CPUC Comments on Southern California Edison's Transmission Project Review Process (Cycle 1) October 31, 2024

Background

The Transmission Project Review (TPR) Process is a California Public Utilities Commission (CPUC) stakeholder process, with the goal to provide stakeholders with timely and useful information on recent historic, current, and projected FERC-jurisdictional transmission capital projects and spending.

On June 2, 2024, Southern California Edison (SCE) provided Stakeholders in the TPR Process a spreadsheet of transmission projects (TPR Project Spreadsheet or PS) pursuant to CPUC Resolution E-5252, which established the TPR Process, effective January 1, 2024.

The TPR Project Spreadsheet includes individual projects and programs with FERC-jurisdictional transmission spending over $1 million. Approximately 427 projects and programs were included. In addition to the TPR Project Spreadsheet, SCE provided 722 additional authorization documents related to specific projects. These documents include presentation decks and meeting minutes, as well as work initiation forms and project summaries. SCE also provided nine procedure documents with information related to the processes by which it identifies, proposes, authorizes, plans, prioritizes, budgets, and implements large projects.

Data Quality

The CPUC notes that the data provided by SCE was generally clear and accurate, save for some areas of the PS that prompted clarification from SCE, such as Data Field 1 (Row/Line No.) and Data Fields 26-28 (Utility Unique IDs #1-3). Information was provided and broken out, in accordance with the requirements of E-5252. In addition, communications from the utility were timely and clear.

The CPUC acknowledges and appreciates the June 2024 TPR Project Spreadsheet submittal, and with the expected corrections the CPUC sent to SCE on Monday, October 21, 2024, the improved data will make the review of SCE's submittal more efficient and improve communications.

Data Request Responses

During this TPR cycle, the CPUC submitted five sets of data requests to SCE (four public and one confidential set), including 99 individual questions. All responses to the TPR data requests were received by the CPUC, and SCE's responses were generally timely and complete, with proper notification being provided for any delays. Follow-up questions centered mostly on seeking greater detail rather than following up on insufficient responses.

Stakeholder Meeting

SCE held a Stakeholder Meeting on August 28, 2024, to respond to questions from Stakeholders on the TPR Project Spreadsheet. During this meeting there was extensive discussion of several overarching topics, as well as specific programs and projects, including:

- Placing Projects on Hold,

- SCE TPR Process Data Sheet,
- Transmission Planning Process and Other Previously Approved Projects,
- PB 20-Phasor Measurement System Install,
- SP 01 - Calcite Substation Construction,
- SP 10 Riverside Transmission Reliability Project,
- DesertXpress Rail Project Updates,
- PB 06 and Others - Tracking Spending for Blanket Programs,
- TLRR Project Statuses,
- SP 25-Ivanpah Control TLRR Remediation Project,
- CPUC Filing Type and Filing Date (Fields 43 and 44),
- Cancelled Projects,
- SP 101-Tehachapi Renewable Transmission Project (TRTP),
- Generator Interconnection-related Network Upgrades, and
- Transmission Vs. Distribution Voltage Levels (Determination of CAISO Control Criteria).

Concerns with SCE's Projects and Processes

Based on the CPUC's review of the project information submitted by SCE, the Stakeholder Meeting presentation, and responses to the CPUC's data requests, the CPUC has some concerns and observations with individual initiatives, detailed below.

Ongoing Concern with Calcite Substation

The Calcite Substation project (located on the same site as the former Jasper Switching Substation) is located in San Bernardino County and has been under development for over 13 years. The Jasper Switching Substation was just one of six components of the South of Kramer project, which received incentive ratemaking treatment in a 2011 FERC Declaratory Order (134 FERC ¶61,181). In that order, the South of Kramer project included numerous upgrades in Southern California designed to increase access to the transmission grid for new renewable generation in the area. FERC approved a 100% abandoned plant incentive for these projects, as well as the Construction Work-in-Progress (CWIP) incentive, which was intended to allow SCE's inclusion of the costs of the South of Kramer Project in rate base before that project was used and useful.

