2026 SB 1174 Assessment

ASSESSMENT OF RENEWABLE AND STORAGE RESOURCES DEPENDENT ON DELAYED TRANSMISSION PROJECTS

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California Public Utilities Commission

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Assessment Summary

Senate Bill (SB) 1174 (Hertzberg), Stats. 2022, ch. 229 requires electrical corporations that are Participating Transmission Owners (PTOs), including Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Deigo Gas & Electric (SDG&E), to submit annual data to the California Public Utilities Commission (CPUC) on transmission project delays and the associated impact on renewable generation and storage resources. Since 2020, Californians have brought online over 37 GW of new generation and storage to serve California load, which includes over 500 new California Independent System Operator (CAISO) resource identifiers (IDs). While this progress is extraordinary for its contribution to reliability and increasing the use of clean, greenhouse gas free electricity generation, the ability for future resources to interconnect when and where needed is critical to maintaining reliability with affordability while meeting the State's ambitious clean energy goals. This report focuses on how transmission delays impact generation and storage development because despite the progress to date, there is an urgent need to better understand and address the multitude of transmission project delays and their impacts on generation and storage development.

Prior to this year's assessment, the CPUC made numerous changes to the 2026 SB 1174 data request, based on lessons learned from previous assessments and feedback from stakeholders. This assessment benefits from improved data consistency and integrity, and CPUC staff will continue to refine the data collection and analysis process in the future.

Data covered in this year's assessment was submitted within 2026 Draft Renewables Portfolio Standard (RPS) Procurement Plans. CPUC staff analyzed the data to create this report's assessment, which identifies the magnitudes and reasons for transmission project delays, and impacts on renewable energy generation and storage resources (hereinafter referred to as "generation and storage resources") seeking interconnection. Some of the most significant 2026 assessment findings are:

- PG&E, SCE, and SDG&E reported 413 in-development transmission projects, 275 (66.6 percent) of which experienced a delay, relative to the original In-Service Dates (ISDs) proposed when these projects were first approved. The most common delay reasons reported were Bundling Dependencies (29), Vendor/Third Party Delays (20), and Project Design (70) for PG&E, SCE, and SDG&E, respectively. The utility was reported as the delay resolver for 67 percent of transmission project delays, and there was an overall median delay of 27.5 months (2.3 years) across all delays.
- PG&E (66) and SCE (61) reported that 127 of 292 (43.5 percent) renewable generation and storage resources, seeking interconnection in their service territories, are dependent on delayed transmission projects – totaling 30.6 GW of capacity. Most of the dependent resources in PG&E's territory are storage resources (4.05 GW). Half of delayed or at risk of being delayed resources for SCE are hybrid renewable generation plus storage resources (7.3 GW). SDG&E reported that no renewable or storage resources in their territory depend on delayed transmission projects.
- The majority of permitting related delays were attributed to interconnection customers, which implies that permitting delays are often related to the generation and storage permitting, and not just the transmission permitting and approvals. Additionally, for many delay reason/resolver combinations there were too few projects reported to estimate a reliable median delay time.

- Regarding mitigation efforts for transmission project delays in 2025, PG&E focused on procurement and supply chain management for long-lead time equipment. SCE centered on organizational restructuring, interconnection process reform, and digital tooling. SDG&E centered on project management structure, staffing and contractor readiness, and procurement strategy.
- Between 2025 and 2026 the total reported volume of generation and storage resources in interconnection queues grew from about 40.7 GW to 48.8 GW, while the volume dependent on delayed transmission projects grew more sharply, from roughly 21.8 GW to 30.6 GW. The volume of PG&E and SCE resources expected to be delayed behind delayed transmission projects also increased significantly. Some of this increase may be attributed to improved familiarity and consistency with reporting requirements in addition to the increase in volumes of delays.
- Top reasons for transmission project delays in 2025 and 2026 are largely consistent and include: Bundling Dependencies, Project Design, and Material/Procurement delays.

Background

SB 1174[1] requires electrical corporations that own transmission facilities to annually submit to the CPUC changes to in-service dates (ISDs) of transmission and interconnection facilities that will provide transmission deliverability to renewable energy generation and storage resources (hereinafter referred to as "generation and storage resources") that have executed interconnection agreements, and to identify the reason for any changes to the status of in-service dates. PG&E, SCE, and SDG&E are the three participating transmission owners (PTOs) that are required to report this data related to SB 1174.[2] The PTOs reported data on all transmission and interconnection projects in development and generation and storage resources, as well as any transmission and interconnection projects that were completed January 1, 2025, to December 31, 2025, and had experienced a delay from the original ISD, proposed when each project was first approved, within their 2026 Draft RPS Procurement Plans[3], as instructed per the CPUC March 27, 2026 Assigned Commissioner ruling (ACR)[4].

SB 1174 also requires that the CPUC provide a systemwide assessment of delays to eligible generation and storage resources based on the annual information provided by PTOs. This report includes the assessment as well as findings and recommendations to address the delays.

[1] https://legiscan.com/CA/text/SB1174/id/2605746.

[2] Non-electrical corporations (non-IOUs) that are participating transmission owners are not required to participate in the SB 1174 data collection process.

[3] Reported SB 174 data is available online; however some data may be redaction for confidentiality: https://www.cpuc.ca.gov/trackingenergy.

[4] See Assigned Commissioner ruling: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M603/K483/603483112.PDF.

Changes to the 2026 Assessment

To ensure the electrical corporations report common data, the CPUC sends a data request each year. CPUC staff made numerous changes to the 2026 SB 1174 data request, based on lessons learned from previous assessments and feedback from stakeholders. The most significant changes include:

- Changed the reporting period for completed, delayed transmission projects to only the previous calendar year (2025), compared to the previous 15 months in last year's assessment.
- Added a new section for reporting renewable generation and storage resources that focuses on and clarifies the dependency of the resource on delayed transmission projects.
- Added fields asking for information on state, federal, and local permitting "downstream" or concurrent with CPUC and California Environmental Quality Act (CEQA) permitting and approvals.
- Added a field for CAISO transmission plan project ID to more easily identify and track transmission projects across data sources, such as the Transmission Project Review (TPR) Process (and more, as overviewed in the next section).
- Added a "Project Type" field to differentiate between various types of network upgrades (e.g., Interconnection Related Reliability Upgrade (IRNU), General Reliability Network Upgrade (GRNU), Local Delivery Network Upgrade (LDNU)) and transmission projects (e.g., TPP approved versus utility self-approved).
- Added fields to establish if generation and storage resources depend on delayed transmission projects to achieve back feed (connection to the grid), or partial or Full Capacity Deliverability Status (FCDS).

CPUC staff will continue to work directly with the PTOs to improve the SB 1174 data template and narrative instructions and improve data accuracy and compliance.

Other State Level Transmission Project Tracking Efforts

Annual SB 1174 transmission system assessments are one of several state level efforts to track the development of transmission projects after they are approved. Other tracking efforts include:

- CPUC's Transmission Project Review (TPR) Process: Includes stakeholder engagement with PG&E, SCE, and SDG&E, and includes the most comprehensive data set on in-development transmission projects with a focus on project costs and permitting.
- CPUC's GO-131E Reporting: Includes permitting and cost data for transmission projects, owned by the investor-owned utilities (IOUs) and independent transmission owners, whose projects require Certificates of Public Convenience and Necessity (CPCNs) and Permits to Construct (PTCs). An important distinction from this report, the GO 131E reporting is only related to the small subset of total transmission projects that are permitted through the CPUC. The vast majority of transmission projects are exempt from new line permitting since they are frequently upgrades to existing corridors and exempt from permitting.
- CAISO Transmission Development Forum (TDF): Semiannual public forum on in-development transmission projects from CPUC jurisdictional and independent transmission owners. TDF data and presentations are used by a wide range of stakeholders as a reliable source of information on transmission project delays and In-Service Dates (ISD) changes. An important distinction from data in this report, TDF data covers all transmission projects that are covered by CAISO transmission planning which is a subset of all transmission under development by utilities.

