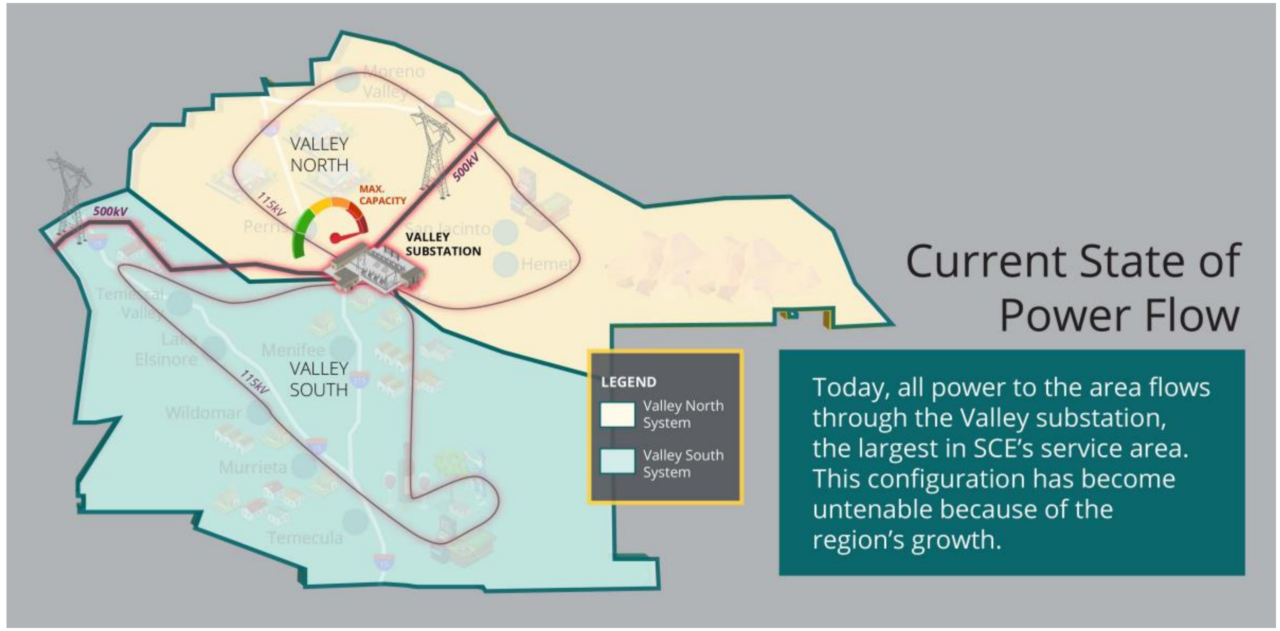
**Project Status/Regulatory Update**

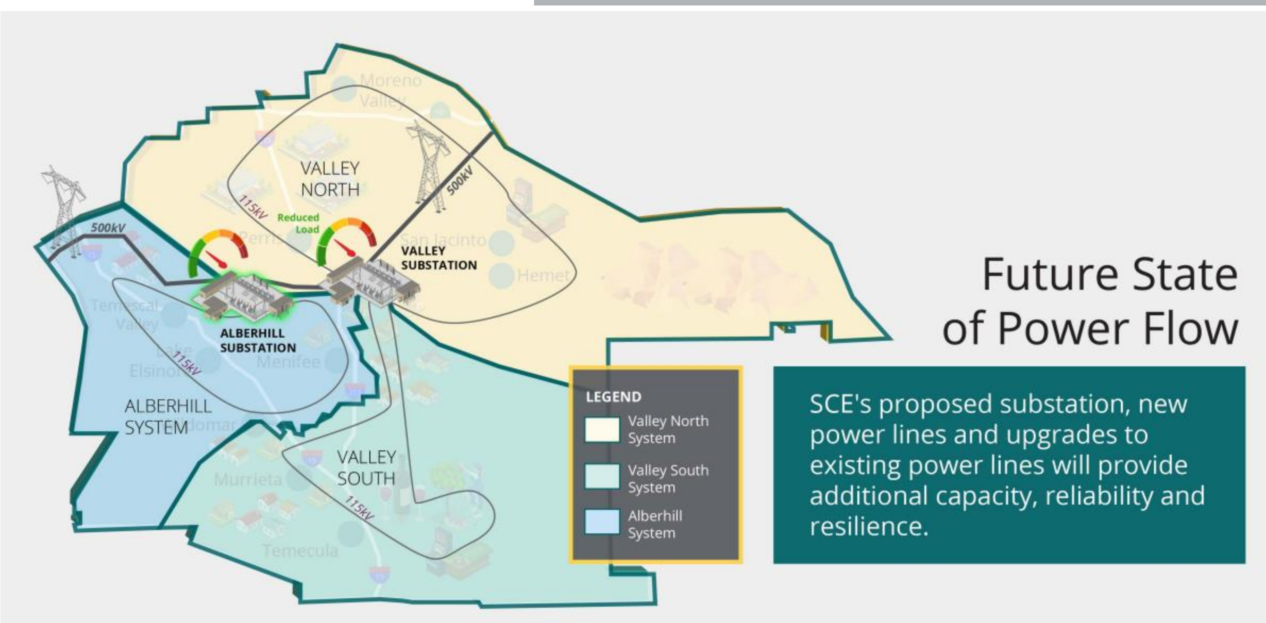
- SCE filed a third amended CPCN application June 2, 2023
- Addendum to the Final EIR issued June 2024
- ***Proposed Decision received February 2026, Final Decision expected March 2026***
- SCE has launched final engineering and major materials (transformers, circuit breakers) procurement to expedite energization of the project
- Bids for linear scope expected March 2026
- Construction scheduled to start 3Q 2026