In 2013, SCE submitted Application 13-08-023 at the CPUC for a Certificate of Public Convenience and Necessity (CPCN) for the South of Kramer Project (a.k.a. the Coolwater-Lugo project). The CPCN for that project was dismissed without prejudice by the CPUC in 2015 (Decision 15-05-040).

Despite the dismissal of the application for the South of Kramer project, there was still a need for the substation component to interconnect generation at the earlier Jasper Switching Substation location. According to data responses, SCE calls this the "second primary component of South of Kramer," now renamed Calcite. According to SCE, through the Generation Interconnection Process, only the following interconnection customers have requested interconnection into the proposed Calcite 220 kV Substation and have an executed Large Generator Interconnection Agreement (LGIA):

- Avantus' Sienna 200 MW solar farm and 55 MW Battery Energy Storage System (BESS) project located on private land and
- Aurora Solar, LLC's Stagecoach 200 MW solar and 200 MW BESS project, located on California State Lands Commission."[1]

Based on its review of the project and documentation, the CPUC has identified three issues with the Calcite interconnection project: 1. the cost of the project, 2. lack of cancellation for the South of Kramer project, and 3. the appropriateness of applying the South of Kramer incentive ratemaking to the single Calcite Substation component.

The current Calcite project has little resemblance to the South of Kramer project that FERC found eligible for incentive ratemaking in 2011. While Calcite is a substation at the same location as the original Jasper Switching Substation, Calcite is not part of the original larger set of projects designed to increase transmission capacity in Southern California. SCE's description of the South of Kramer project[2] included construction of approximately 65-75 miles of new high-voltage transmission lines, new substation construction, two substation upgrades, and construction of approximately 35 miles of new telecommunications cable. That was substantially different than the current substation design. Per recent data responses, the current Calcite Substation design includes: one new substation, 5,000 feet of new transmission lines, 3,800 feet of distribution lines, a generation tie line connection, and a small amount of telecommunication fiber.[3] In short, the current scope of Calcite is simply an interconnection substation, similar to many other proposed substations on the grid designed to interconnect generation.

CPUC makes the following recommendations regarding the South of Kramer and Calcite projects:

- SCE should formally abandon the South of Kramer project and seek abandoned plant treatment of the $4.582 million of historical costs that are not attributable to the current Calcite project. These costs should be amortized expeditiously and not included in capital additions related to the Calcite project.
- As the current Calcite project is not the South of Kramer project that FERC found eligible for CWIP incentive ratemaking in 2011, costs related to the Calcite project should not be eligible for the Abandoned Plant or CWIP Incentives.
- Costs associated with the development of interconnection for the Stagecoach and Sienna solar projects should be recovered consistent with the costs for other generator interconnections in the CAISO's Generator Interconnection and Deliverability Allocation Procedures (GIDAP) process. There is no distinguishable difference between these projects and others in the CAISO GIDAP.

Projects Proceeding Under Letter Agreement

SCE has nine interconnection projects proceeding with a Letter Agreement rather than a fully executed LGIA. Ordinarily, and by the CAISO tariff, interconnection projects should have signed

[1] Information Request Response CPUC - SCE- TO2025- 001-04, September 3, 2024
[2] https://www.sce.com/about-us/reliability/upgrading-transmission/kramer
[3] Data Request Response ED-SCE-Public-Cycle 1-004-02, October 3, 2024

a generator interconnection agreement (GIA) prior to proceeding with interconnection-related network upgrades or other interconnection-driven work. SCE maintains that these Letter Agreements will be replaced by GIAs before interconnection.[4] Concerns remain due to the differences between LGIA and Letter Agreements.