In addition to these state lead efforts, energy developers, load serving entities, public interest groups, and others do their own transmission project tracking. One example of this is Public Advocates Office Transmission Data Dashboard, which focuses on changes in transmission development costs and timelines.

CPUC staff also work closely with the Governor's Office of Business and Economic Development (GO-Biz) to better understand challenges facing in-development generation and storage resources, including any dependencies on delayed transmission projects, and coordinate with transmission owners and energy developers to help them overcome problems in interconnection project development as they arise.

The SB 1174 transmission system assessment is unique among the tracking initiatives listed above, because it includes the only source of data that connects specific transmission projects to the in-development generation and storage resources that depend on them to come online. All the initiatives listed above are important elements that help state agencies and the CAISO monitor transmission projects through the design, engineering, permitting, construction, and commissioning phases. CPUC staff continue to work with utilities, state agencies, CAISO, developers, and other stakeholders to improve the SB 1174 assessment, and make it a better complement to these other initiatives.

Assessment Part 1: Transmission Project Delays

The PTOs were required to report all transmission projects currently in development and all transmission projects that have come online between January 1, 2025 and December 31, 2025. "Transmission projects" include transmission projects, interconnection projects, and network upgrades, that are CAISO-approved or utility self-approved. A transmission project is considered "in development" if it is in any stage of development (e.g., planning, permitting, engineering, construction) but not yet online. The PTOs were required to report on transmission projects that meet the above criteria regardless of if they are delayed or not, and regardless of whether they are needed for generator or storage resource interconnection.

A transmission project is "delayed" when its current or actual ISD is later than the transmission project's original ISD. Original ISDs are determined via CAISO transmission plans, Transmission Project Review (TPR) Process data, Transmission Development Forum (TDF) data, or the internal utility business case or project approval. Energy Division staff note that major transmission project design changes often occur after project approval, contributing to the large volume of delayed projects present within this assessment.

Overall, the PTOs reported ISD delays for 66.6 percent of in-development transmission projects.

Table 1: 2026 SB 1174 Data Reported and Delayed In-Development Transmission Projects by PTO

	PG&E	SCE	SDG&E	Totals
Reported	171	73	169	413
Delayed	114	59	102	275
Percent	**66.7%**	**80.8%**	**60.4%**	**66.6%**

Volume of Renewable Energy Generation & Storage Resources Reported

To better understand the significance of generation and storage resources reported in SB 1174 data compared to all PG&E, SCE, and SDG&E resources in the interconnection queue, CPUC staff compared the total volume of reported generation and storage resources (with executed Interconnection Agreements (IA)) reported by the PTOs in their SB 1174 data templates, to the volumes of resources (with executed IAs) in the CAISO queue as of July 2026. This comparison excludes resources reported in SB 1174 data that fall under each PTO's Wholesale Distribution Access Tariff (WDAT), as these WDAT resources are not in the CAISO queue.

Figure 1 shows that PG&E and SCE reported volumes of resources in SB 1174 data similar to the total resources in the queue (with executed IAs) that are expected to interconnect in each PTO's respective service territory. However, SDG&E reported far fewer resources in its SB 1174 data than what was seen in the July 2026 CAISO queue snapshot. As of this report, the reason for SDG&E's reporting discrepancy has not been determined. SDG&E also under-reported resources in its 2025 SB 1174 data template, because only RPS eligible resources being procured by SDG&E were reported, rather than what was asked for: all resources with executed interconnection agreements expected to interconnect within SDG&E's territory.

Figure 1: 2026 SB 1174 Data vs. CAISO Queue (July 2026) (Excluding WDAT)
Total Capacity (GW) by PTO

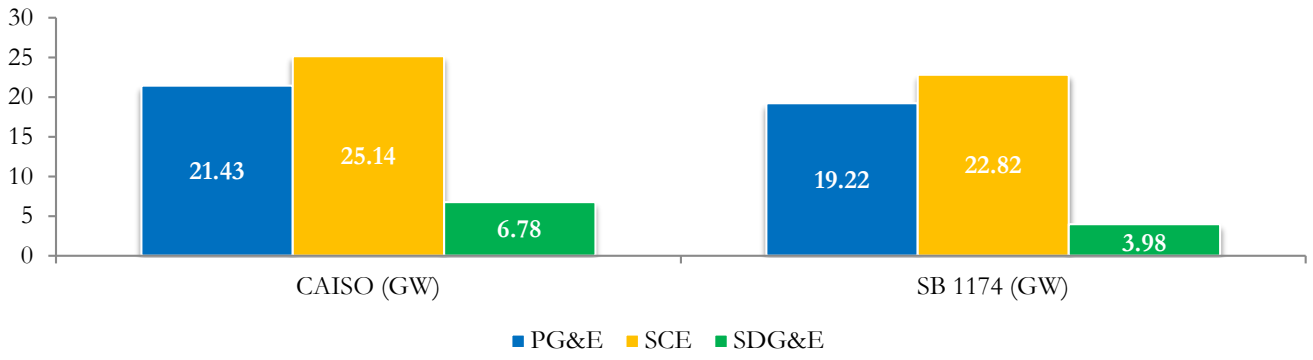


Table 2 shows the volume of resources reported in SB 1174 versus the CAISO queue, as of July 2026, containing approximately 61.8 GW of resources with executed IAs, and including resources from transmission owners beyond PG&E, SCE, and SDG&E (specifically DCRT, GLW, and VEA). SB 1174 resource volumes are representative of PTO CAISO queue volumes and constitute a majority (73.6 percent) of all resources in the queue. The reasons for the SB 1174 data only including a percentage of all resources in the queue are varied. One reason is that some projects in the queue represent projects that have 'reentered' the queue for a change to the project (e.g., size of project or addition of technology). Additionally, some generators in queue may not be transmission dependent. CPUC plans to explore this issue and its causes further in the coming year.

Table 2: 2026 SB 1174 Data Resources Reported and Percentage of Overall CAISO Queue (July 2026)

	Resources Reported in SB 1174 (Excludes reported WDAT resources) (GW)	SB 1174 Resources Percentage of All Resources in CAISO Queue (61.8 GW) (%)
PG&E	19.2	31.1%
SCE	22.8	36.1%
SDG&E	4.0	6.4%
TOTAL	**46.0**	**73.6%**

Primary Reasons for Delay

The PTOs were required to attribute a primary reason for delay for any transmission project included in the 2026 SB 1174 dataset that has a planned or actual ISD that is later than the original ISD. CPUC staff provided the PTOs with 17 choices in attributing a primary delay reason. Table 3 below provides a breakdown of all delayed transmission projects by delay reason. Note that not all 17 reasons for delay were reported by the PTOs.

Project Design was the most attributed reason for delay by the PTOs, with 94 total projects. However, the majority of those (70) were reported by SDG&E – which is 69% of their reported delayed transmission

projects. The 2026 SB 1174 Reporting Template defined Project Design as "any additional planning or design work outside of the initially approved project design, not related to 'Workforce Availability', 'Bundling Dependencies' or 'Clearances'. This additional work can include material modifications."

Table 3 shows the total number of projects reported by each PTO for each delay reason.