- Substation and 500kV lines to be energized by June 2029

**Project Risks**

- Schedule - Environmental Permitting, completion of engineering and right-of-way acquisition
- Budget – Bids to be received from linear scope EPC and substation construction contractor have the potential to exceed forecast

# SP-04 Alberhill – Current vs Future



# 24. SP-24 Cerritos Channel Tower Relocation

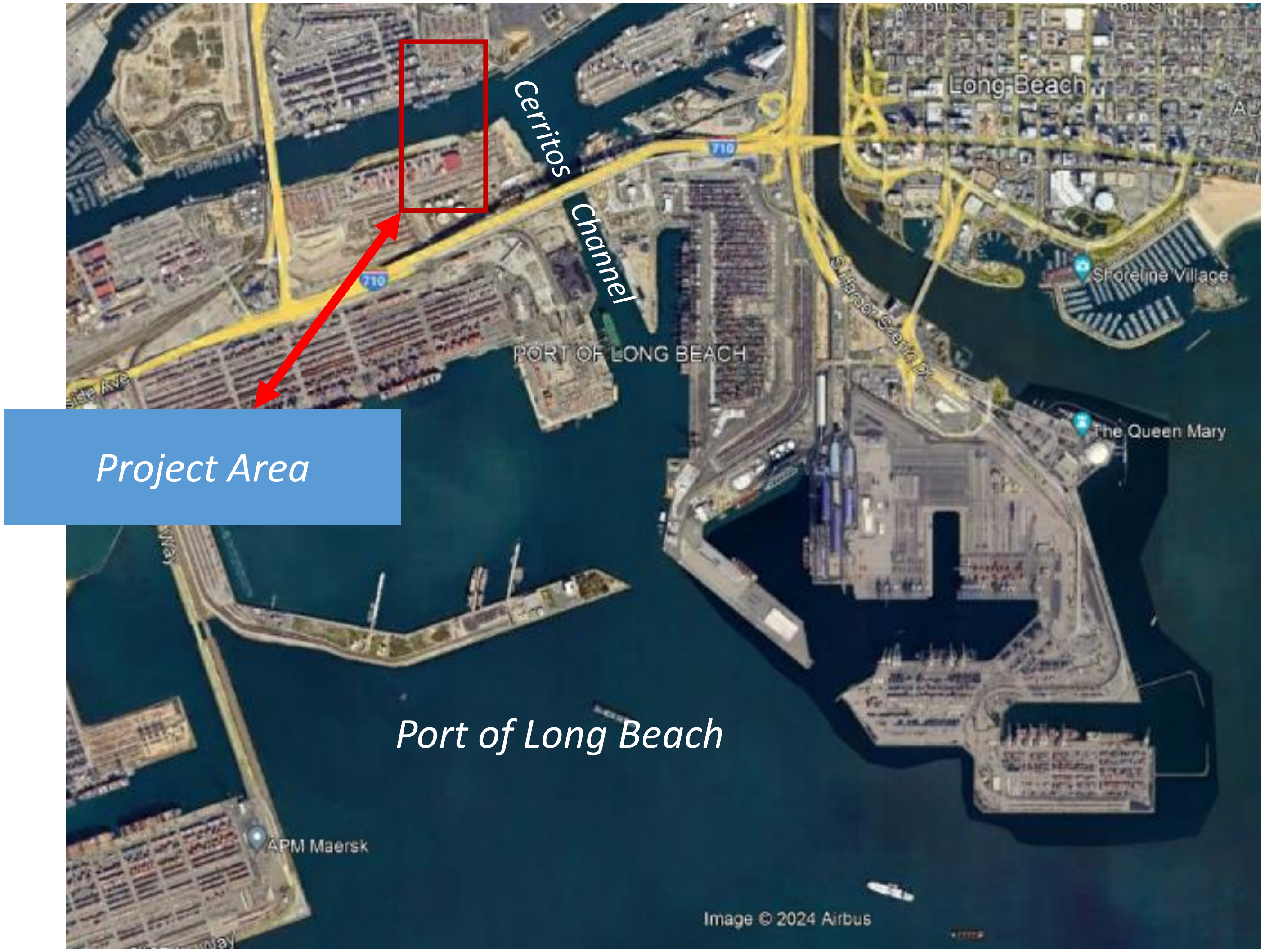
Michael Bass, Sr. Project Manager - Transmission, Substation Project Management