Upon review of the Letter Agreements furnished by SCE, it does appear that concerns such as financial security, risk of early withdrawal, construction schedule and insurance are addressed in the Letter Agreements. However, the letter agreements allow the customer to remain in the CAISO queue, which creates a logjam that could affect viable projects entering the queue in later clusters. In addition, projects that withdraw from the queue after signing an LGIA are required to forfeit a percentage of funds, which are retained by SCE and placed in a special account to fund network upgrades. Therefore, the LGIA process provides a clearer and more certain financial benefit to ratepayers.

The CPUC prefers interconnection projects follow the CAISO GIDAP procedures (detailed in Appendix A) and proceed under GIAs rather than Letter Agreements.

Process for Placing Projects on Hold/Excessive AFUDC Accruals

A longstanding concern of the CPUC is that SCE has maintained projects as "active" that should be placed on hold. The concern is that projects with little-to-no progress that are not formally placed on hold continue to accrue AFUDC and other overhead costs, resulting in higher project costs that are charged to ratepayers. This was discussed in detail in previous stakeholder review processes.

During the August 28, 2024 TPR Stakeholder Meeting, SCE was asked about its rationale for placing projects on hold and the associated mechanism for suspending/resuming AFUDC. SCE's processes were described as follows:[5]

Placing Projects on Hold

- There is no automatic mechanism for placing projects on hold; they are reviewed monthly, and the project manager is responsible for tasking Plant Accounting with turning a project off – or back on. As part of this task, Plant Accounting will manually turn off AFUDC when a project is turned off, and vice-versa when the project is turned on.

Suspending AFUDC

- There is an automatic process for suspending AFUDC on a project; the accounting software will turn off AFUDC if there is no "direct recorded spend" for greater than six months. AFUDC will resume when recording of direct charges begins again, or when Plant Accounting is notified per the above.

CPUC's comments on these processes are as follows:

- SCE's process for placing a project on hold is subject to the Project Manager's judgment and specific knowledge of the project. The CPUC has observed several projects that are

[4] Data Request Response ED-SCE-Public-Cycle 1-004-06, October 3, 2024
[5] SCE TPR Cycle 1 Stakeholder Review Meeting Presentation, pages 12-13. August 28, 2024

awaiting action from other parties or events (e.g., securing right-of-way, permitting, design changes, and weather-related delays)[6] to proceed. There is a wide range of uncertainty regarding when these actions will be completed, given that they are beyond SCE's control. The CPUC recommends that SCE standardizes a process so that projects are not considered active when there is no meaningful progress. Not doing so results in an unreasonable accrual of AFUDC by default, for longer than necessary.

- The criterion of zero direct expenses for six months seems to be a low automatic threshold for AFUDC suspension. The result is effectively no automatic AFUDC suspension process, as even one nominal dollar of expenditure on a project would result in AFUDC continuing to accrue, while there would be no meaningful corresponding project progress.

The CPUC will continue to use various review criteria (e.g., elapsed time since the start of construction, significant in-service date delays, and accrued AFUDC as a percentage of project cost) in subsequent cycles and follow-up with SCE with additional data requests on anomalous projects. Cycle 2 will present an opportunity to tabulate and compare AFUDC behavior as a function of time and project deferrals.

PB-43.05/43.06 – Pardee-Pastoria (San Joaquin and North Coast) Reconductor

The Pardee-Pastoria (San Joaquin and North Coast) are two separate blanket projects (i.e., PB-43.05 and PB-43.06, respectively) categorized under the larger PB-43: "Transmission Overhead Conductor Infrastructure Replacement" program. The stated purpose of PB-43 is "[p]roactive replacement of targeted overhead conductor sections."[7] Upon review of the projects' TPR Process information, the CPUC followed-up with Data Request 01-01 seeking more information on the disparity in per-mile costs between PB-43.05 ($2.020 million/mile) and PB-43.06 ($1.360 million/mile).