Table 3: 2026 SB 1174 Data Transmission Project Delay Reasons by PTO

Delay Reason	PG&E	SCE	SDG&E	TOTALS
Bundling Dependencies	29	11	2	42
Clearances	1	--	--	1
Financing	8	--	--	8
Force Majeure	1	--	2	3
Land	27	--	2	29
Material	6	16	8	30
Outage	--	4	4	8
Permitting (CPUC/CEQA)[5]	13	1	1	15
Permitting (non-CPUC/CEQA)	5	1	5	11
Project Design	18	6	70	94
Vendor/Third Party Delays	--	20	1	21
Workforce Availability	6	--	7	13
TOTAL	**114**	**59**	**102**	**275**

PG&E's Delay Reasons

The largest number of PG&E's delayed transmission projects (29) are primarily delayed due to bundling dependencies, in which work on one project cannot continue until work on other dependent transmission upgrade has been completed. This reason for delay could indicate a systematic problem of insufficient slack in project schedules to accommodate unforeseen changes. Land was attributed as the delay reason for 27 delayed transmission projects, making it PG&E's second most reported primary delay reason. Bundling Dependencies was also PG&E's largest delay reason in the previous reporting period.

[5] The number of projects listed for CPUC/CEQA permitting for PG&E (13) exceeds the number of active CPUC applications PG&E has actively filed at PG&E for transmission permits (8). This row may include projects that have not yet been filed with the CPUC for review. See currently active permitting projects at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/permitting-and-environmental-review/current-projects.

SCE's Delay Reasons

For SCE, the largest number of delays to transmission projects (20) were due to Vendor/Third Party Delays and the second most were due to Material (16). In 2025, SCE reported significantly fewer delays (three projects) due to vendor-related reasons. Vendor/Third Party Delays are defined as, "Issues with vendor/suppliers that are not related to the failure of equipment, material, or components (see 'Material'). These issues can include establishing functional SCADA networks, Real-time Terminal Units, and service links from telecommunications providers essential for operational control and monitoring."

"Material" delays as defined in the 2025 SB 1174 assessment were renamed and slightly redefined as "Procurement" delays in the 2026 assessment. It is possible that many SCE "Material" delays reported in 2026 should have been labeled as "Procurement" delays; evidence of this is seen in SCE's notes for six of the 16 reported "Material" delays indicating that these 6 delays are directly tied to long lead time procurement issues (mostly circuit breaker procurement).

SDG&E's Delay Reasons

The majority (69 percent) of SDG&E's reported delayed transmission projects were delayed due to Project Design (70). This suggests that SDG&E's approved transmission projects regularly do not account for aspects of the final plan, design, or scope of the project, and need to be reassessed after approval.

Secondary and Other Reasons for Delay

In the March 2026 ACR, the PTOs were asked to provide additional context for delayed transmission projects in the form of secondary or other reasons for delay in addition to identifying a primary delay reason. Additionally, the PTOs were instructed to describe "any secondary reasons that have had a substantial impact on the project's delays" when discussing the top three transmission projects that have been delayed.

Bundling Dependencies was not only PG&E's most reported primary reasons for delay, but it was also its most reported secondary delay (14 projects) and correlates with their most listed secondary reason, project or design changes (11 projects). SCE noted vendor/third-party delays (three projects) and material availability (three projects) as secondary or other reasons for delay. This correlates with SCE reporting Vendor/Third Party Delays and Material as their most significant two primary reasons for delay as well. SDG&E provided detailed narrative context for 13 delayed transmission projects rather than categorical tags. SDG&E most often mentioned scope and design revisions, which reinforce Project Design as their top delay reason, followed by permitting and land-rights constraints.

Delay Resolvers

For delayed transmission projects, PTOs identified which party can resolve the current delay (the delay resolver). "Resolving" a delay implies solving it and preventing it from further slowing the project's schedule. CPUC staff provided 11 delay resolver choices, of which the PTOs reported four specific delay

resolvers. As seen in Figure 2 and Table 4 below, for most delayed transmission projects (67 percent), the utility is responsible for resolving the primary delay.

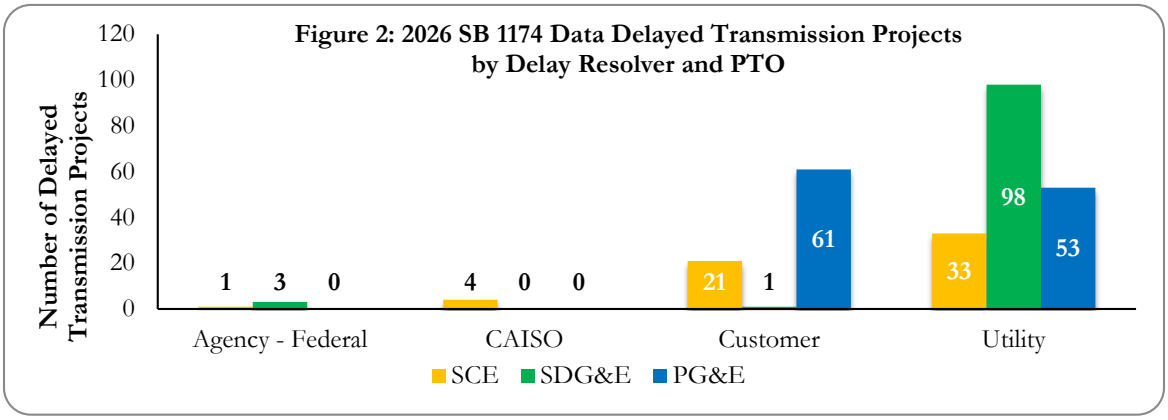


Table 4: 2026 SB 1174 Data Delayed Transmission Projects by Delay Resolvers and PTO				
Delay Resolver	**PG&E**	**SCE**	**SDG&E**	**TOTAL**
Agency - Federal	**0**	**1**	**3**	**4**
CAISO	**0**	**4**	**0**	**4**
Customer	**61**	**21**	**1**	**83**
Utility	**53**	**33**	**98**	**184**
TOTAL	**114**	**59**	**102**	**275**

However, for over half of PG&E's delayed transmission projects, interconnection customers were reported as the primary delay resolver. For some of these delays, city and county permitting and site control were prominent issues.

SCE reported four transmission projects where CAISO is the delay resolver. For these projects, SCE reported the delay reason as "Outage", with notes that include a variety of explanations for delays, such as material delivery delays, outages, construction sequencing, project constraints and scope changes, planning and funding approvals, and environmental/licensing evaluations. It is unclear why CAISO is the delay resolver, but in some cases when new information about project costs, scope, and timelines comes to light, CAISO will re-examine an already approved transmission project causing the project to be put on hold.

SDG&E reported three transmission projects with federal agency delay resolvers concerning National Environmental Policy Act (NEPA) permitting and land rights around Marine Corps Base Camp Pendleton.

Median Delay Times for Delayed Transmission Projects

This assessment considers the length of delay, in months, for each delay reason by calculating the median delay time using data from all reported delayed transmission projects, including those currently in development and those completed January 1, 2025 to December 31, 2025.

Table 5: 2026 SB 1174 Data Median Delay Times by Reason, by PTO (Months)

Delay Reason	PG&E	SCE	SDG&E	All PTO
Bundling Dependencies	31.4	48.7	63.9	33.1
Clearances	12.2	--	--	12.2
Financing	33.7	--	--	33.7
Force Majeure	57.8	--	31.22	54.8
Land	35.3	--	48.3	35.3
Material	4.7	14.6	9.7	11.8
Outage	--	21.3	33.0	21.3
Permitting (CPUC/CEQA)	21.8	27.4	20.8	21.8
Permitting (non-CPUC/CEQA)	18.9	117.4	14	18.9
Project Design	15.1	32	28.4	27.0
Vendor/Third Party Delays	--	38.9	0.5	38.5
Workforce Availability	29.1	--	22.9	29.13
All Reasons (median)	**28.2**	**30.3**	**22.8**	**27.5**

Of note are the varying median delay times amongst the three PTOs. For example, for Bundling Dependencies delays, SDG&E's median delay time (63.9 months) is more than double PG&E's median delay time (31.4 months). These variances could be due to project outliers skewing median delay times, PTOs having varying interpretations of a delay reason, and/or PTOs facing unique challenges within their respective territories. One example of outlier influence is SCE's Lugo-Victorville RAS project, which is delayed by over 117 months due to Permitting (non-CPUC/CEQA). This project experienced nearly an eight-year delay in the Bureau of Land Management (BLM) permitting process and required scope revisions and resubmittal due to evolving project requirements.