# SP-24 Cerritos Channel Tower Relocation

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program.**

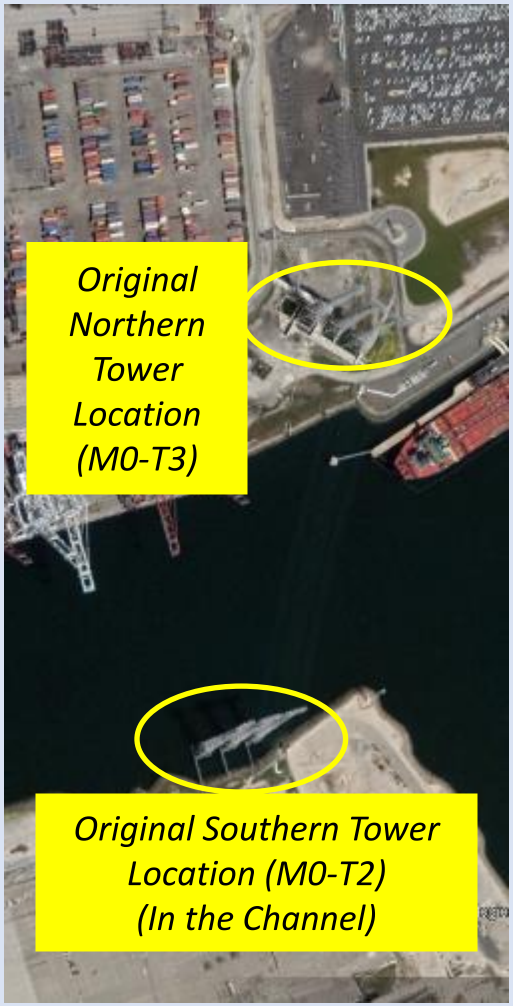
- **Project Drivers** - Remove four existing, idle tower foundations from underwater in Cerritos Channel. Benefits are facilitating POLB ability to dredge the channel to facilitate ship traffic. Previous work to replace previous shorter transmission tower with higher towers and energization of new lines has been completed
- **Timelines** -
  - RFP Issuance: March 2026
  - Bid Due: July 2026
  - PO Issuance: February 2027
  - Construction Start: July 2027
  - Construction Finish: July 2029
- **Current Status** - An RFP will be issued March 2026 to solicit contractor to perform the foundation removal work
- **Risks** – 1) Receiving sufficient bid response to issue contract for removal work, 2) geotechnical risk (instability of pier), 3) previous unknown underwater pipeline identified, 4) release of fuel or hydraulic fluid from construction equipment during foundation removal
- **Project Budget** is $85M for this Phase 2 scope; $51M FERC, $34M CPUC. Per 2018 FRM budget approval.
- **Changes past 12 months** – Project scope has not changed. During the previous 12 months, SCE issued an RFP to complete the work. Only one acceptable bid was received and SCE determined that additional vendors should be identified and a rebid would be conducted.