There appears to be conflicts between the information provided in the TPR Project Spreadsheet, the responses to data/information requests, and the Rate Year 2025 Draft Annual Update (AU) Schedule 16 Workpaper "ISO Cap Expenditures Non-Inc Projects" (WP16). WP16 lists the combined project cost for Pardee-Pastoria (San Joaquin and North Coast) as $61.150 million, and the response to the AU Information Request states this is solely for replacing failed and/or potentially failing conductors. In the most updated information provided in the TPR Project Spreadsheet, the combined project cost remains the same (i.e., $61.150 million), but states that the assets are 105+ years old, have an in-service date in 2025 (compared to the in-service date of 2021[8]) and include new "Ampjack tower raise" structures.[9]

Based on the lack of clarity of cost information for what appears to be overlapping scope, and the uncertainty of recovering costs from ratepayers, the CPUC continues to seek clarity on this project.

Riverside Transmission Reliability Project

[6] Data Request Responses ED-SCE-Public-Cycle 1-001-42 through 1-001-50, August 6, 2024
[7] SCE Transmission Project Review Cycle 1 Project Spreadsheet, June 2, 2024
[8] Information Request Response CPUC - SCE- TO2025-001-016, September 3, 2024
[9] Data Request Response ED-SCE-Public-Cycle 1-001-01, August 6, 2024

Per the June 2, 2024 TPR Project Spreadsheet and the August 28, 2024, TPR Stakeholder Meeting, the Riverside Transmission Reliability Project (RTRP) is currently active. The project, designed to provide additional reliability to Riverside Public Utilities, was approved by the CAISO in 2007, with CEQA approval by the CPUC in 2020. The project had an original expected operative date of 2009, which has now been pushed to December 2028, or possibly later. Per SCE staff during the August 28, 2024 Stakeholder Meeting, the project will likely exceed the $587 million cost included in the TPR Project Spreadsheet.

Per SCE's project discussion during the TPR Stakeholder meeting, the City of Riverside, which had delayed the project while investigating additional undergrounding options for a portion of the line, is currently in support of the proposed line configuration. SCE is currently in the development phase of the project, including real estate procurement and detailed line engineering.[10] However, SCE noted that the support for the current configuration could change under a different Riverside City Council, casting future uncertainty on the project.

The CPUC is concerned about the length and cost of delays on this project, and the potential uncertainty of further legal or local government action regarding this line. The project will be delayed by at least 20 years from its originally expected operative date, and the projected project costs have increased several-fold to $587 million included in the TPR Project Spreadsheet. SCE now estimates these costs are likely to increase further due to delays, even if there is no change to the project design. Delays to projects of this magnitude result not only in increased capital costs, but also in additional planning, engineering, and re-permitting if the project is not formally on hold.

The CPUC questions why transmission ratepayers throughout California should bear the costs of these delays. Further, there are potential impacts on system reliability. The reliability issue was identified 20 years ago as the driver for the project, and reliability concerns have only increased as Riverside has grown in the years since the issue was identified.

[10] SCE TPR Cycle 1 Stakeholder Review Meeting Presentation, pages 26-29. August 28, 2024

APPENDIX A – **Description of CAISO Grid Interconnection Procedures**

The current interconnection process, the Generator Interconnection and Deliverability Allocation Procedures (GIDAP), was instituted by the California Independent Systems Operator (CAISO) in 2009 and applies to projects entering the CAISO during the Clusters 1 through 14 (approximately 2009-2023). Projects entering the CAISO queue in Cluster 15 (late 2024) onward will be governed by the Resource Interconnection Standards process (RIS).

GIDAP Process

The GIDAP process consists of the following steps. GIDAP is under the tariff provisions of CAISO Appendix DD.[11]