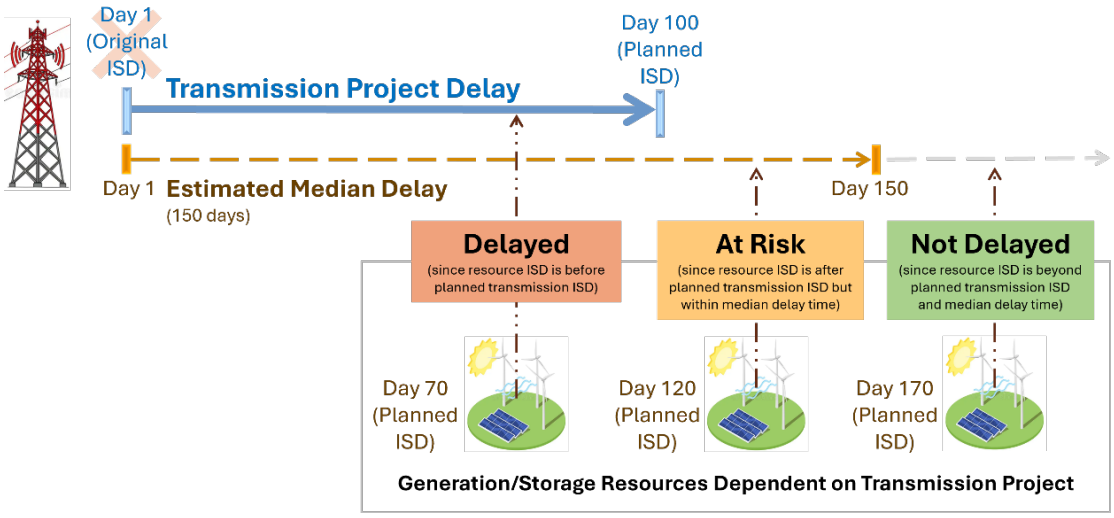
Table 5 above shows that the highest median delay times for PG&E are due to Force Majeure, Land, and Financing, and that all delay reasons have a median delay of at least 12 months, except for Material. The Force Majeure median delay time of 57.8 months is an outlier corresponding to a single delayed, storage project that is being delayed due to a required substation upgrade. For SCE, Bundling Dependencies and Vendor/Third Party Delays had the longest median delay times, and all types of reported delays have a median delay time of at least 12 months. SDG&E reported the highest median delay times for Bundling Dependencies, Land, and Outage. All delay reasons have a median delay of at least 12 months, except for Material and Vendor/Third Party Delays. SDG&E's Bundling Dependencies, with a median delay time of 63.9 months, is the second highest median delay time amongst all PTOs, although SDG&E reported just two projects delayed for this reason.

Assessment Part 2: Impact of Transmission Project Delays on Reported Renewable and Storage Resources

PTOs were required to submit data on generation and storage resources with executed interconnection agreements that are expected to come online in their service territories and were not yet in-service at the time of reporting.[6] Additionally, for each reported transmission project, PTOs identified which resources depend on the project. CPUC staff used the ISDs of these transmission projects and dependent resources to categorize resources as "Delayed", "At Risk", or "Not Delayed". Delayed and At Risk resources provide insight into impacts that may occur unless transmission project ISDs are brought in, while Not Delayed resources provide context to the significance of Delayed and At Risk dependent resources. These three categories are defined below and illustrated in Figure 3.

1) **Delayed**: The resource's current ISD is before the current ISD of the transmission project that it depends on.
2) **At Risk**: The resource's current ISD is after the current ISD of the transmission project that it depends on; AND the resource's ISD is before the delayed transmission project's original ISD plus the median delay time for the project's delay reason.
3) **Not Delayed**:
    a. The resource does not depend on a transmission project; OR
    b. The resource's ISD is after the current ISD of a transmission project(s) it depends on; AND the resource's ISD is after the delayed transmission project's original ISD plus the median delay time for the project's delay reason.

Figure 3: Example of Not Delayed, At Risk, and Delayed Renewable Generation and Storage Resources



[6] The scope of resources requested includes all resources not yet in-service, with executed interconnection agreements, regardless of whether the IOU or any other load serving entity has contracted with the resource, and regardless of whether the resource has been procured for RPS compliance.

This assessment focuses on the impact of transmission project delays on generation and storage resources and does not consider other causes for resources being delayed. Resources categorized here as Not Delayed can still become delayed and have ISD changes not related to transmission projects that they depend on.

Reported Renewable Generation and Storage Resources

There were 146 delayed transmission projects reported as having renewable generation or storage resources dependent on them. Renewable generation or storage resources are considered dependent on a transmission project if the resource requires the transmission project to come online before it can fully or partially provide capacity and/or deliver energy to the grid.

Table 6 below breaks down renewable generation and storage resources by PTO, as well as those resources that are dependent on currently in-development transmission projects that have experienced a delay. Table 6 shows that 127 of 292 (43.5 percent) of reported renewable generation or storage resources are dependent on delayed transmission projects. However, those 127 resources represent 62.7 percent of the capacity (GW) of reported renewable generation or storage resources reported.

Table 6: 2026 SB 1174 Data Renewable Generation and Storage Resources by PTO

	All Resources Reported		Resources Reported Dependent on Delayed Transmission Projects	
PTO	**Total**	**Capacity (GW)**	**Total**	**Capacity (GW)**
PG&E	171	19.5	66	13.8
SCE	108	25.4	61	16.9
SDG&E	13	4.0	0	0
TOTAL	**292**	**48.8**	**127**	**30.6**

Of note, both PG&E and SCE have a similar amount of capacity and number of resources dependent on delayed transmission projects, despite SCE reporting far fewer total resources. Also, SDG&E reported significantly fewer resources, and it reported that none of those resources are dependent on transmission projects and can achieve deliverability otherwise.

Renewable Generation and Storage Resources Delayed and At Risk of Delay

Figures 4 and 5 below illustrate the capacity of renewable generation and storage resources that CPUC staff categorized as Delayed or At Risk for Delay for PG&E and SCE respectively. SDG&E reported that they had no renewable generation and storage resources that are dependent on delayed transmission projects and so SDG&E's data will not be discussed in this section.

Close to half of PG&E's resources that depend on delayed transmission projects are stand-alone storage resources (6.2 GW), compared to hybrid renewable generation plus storage (6.9 GW). Figure 4 shows that 5.6 GW of resources are expected to be delayed due to delayed transmission projects, and an additional 1.9 GW are at risk. About half of SCE's delayed and at-risk resources are hybrid renewable generation plus

storage (7.3 GW). Figure 5 shows that most SCE's resources (14.08 GW) are expected to be delayed due to delayed transmission projects, and an additional 0.9 GW are at risk.