# Project Location



# Original and Current Configuration

*Original Configuration (as of 2017)*




*Current Configuration (as of 2026)*


*Remnants of Original M0-T2 Tower*

# 23. SP-10 Riverside Transmission Reliability Project

Kenneth Spear, Sr. Project Manager – Transmission, Substation Project Management

# SP-10 Riverside Transmission Reliability Project

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program. Explain the approximately $142 million (19%) increase in RTRP's cost estimate between the June 2025 and December 2025 TPR Process cycles.**

- **Project Driver (reason):** Request from Riverside Public Utilities for load growth and reliability
- **Current Status:** Under construction. Began work on underground portion in June 2025
- **Milestones to completion:**
  - **Underground Construction**
    - Vista circuit Construction start: June 2025, Completion: Dec 2026
    - The Vista 220kV UG circuit civil construction has surpassed 50% completion.
    - The Mira Loma 220kV UG circuit civil construction started in Feb 2026 and construction forecast completion: Sep 2027
  - **Cable system installation forecast:** Jan 2027 thru March 2028
  - **Overhead construction**
    - **Start forecast:** March / April 2026
    - **Completion forecast:** Oct 2027
  - **Substation construction**
    - **Start forecast:** Oct 2027
    - **Completion forecast:** Oct 2029
  - **Project commissioning/completion**: **Forecast: Q4 2029**
- **Project Risks/Challenges**
  - Ongoing public opposition to overhead segment of project
  - Delays by RPU on completion of their Substation (Wilderness) may result in preventing the 220kV circuits from being energized
  - Weather delays and Environmental Seasonal restrictions
  - Equipment and Material delays due to unforeseen international restrictions (Cable)
  - Delays due to archaeological or cultural findings

# SP-10 Riverside Transmission Reliability Project

- **Project Budget:** $756,039,050

- **Project Dependencies:**
  - RTRP is dependent on collaboration with the City of Riverside Public Utilities Substation
  - Fiber Optic connectivity by SCE and RPU is a key element to test relay systems
  - RTRP depends on collaboration with local jurisdictions to support encroachment permits, traffic control permits, and other local permits

- **Project changes in last 12 months:**
  - As an outcome of final engineering, two sets of vault clusters were deemed unnecessary and deleted from the alignment
  - These were known as splice vault clusters #13 on both the Mira Loma-Wildlife and Vista-Wildlife circuits
  - Splice vault sizes were also reduced in length to 16ft. Minor duct bank realignments have also taken place but construction disturbance areas remain the same.

- **Explain Cost delta of $142M between TPR Process cycles of June 2025 and December 2025.**
  - The change in costs was the result of a revision in the scope (deeper duct banks, larger foundation, more civil works on undeveloped substation land and off-site improvements), additional real property costs for the routing of the line, adjustments for the impacts of inflation from the date of the estimate to the current time (years later).