1. The CAISO holds an open period for project developers to apply for connection to the grid. These open periods are generally 30 days in April. The project is validated by CAISO and Participating Transmission Operator (PTO) engineers, and the projects are given a "Q number" and placed in the CAISO Interconnection Queue. Documents required at this step include engineering documents, computer models, corporate information, site exclusivity, etc.
2. The Phase 1 Study commences after the projects are validated. The study takes about 10 months to complete. Upon completion, the study is presented to the Interconnection Customer (IC or customer). This is followed by a results meeting where the customer can ask questions and request certain changes. The customer must then decide to continue in the process or withdraw. To continue, the IC must make an interconnection financial security deposit with the PTO. Typically, this is a letter of credit in the amount of 15% of the estimated cost of upgrades and facilities necessary to connect.
3. The Phase 2 study begins for those who have made the initial financial security posting. Projects may park for a year if they are not ready to move forward. The Phase 2 study requires approximately 10 months. The Phase 2 study results are presented to the customer followed by a results meeting.
4. Customers wishing to continue in the process must increase their financial security posting to 30% and begin the process of negotiating a generation interconnection agreement.
5. After signing the generator interconnection agreement, the customer increases its financial security posting to 100% of the cost of the upgrades and facilities required for connection.
6. Construction of the interconnection facilities begins and is completed by an agreed-upon in-service date.
7. With construction complete, the customer then tests equipment, supervised by the PTO. When the tests are complete, the project begins operation and is registered in the CAISO grid operations system.

More details on CAISO website: https://www.caiso.com/generation-transmission/generation/generator-interconnection/interconnection-request-study

[11] https://www.caiso.com/Documents/AppendixDD-GeneratorInterconnectionDeliverabilityAllocationProcedures-asof-Sep26-2021.pdf

Renewable Interconnection Standards (RIS) Process

The following procedures will affect Cluster 15 and future interconnection Clusters. The RIS process reflects changes required in FERC order 2023 and follows the provisions of the CAISO compliance filing for the order approved by FERC in 2024[12]. RIS will be under the provisions of CAISO Appendix KK.[13]

There are substantial differences in the RIS process. It is designed to speed up the application, study, and contracting portion of the interconnection process. RIS is designed to reward generation projects that are ready to proceed, willing to make a financial commitment, and which have procured power purchase agreements with authorized off-takers.

1. CAISO will hold an open window for applications. The current "re-application" process for cluster 15 is open as of October 2024 and will close on December 2. The timeline for future cluster windows is still under development.
2. Participants are provided with information about the status of deliverability and facilities at each substation on the system. Projects are encouraged to select a point of interconnection that is available and has a possible deliverability allocation. Projects are scored by the CAISO to rank them with regard to completeness and location. Ties in the scoring are decided by auction.
3. Projects are validated for technical compliance. The interconnection request must contain documents showing corporate structure, site control, load flow, dynamic engineering models, and reactive power capability.
4. Customers must submit application and study fees along with a commercial readiness deposit. Projects proceeding under the merchant option will make a merchant option deposit.
5. CAISO will notify projects advancing to the technical validation phase.
6. CAISO will perform four studies: a) Cluster Study to identify facilities required for interconnection and deliverability; b) Reassessment Study to evaluate actions of other cluster participants, withdrawals, transmission upgrades that might affect the Cluster Study results; c) Interconnection Facilities Study to identify costs and time to complete upgrades required for each project; d) Deliverability Study to determine the deliverability allocation available to projects.
7. CAISO will host one scoping meeting per transmission zone prior to the beginning of the studies.
8. Following the completion of the studies, projects may begin to negotiate generation interconnection agreements and make final deposits necessary to initiate construction.
9. Construction of the interconnection facilities begins and is completed by an agreed upon in service date.
10. With construction complete, the customer then tests equipment, supervised by the PTO, and when the tests are complete the project begins operation and is registered in the CAISO grid operations system.

More detail on the CAISO website: https://www.caiso.com/documents/resource-interconnection-standards-fair-questions-and-answers.pdf
https://www.caiso.com/documents/resource-interconnection-standards-interconnection-study-timeline.xlsx

[12] https://www.caiso.com/library/may-16-2024-tariff-amendment-compliance-with-ferc-order-no-2023-er242042. May 16, 2024 Compliance Filing regarding FERC Order No. 2023 (ER24-2042).
[13] https://www.caiso.com/documents/ferc-order-and-ipe-2023-pending-iso-tariff-appendix-kk.pdf