Figure 4: PG&E In Development Renewable and Storage Resources Delayed or At Risk for Delay

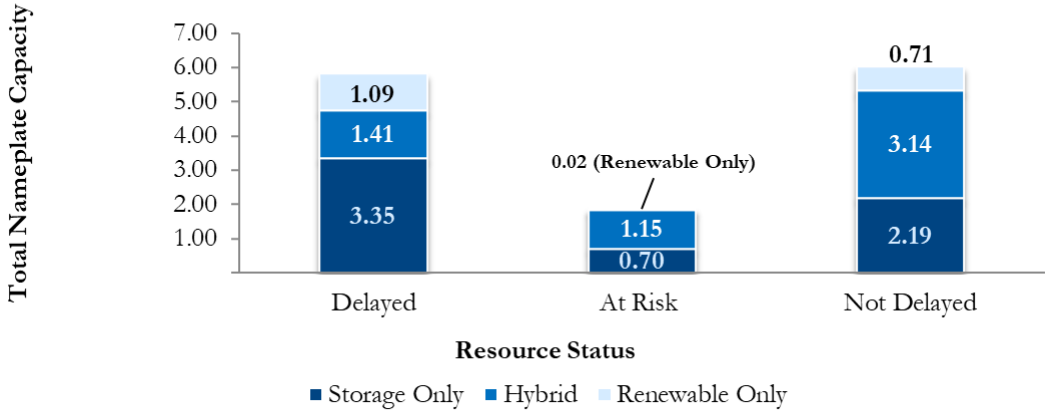
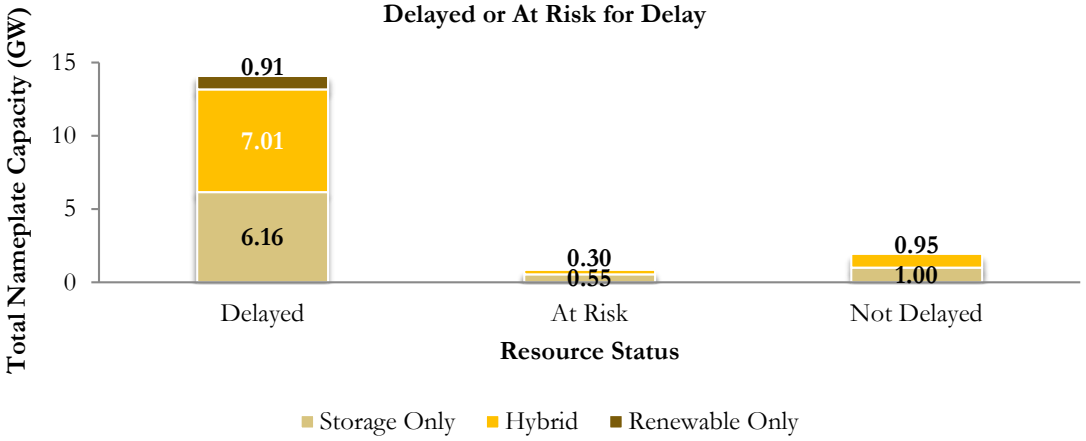


Figure 5: SCE 2026 SB 1174 Data Renewable and Storage Resources Delayed or At Risk for Delay



Reasons For Transmission Project Delays

Figures 6 and 7 below further break down the renewable generation and storage resources impacted by delayed transmission projects by looking at each reported transmission project delay reason and delay resolver combination. For PG&E, the most delayed resource capacity is behind transmission projects delayed due to Bundling Dependencies and Project Design where PG&E is the delay resolver.

Figure 6: PG&E 2026 SB 1174 Data Renewable Energy Generation and Storage Resources Dependent on Delayed Transmission Projects by Delay Reason and Resolver

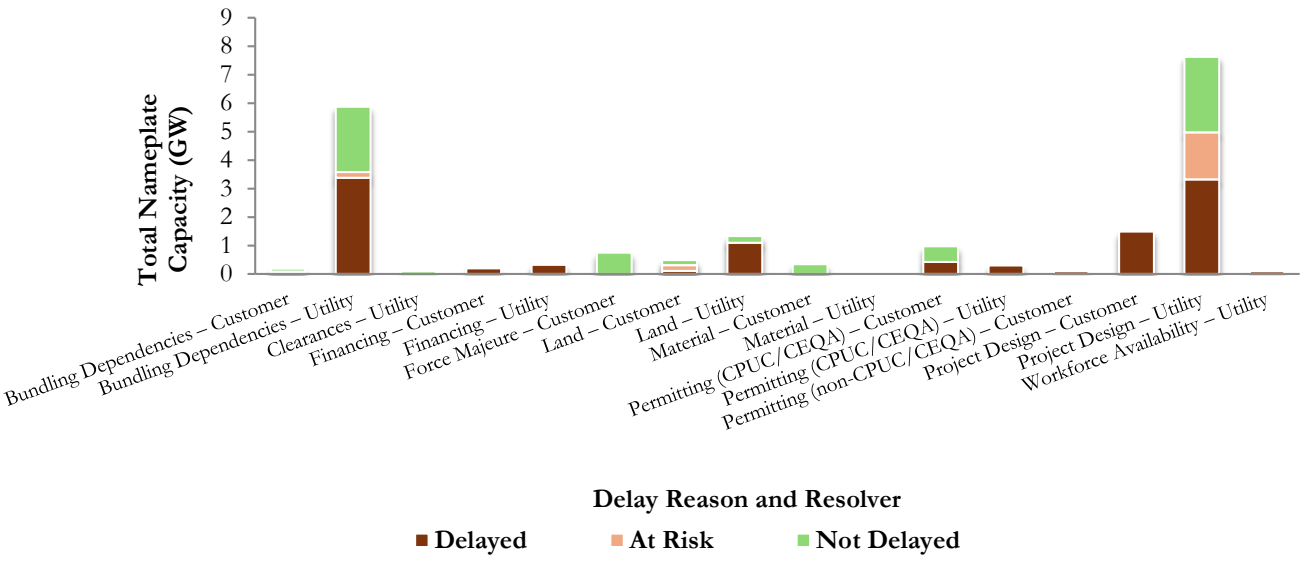
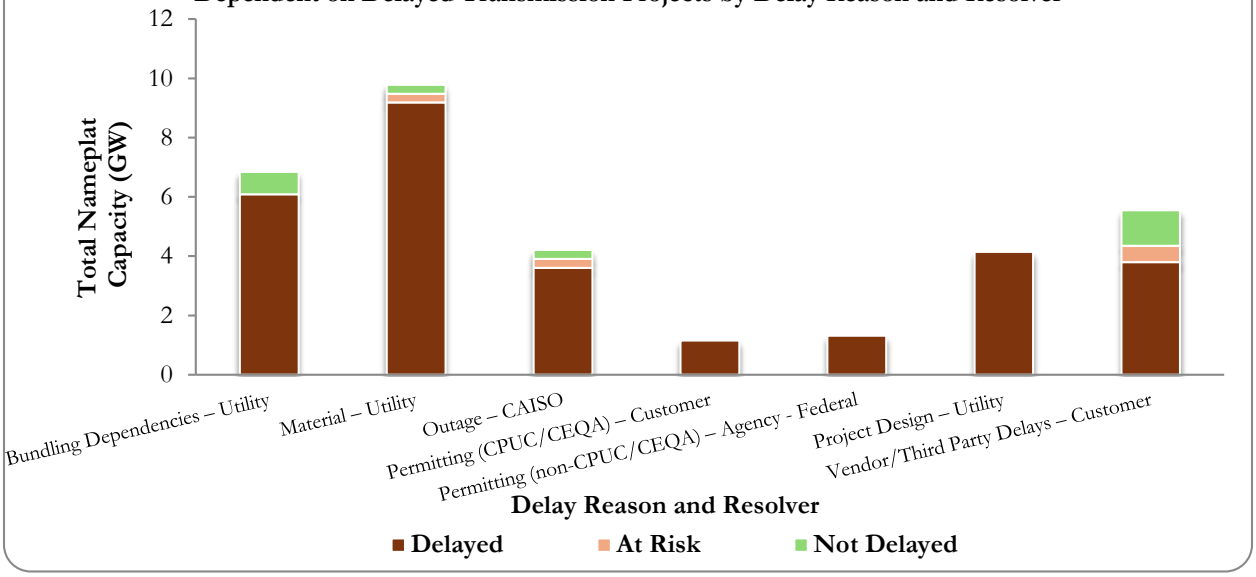


Figure 7 below illustrates that the majority of SCE's delayed resource capacity is impacted by delays that will be resolved by the utility. The most impactful reasons for delay are Material (related to supply chain issues and the procurement of long lead-time resources) and Bundling Dependency Delays, with other prominent delay reasons including Project Design, Vendor/Third Party, and Outage. In most cases SCE attributed themselves as the delay resolver, except for Vendor/Third party delays and permitting delays where SCE attributes the interconnection customer as the delay resolver.