# Break – 10 minutes

# 25. SP-26 Control–Silver Peak TLRR Remediation

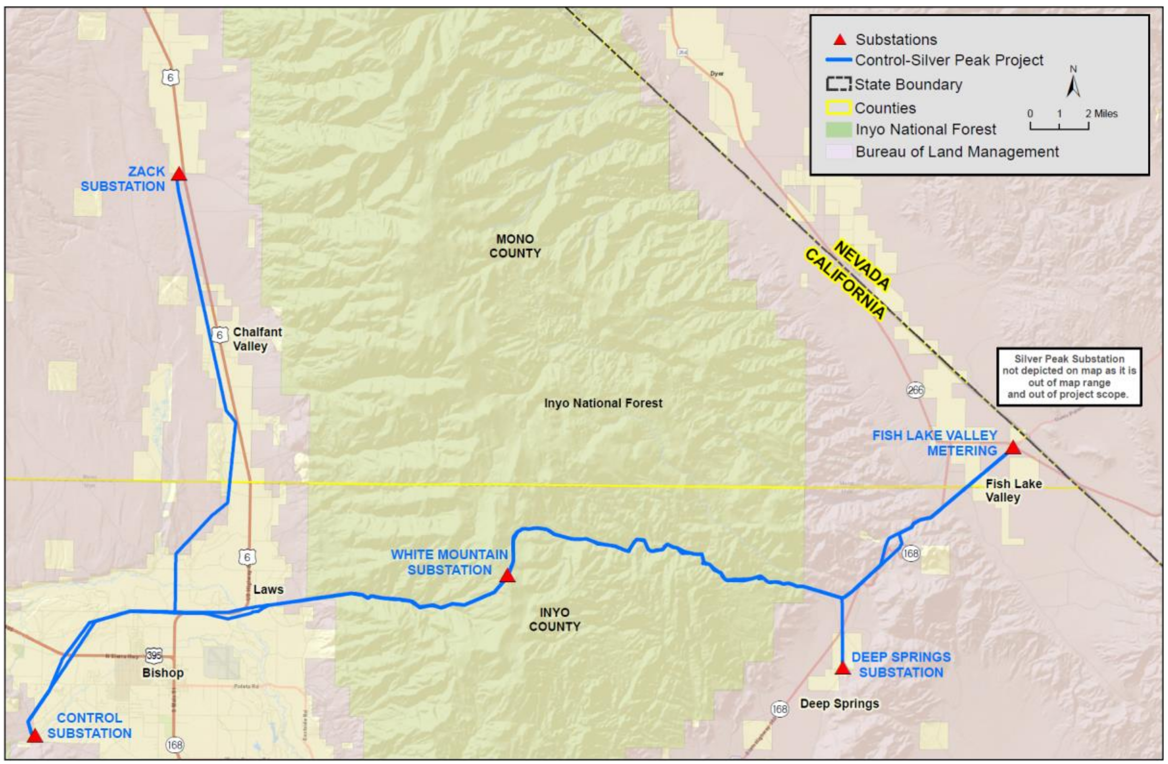
Marco Orozco, Project Manager – Transmission, Substation Project Management

# SP-26 Control–Silver Peak TLRR Remediation

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months.**

**Driver and Project Overview**: The Transmission Line Rating Remediation (TLRR): Control-Silver Peak 55kV Subtransmission Project is a compliance-driven initiative that spans approximately 61 circuit miles and is focused on ensuring adherence to the California Public Utilities Commission's (CPUC) General Order 95 clearance requirements and the North American Electric Reliability Corporation (NERC) Facility Ratings. The project is located in northern Inyo and southern Mono counties near the city of Bishop, and the Chalfant Valley, Fish Lake Valley, and Deep Springs areas.

To achieve compliance, the project will implement various remediation strategies throughout the circuits including full rebuild of certain segments (e.g., replacement of all existing poles/tower and conductor with completely new materials), while only requiring targeted pole replacements in the other segments.




**Status & Timeline**: SCE filed CEQA and NEPA applications with the CPUC and the BLM in 2021. If approved by the agencies, the project currently anticipates to begin construction in 2028 and project completion in 2031.

**Budget**: Current Project Budget is ~ $328M

**Risks**: See next slide

**Project Dependencies**: Regulatory approval

**Project Changes in the Past 12 Months**: None

# SP-26 Control–Silver Peak TLRR Remediation

**Please include in the discussion any notable risks or challenges to this program.**

- **Sensitive Environmental Areas** - The project alignment cross several sensitive environmental areas including Bi-State Sage Grouse habitat, Bighorn Sheep habitat, and culturally sensitive areas requiring extensive environmental review and mitigation planning

- **Seasonal Restrictions -** Because construction occurs in high-altitude and environmentally sensitive areas, certain activities may be limited or prohibited during specific seasons to protect wildlife and prevent environmental impacts. These restrictions, combined with potential for heavy winter conditions, would limit site access and shorten the workable construction window, which may significantly constrain the overall construction schedule.