Figure 7: SCE 2026 SB 1174 Data Renewable Energy Generation and Storage Resources Dependent on Delayed Transmission Projects by Delay Reason and Resolver



Transmission Projects with Largest Impacts on Renewable Generation and Storage Resources

The three PTOs reported 22.3 GW of renewable generation and storage resources that have been delayed or are at risk of being delayed due to the delayed transmission projects they depend on. Much of this 22.3 GW is dependent on a small number of "high impact" delayed transmission projects. Resolving delays to these high impact projects should remain a high priority for the PTOs and state agencies.

High Impact Projects

Table 7 below lists the top PG&E transmission projects in terms of most dependent Delayed and At Risk renewable generation and storage resource capacity.

Table 7: PG&E 2026 SB 1174 Data High Impact Transmission Projects

PG&E Transmission Project	Total Capacity Delayed (GW)	Total Capacity At Risk (GW)	Total Capacity Delayed + At Risk (GW)
Tesla-Tracy 230KV Line #2 Relocation	0	4.0	4.0
Pittsburg 230KV Bus Overstress	2.3	0	2.3
New SS For Los Banos-Panoche 230KV	0.7	0.4	1.1
SS Loop-In Los Banos-Dos Amigos 230KV	0.9	0.2	1.1
SS Loop-In Dos Amigos-Panoche 230KV	0.9	0.2	1.1
Dos Amigos Line Mod (2 CKTS Into New SS)	0.7	0.4	1.1
SS Los Banos-Panoche Perm Land ACQ	0.7	0.4	1.1
TOTAL	**6.2**	**5.6**	**11.8**

Table 8 below lists the top SCE transmission projects in terms of most dependent Delayed and At Risk renewable generation and storage resource capacity.

Table 8: SCE 2026 SB 1174 Data High Impact Transmission Projects

SCE Transmission Project	Total Capacity Delayed (GW)	Total Capacity At Risk (GW)	Total Capacity Delayed + At Risk (GW)
New Serrano 4AA 500/230 kV Bank and 230 kV GIS Rebuild	5.3	0	5.3
Serrano 500 kV SCD Mitigation	4.2	0	4.2
Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	3.4	0	3.4
Devers-Valley No.1 500 kV Line Upgrade	3.4	0	3.4
San Bernardino-Vista 230 kV 1 Line Upgrade	2.6	0	2.6
Devers-Red Bluff No.1 and No.2 500 kV Line Upgrade	2.5	0	2.5
TOT903 - Q1625 - Angeleno Solar Farm	1.2	0	1.2
Lugo-Victorville Centralized RAS	1.1	0	1.1
Sanborn Hybrid 3 - TOT915_Q1632	0.9	0	0.9
Windhub 220 kV - TOT985 - Q1791 - Sanborn 5 Hybrid	0.6	0	0.6
TOTAL	**25.2**	**0**	**25.2**

Assessment Part 3: Permitting Analysis

PTOs reported information on the permitting status of transmission projects and categorized permitting related delays as either "Permitting (CPUC/CEQA)" or "Permitting (non-CPUC/CEQA)" to differentiate between project delays associated with CPUC and CEQA permitting from delays associated with other federal, state, or local permitting beyond CPUC's jurisdiction. It is important to note that in the SB 1174 data template "Permitting (CPUC/CEQA)" delays were defined as: "Project delays related to CPUC permitting or CEQA environmental reviews. Some examples include delays in preparation of environmental documents, biological or cultural resource surveys, mitigation measure implementation, coordination with environmental agencies".

It's also important to note that delays related to CPUC permitting and the CEQA review processes are not necessarily caused by the CPUC. For instance, the permit applicant or another entity could be delayed in providing required information, or a delay in CEQA review/permitting could be caused by the need to incorporate project design changes. Table 9 shows the number of reported transmission projects whose primary reason for delay is either CPUC/CEQA permitting or non-CPUC/CEQA permitting and compares this to the number of projects delayed for other reasons (like Bundling Dependencies, Clearances, Financing, Force Majeure, Land, Material, Outage, Project Design, Vendor/Third Party Delays, and Workforce Availability).

Table 9: 2026 SB 1174 Data Delayed Transmission Projects by Permitting Type and PTO

PTO	Delayed for Permitting (CPUC/CEQA)	Delayed for Permitting (non-CPUC/CEQA)	Delayed for Non-Permitting Reason	Total Delayed	Delayed for Permitting (%)
PG&E	13	5	96	114	15.8%
SCE	1	1	57	59	3.4%
SDG&E	1	5	96	102	5.9%
TOTAL	**15**	**11**	**249**	**275**	**9.5%**

It is important to note that in Table 9, and elsewhere in this report, delays (including permitting delays) may or may not be resolved at the time data was reported. The March 2026 ACR did not ask the PTOs to report if the primary delay is ongoing or has been resolved.

PG&E reported 18 projects delayed due to permitting. These projects make up 15.8 percent of all delayed transmission projects reported by PG&E. Thirteen of these projects were reported as delayed due to CPUC permitting and CEQA review; and almost all of these projects are interconnection-related network upgrades where the interconnection customer is attributed as the delay resolver. These delays were noted to be connected to environmental permitting, county building permitting, and easements. From this it is unclear if these delays are related to CPUC/CEQA permitting of transmission projects or network upgrades, rather than permitting of the generation and storage resources seeking interconnection to the grid (generation and storage project permitting is outside of CPUC's jurisdiction). The five PG&E projects delayed due to non-

CPUC/CEQA permitting were related to a single storage project interconnection that experienced delays related to city building permitting.

Of the five SDG&E projects delayed due to non-CPUC/CEQA permitting, three of these projects were delayed due to NEPA permitting and easement issues related to Marine Corp Base Camp Pendleton, and two projects were delayed due to local permitting.

Although there are relatively few permitting delays overall, permitting delays can have a significant impact on the interconnection of new resources. For example, Table 10 shows a single 1.2 GW generation resource that could be delayed from interconnecting due to delayed substation upgrades at its point of interconnection.

Table 10: 2026 SB 1174 Data Dependent Capacity Affected by Permitting Delays (GW)

Delay Category	PTO	Delayed GW	At-Risk GW	Not-Delayed GW	Total Dependent GW
Permitting (CPUC/CEQA)	PG&E	0.4	0	0.6	1.0
	SCE	1.2	0	0	1.2
	SDG&E	0	0	0	0
	TOTAL	**1.6**	**0**	**0.6**	**2.1**
Permitting (non-CPUC/CEQA)	PG&E	0.1	0	0	0.1
	SCE	0	0	1.3	1.3
	SDG&E	0	0	0	0
	TOTAL	**0.1**	**0**	**1.3**	**1.4**
TOTAL		**1.7**	**0**	**1.9**	**3.5**

Permitting Delays by Delay Resolver

Table 11 shows that the majority of permitting related delays were attributed to interconnection customers. In some instances, there are too few projects delayed for a reason/resolver combination to consider its median delay time as significant. For example, although 118.8 months is a high median delay time for PG&E Permitting (CPUC/CEQA) with the Utility as the Delay Resolver, this is only based on one project.

Table 11: 2026 SB 1174 Data Median Delay Times by Permitting Type and Delay Resolver

PTO	Permitting Type	Delay Resolver	Projects	Median Delay (Months)
PG&E	Permitting (CPUC/CEQA)	Customer	12	21.8
PG&E	Permitting (non-CPUC/CEQA)	Customer	5	18.9
SDG&E	Permitting (non-CPUC/CEQA)	Utility	3	6.2
SDG&E	Permitting (non-CPUC/CEQA)	Agency - Federal	2	97.6
PG&E	Permitting (CPUC/CEQA)	Utility	1	118.8
SCE	Permitting (CPUC/CEQA)	Customer	1	27.4
SCE	Permitting (non-CPUC/CEQA)	Agency - Federal	1	117.4
SDG&E	Permitting (CPUC/CEQA)	Utility	1	20.8

Permitting Delays (non-CPUC/CEQA)

IOUs reported on other state and local permitting of transmission projects downstream of CPUC/CEQA permitting, and federal permitting concurrent with CPUC/CEQA permitting. Table 12 summarizes this.

Table 12: 2026 SB 1174 Data Reported Permitting Agencies Related to Non-CPUC/CEQA Delays

PTO	Projects	Downstream Permitting Agency, As Reported
PG&E	5	No permitting agency was listed. PG&E notes exemption from CPUC permitting and projects not subject to NOC, PTC, or CPCN requirements.
SCE	1	SCE listed a GO 131 applicability note, instead of a specific agency.
SDG&E	5	SDG&E listed: 2 Camp Pendleton, 1 Caltrans, and 2 N/A.

Few projects were reported as having permitting dependencies downstream of CPUC/CEQA, and the five PG&E projects in Table 12 are all upgrades needed to allow a single storage project to interconnect. In the case of these five projects, delays were attributed to city level building permitting.

BLM, Caltrans, CA Coastal Commission, and Marine Corps Base Camp Pendleton were all reported as organizations involved in necessary permitting downstream of CPUC/CEQA permitting.

Assessment Part 4: Mitigation Efforts on Transmission Project Delays

Within 2026 Draft RPS Procurement Plans, the PTOs described mitigation efforts and business process improvements in 2025 to address the most significant reasons for delays to transmission in-service dates. Each PTO reported advancing procurement of long-lead materials earlier in the project lifecycle, and measures to secure supplier or manufacturing capacity ahead of need. PG&E and SDG&E both reported strengthened coordination with interconnection customers. No PTO described a programmatic mitigation measure directed at permitting delays, which account for 26 delayed projects and 1.7 GW of delayed dependent capacity, though each PTO addressed permitting delays separately in its narrative response.

PG&E

PG&E reported that its 2025 mitigation efforts focused primarily on supply chain constraints and long-lead equipment availability. The utility advanced the release of investment funding earlier in the project lifecycle to enable earlier procurement of critical materials, reducing exposure to manufacturing and delivery schedule risk. PG&E also enhanced coordination across internal functions to improve the timing and execution of long-lead material ordering, including interim processes to accelerate procurement activities.

To further mitigate equipment-related delays, PG&E implemented a strategic sourcing approach, proactively identifying suppliers and placing bulk orders for materials with extended lead times, such as transformers and circuit breakers. The utility reported working with suppliers to align its long-range demand against their annual production capacity, particularly for 230 kilovolt (kV) and 500 kV class circuit breakers.

At the project level, PG&E described measures addressing several of its most significant delay categories. For the Manning Substation project, PG&E reported that a partial Environmental Release to Construction was issued to allow portions of the substation scope to proceed while remaining easements and access agreements were finalized, and that the project advanced land access and right-of-way readiness through early landowner engagement and contingency measures such as right-of-entry agreements. Long-lead materials including conductor and 230 kV breakers were ordered or in the process of being secured. For the Pittsburg 230 kV Bus Overstress project, with delays PG&E attributed primarily to bundling dependencies, the utility completed upfront planning and initiated a system impact analysis in coordination with Transmission Planning and Protection Engineering. For the Tesla-Tracy 230 kV Line #2 Relocation, PG&E conducted geologic mapping of the Midway fault to resolve substation siting and configuration questions.

PG&E's programmatic mitigation response addresses supply chain and equipment availability, a category accounting for six of its 114 delayed projects. PG&E's four largest reported categories of delayed transmission projects are Bundling Dependencies (29), Land (27), Project Design (18), and Permitting subject to CPUC or CEQA review (13). Importantly, most of these 13 permitting related delays are attributed to interconnection customers rather than CPUC or CEQA permitting. Measures addressing all delay categories appear in PG&E's project-level responses.

SCE

SCE created a Transmission and Substation Project Development team to oversee the full-scope development and end-to-end engineering sponsorship of transmission and substation projects, addressing interconnection needs alongside reliability, load growth, and other operational needs. Design, scope development, and project portfolio coordination and prioritization were consolidated within the team, which SCE reported was intended to accelerate project timelines and simplify coordination, particularly for complex and large-scale projects.

SCE described its implementation of Shared Network Upgrade requirements established through CAISO's second 2023 IPE Track 2 filing, which FERC accepted in December 2024. Under these requirements, all Transmission Owner Tariff projects sharing a network upgrade must execute an interconnection or Engineering and Procurement agreement and provide the third posting of Interconnection Financial Security, after which SCE must begin construction within 30 days. SCE reported requesting voluntary compliance from queue cluster 13 and 14 interconnection customers under the Wholesale Distribution Access Tariff, and that it will finance WDAT-allocated shared network upgrade costs upfront where necessary to minimize construction delays. SCE reported that CAISO's June 5, 2026 IPE 5.0 filing extends these requirements to queue cluster 15 and on, and that SCE is preparing a WDAT amendment.

Through its Intra-Cluster Prioritization process for reliability network upgrades, SCE enabled seven projects totaling 2.4 GW to advance projected completion dates by two or more years, while remaining projects in the cluster continue to await completion of long lead-time downstream network upgrades. An additional four projects totaling 1.2 GW received prioritization within their cluster but must request a Limited Operation Study before advancing.

At the project level, SCE attributed delays to the New Serrano 4AA 500/230 kV Bank and 230 kV gas-insulated (GIS) Rebuild, the Serrano 500 kV SCD Mitigation, and the Serrano-Alberhill-Valley 500 kV 1 Line Upgrade to the limited pool of vendors able to build and install GIS switchgear at Serrano Substation, and specifically to the production capacity and delivery schedule of the selected Engineering, Procurement, and Construction (EPC) contractor. SCE reported incorporating design modifications identified in preliminary design meetings to streamline construction and identifying operational mitigations to reduce high short circuit duty between the initial proposed operating date and project completion. For 2026 and 2027, SCE reported it will continue working with the vendor to identify efficiencies and opportunities to compress the schedule.

CPUC staff observed that SCE's reported measures align more closely with its reported delay drivers. Vendor and Third Party Delays (20) and Material (16) are SCE's two largest categories, and the reported vendor capacity and scheduling work speaks to both. SCE accounts for 20 of the 21 Vendor and Third Party Delays reported statewide.

SDG&E

SDG&E reported that in 2025 it implemented or maintained targeted processes, resources, and procurement strategies intended to prevent interconnection delays. On project management, SDG&E reported initiating projects early following execution of a Generator Interconnection Agreement, assigning dedicated project management teams to interconnection projects, maintaining continuous tracking at the director and executive level, and coordinating closely with customers to improve schedule reliability. On resources, SDG&E reported proactively maintaining appropriate staffing levels and leveraging ready contractors, which it described as ensuring projects were not delayed by labor or funding constraints. On procurement, SDG&E reported advancing early procurement of long-lead materials, diversifying vendors, and reserving manufacturing capacity. SDG&E characterized these efforts collectively as reducing risks associated with supply chain, labor, and coordination challenges, and as supporting more reliable interconnection timelines for generation and storage resource development.