- **Restoration** – Restoration efforts will be challenging because vegetation in the White Mountains, rising to elevations near 10,000 feet, grows slowly and has limited natural recovery capacity.

- **Difficult Terrain for Construction -** Large portions of the transmission corridor traverse the White Mountains and steep canyon regions (e.g., Silver and Wyman Canyons), making construction access, equipment transport, and structure replacement significantly more challenging

**Explain the factors that led to approximately a $73 million (22%) increase in the cost estimate for the Control–Silver Peak TLRR Remediation project between the June 2025 and December 2025 TPR Process cycles.**

- The increase in the cost estimate between the June 2025 and December 2025 TPR submittals is primarily due to the vintage of the underlying cost basis and the extended duration of the project's regulatory phase. The June 2025 TPR was built on a 2021 cost estimate, which became increasingly outdated as the project progressed more slowly than anticipated through regulatory reviews and the planned timeline was deferred multiple times. For the December 2025 cycle, the project team added the escalation and inflation factors to the prior estimate using S&P Global Intelligence escalation rates.

17. PB-05 Substation Unplanned Capital Maintenance and PB-06 Substation Planned Maintenance Program

Mark Christensen, Manager – Apparatus and Maintenance Field Support

# PB-06 Substation Maintenance Program

**Please describe these programs and provide an update on major projects under each. Please include in the discussion any notable risks or challenges to the programs.**

**<u>SCE's Planned (Preventative) Capital Maintenance Program PB-06</u>**
**Planned (Preventative) Substation Capital Maintenance Program Description**

- Proactive, condition-based capital equipment or component replacements for asset life extension on capital assets with no future replacement plans
- Reduces costs associated with in-service failure caused replacements and forced outages
- Uses asset health data to help prioritize work in a controlled manner and avoid emergent forced outages
- Programmatic approach that allows SCE to proactively plan capital maintenance repair work over a controlled schedule, perform any necessary engineering design activity, and allocate and manage resources effectively
- Reduces failure risk and improves grid performance through proactive replacement and monitoring technologies for efficient asset replacement
- Targets replacing substation equipment and ancillary systems that are required for proper Substation operation and are nearing or surpassing the end of service life, have degraded equipment health condition, or have reached obsolescence

**Examples of Recent Projects**

- Proactive replacement of Transmission Class Bushing Terminal Insulators reaching E.O.L.
- Proactive replacement of Transmission Class CB main+arcing contacts reaching E.O.L.
- Proactive replacement of Transmission Class CB mechanism for life extension

**Program Risks or Challenges**

- Lead time on capital components for transformers and circuit breakers

# PB-05 Substation Unplanned Capital Maintenance

**Please describe these programs and provide an update on major projects under each. Please include in the discussion any notable risks or challenges to the programs.**

**<u>SCE's Unplanned (Reactive) Capital Maintenance Program PB-05</u>**

**Unplanned (Reactive) Substation Capital Maintenance Program Description**

- Addresses urgent, unplanned failures: Focuses on rapid replacement of failed substation equipment when unexpected events threaten safety, reliability, or service continuity
- Drivers for these emergent projects can include deteriorating equipment conditions, weather events, such as lightning strikes, or faults because of animal intrusion, resulting in equipment damage or component failure
- Enables fast restoration and risk mitigation: Uses timely, like-for-like replacements to restore normal operations, minimize outage duration, and avoid escalating safety or operational risks
- Must be completed in a timely manner because substation equipment failures may lead to prolonged outages, unsafe operating conditions, or more costly reactive solutions
- Inherently variable and unpredictable: Program costs fluctuate year to year due to the nature of reactive events, requiring flexible planning and reliance on historical experience rather than fixed schedules

**Examples of Recent Projects**

- Devers Sub – 2AA Bank 220kV Bus Disconnect Failure
- Antelope Sub – Replacement of failed 1AA Bank Tertiary Reactor R11

**Program Risks or Challenges**

- Unplanned failures cause unpredictable costs and workloads
- Emergency parts procurement and complex coordination are needed amid supply chain strains
- Emergent outages complicate system reliability planning and can increase impact risks

# 28. SP-152 New Coolwater A 115/230 kV Bank

Rodney Preijers, Senior Project Manager, Transmission and Substation Project Management

Silvia Montes, Senior Project Manager, Transmission and Substation Project Management

# SP-152 New Coolwater A 115/230 kV Bank

**Please provide an overview of the project, including any project drivers, timelines to completion, current status, project risks, budget, project dependencies, and changes to the project in the past 12 months. Please include in the discussion any notable risks or challenges to this program. Explain what caused the estimated cost for the New Coolwater A 115/230 kV Bank project to increase by roughly $39 million (45%) from June 2025 to December 2025.**

- The project consists of the installation of one 230/115kV transformer, one 220kV position, one 115kV position, and one MEER

- The project need is to address system reliability concerns

- The project is currently on hold. SCE is waiting for draft TPP results in March 2026 and final TPP results in May 2026

- Cost increase $39M – To capture additional scope and outdated unit cost estimates. Schedule drivers primarily due to scope complexity (temporary line configurations, rights checks, grading requirements), sequencing with other work at the substation, and change in the initial A Bank build out that triggered significant engineering rework and cost re-estimation

# 29. SP-154 North of SONGS – Serrano 500 kV Line Project (Competitive Project)

Alex Gutierrez, Sr. Project Manager, TSPM

# SP-154 North of SONGS – Serrano 500 kV Line Project (Competitive Project)

**Please provide a comprehensive update on the schedule, cost, contractual status, and reliability implications of the SP-154 North of SONGS – Serrano 500 kV Line Project, including the associated Serrano 4AA 500/230 kV Bank and 230 kV GIS rebuild, addressing the following:**

**a) Competitive contracting strategy and status**

**b) APSA status and interim project governance**

**c) Integrated project schedule and milestones**

**d) Incumbent Scope Schedule**

**e) Schedule delay explanation**

**f) Material procurement impacts**

**g) Outage coordination constraints**

**h) Cost estimate reconciliation and justification**

**i) Reliability impacts and interim mitigation**

# Project Overview: North of SONGS-Serrano 500 kV Project General Bid Routing Assumptions

- New approximately 30 mile* single circuit 500 kV Transmission Line connecting SCE's Serrano Substation to a new substation located near SONGS
    - Segment 1
        - New ROW
    - Segment 2
        - Utilization of existing ROW
    - Segment 3
        - Utilization of existing ROW
- SCE is currently preparing CEQA documentation; application filing expected Q4, 2026


*Project length and proposed route is considered preliminary and under development. Ultimate project location will depend on several factors, including the ultimate location of the new Recon substation, as well as CEQA and other regulatory processes, etc.

# North of SONGS – Serrano 500 kV Line Project
# Project Status

- Cost  $292M (in 2023 constant dollars)
- SCE is working diligently with CAISO to execute the project's Approved Project Sponsor Agreement (APSA)
    - It is premature to provide comprehensive updates to the schedule, cost, and reliability implications at this time
- The project's construction contracting strategy will have several considerations that may be affected by the CPUC's licensing process, including the determination of a final project scope, transmission line routing and design
    - SCE will likely select a competitive contracting strategy at or near the conclusion of the CEQA process and issuance of a final decision by the CPUC in the licensing proceeding
- Current milestone estimate:
    - APSA execution Q1, 2026
    - CPCN Application submittal Q3, 2026
    - CPCN decision Q1, 2029
    - Material procurement Q1, 2029
    - Construction Q4, 2029
    - Project energization Q2, 2032
- See TPR Cycle 4 Data Request #29 for further information

# Close Out & Next Steps

Antonio Ocegueda, Principal Manager
FERC Rates and Tariffs

# Close Out & Next Steps

- Stakeholders to submit comments to ferccaseadmin@sce.com

    [Please cc: Jerry Huerta (jerry.huerta@sce.com) and Mark Khouzam (mark.Khouzam@sce.com)]

- Stakeholder questions and/or comments are to be submitted by **March 16**
    - SCE will respond to questions within 15 business days of receipt

- Project-specific follow-up questions and/or comments are to be submitted by **April 13**
    - SCE will respond to questions within 10 business days of receipt

- Stakeholders may provide comments to SCE by **April 30**

- Next TPR submission to occur on **June 1, 2026**