At the project level, SDG&E reported that no delayed transmission project in its portfolio has dependent generation or storage capacity, and that it therefore had no high-impact delayed projects to report. This is consistent with the assessment data, which shows zero dependent capacity for SDG&E across every delay category. In response to an additional CPUC staff request, SDG&E provided supplemental detail on three delayed transmission projects unrelated to renewable or storage resources. For the TL695/TL6971 Reconductor Project, which is delayed approximately 14 months by Camp Pendleton environmental review and federal easement renewal, SDG&E reported monthly meetings with Camp Pendleton and offers to assist its staff with documentation preparation, continuing through 2027. For the TL627 Wood to Steel project, delayed approximately two months by the Caltrans permit process, SDG&E reported performing an environmental study and engineering estimate for a proposed reroute and submitting a revised application. For the Jamacha Substation Rebuild, delayed approximately five months by weather and the resulting need to coordinate with internal engineering, SDG&E reported securing additional construction days and coordinating with internal engineers to address workforce availability limitations.

CPUC staff observed that SDG&E's reported measures address procurement, staffing, and coordination. Project Design accounts for 70 of SDG&E's 102 delayed projects, 74 percent of all Project Design delays reported, and is not directly addressed by the measures described.

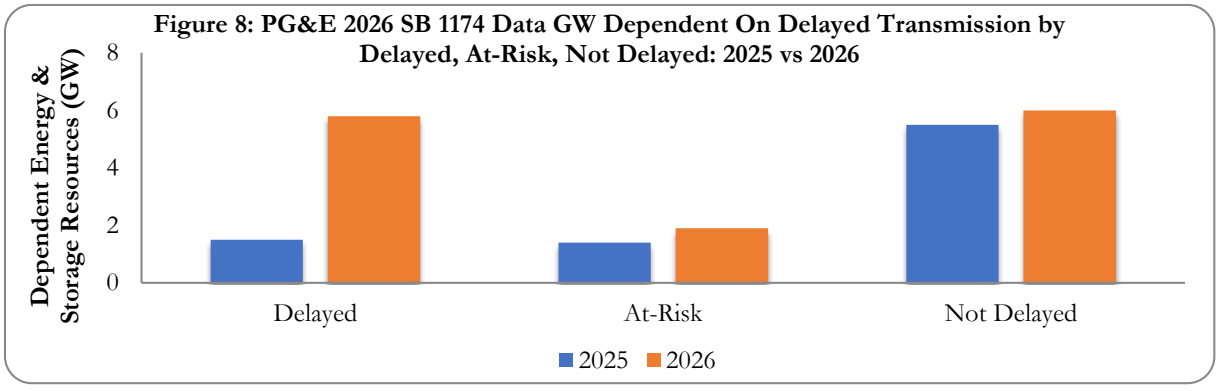
Assessment Part 5: SB 1174 Year Over Year Compared

As SB 1174 data reporting has become more mature since 2024, there is now an opportunity to compare data and analysis reported in 2025 versus 2026 to identify changing trends in the transmission system. Table 13 below compares the renewable generation and storage resource capacity reported by PG&E, SCE, and SDG&E in 2025 and 2026. The total reported capacity grew from about 40.7 GW to 49.0 GW, and the capacity dependent on delayed transmission projects grew more significantly, from roughly 21.8 GW to 30.6 GW.

Table 13: 2026 SB 1174 Data Renewable Energy Generation and Storage Resources Reported in 2025 and 2026

PTO	2025		2026	
	Resource Dependent on Delayed Transmission (GW)	Total Resources Reported (GW)	Resource Dependent on Delayed Transmission (GW)	Total Resources Reported (GW)
PG&E	8.5	16.2	13.8	19.5
SCE	13.3	24.3	16.9	25.4
SDG&E	0.00	0.2	0.00	4.0
TOTAL	**21.8**	**40.7**	**30.6**	**48.8**

There has been a significant increase in the volume of generation and storage resources expected to be delayed behind the PG&E and SCE transmission projects that they depend on (Figures 8 and 9 below). This increase in resources categorized as delayed cannot be explained by 2026 increases in the MW of in-development resources seeking interconnection in PG&E and SCE territories, and it could mean that the impact of delayed transmission projects on generation and storage resources is worsening. CPUC staff expect to adapt the 2027 SB 1174 assessment to determine if the impact of delayed transmission projects on generation and storage resources is worsening. SDG&E has not reported any resources as dependent on delayed transmission projects in the last two years.



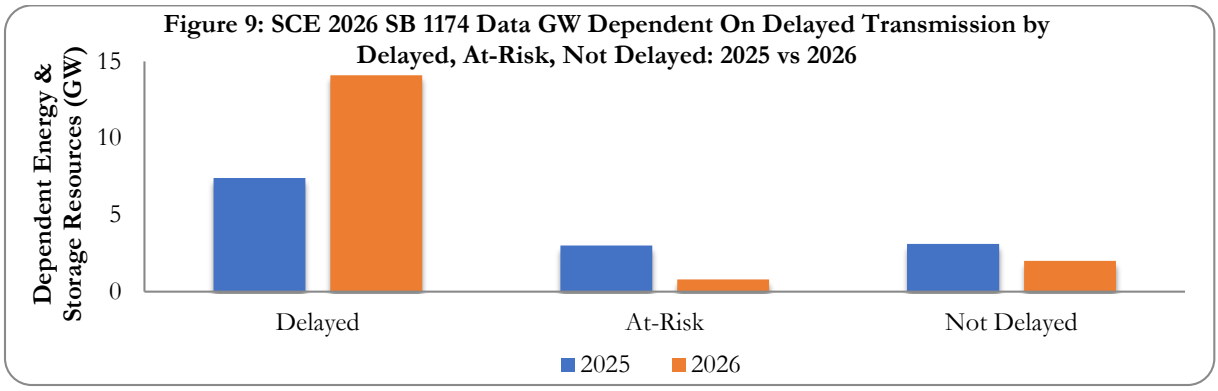


Table 14 below shows that the top reasons for transmission project delays that impact the largest number of GW of generation and storage resources remain largely unchanged between 2025 and 2026.

Table 14: 2026 SB 1174 Data Transmission Project Reasons for Delay Impacting the Largest Volumes of Resources

	2025	2026
PG&E	• Bundling Dependency • Project Design • Financing	• Bundling Dependency • Project Design • Land
SCE	• Material • Bundling Dependency • Customer Initiated	• Material • Bundling Dependency • Project Design

Bundling Dependencies, Project Design, and Material/Procurement delays still affect transmission projects across California, and tackling them should remain a priority for PTOs, state agencies, and policy makers.

Evolution of 2025 "High Impact" Transmission Projects

Table 15 below shows "High Impact" PG&E and SCE projects from the 2025 SB 1174 assessment whose status has changed significantly based on SB 1174 data reported in 2026.

Table 15: 2026 SB 1174 Data SB 1174 High Impact Transmission Projects from 2025 to 2026

PTO	Project Name	2025 Delayed & At-Risk (GW)	2026 Delayed & At-Risk (GW)	Notes
SCE	Lugo-Victorville 500 kV Transmission Line Upgrade	2.6	0.1	Dramatic decrease in dependent resources, as explained below.
SCE	Devers-Valley No.1 500 kV Line Upgrade	2.3	3.4	
SCE	San Bernardino-Vista 230 kV Line Upgrade	1.4	2.6	
PG&E	Vaca Dixon Substation 230 kV Circuit Breakers 442, 452, and 462 overstress	1.4	0	In Service as of 6/25/2026.

In 2026, more generation and storage resources are expected to be delayed behind SCE's Devers-Valley No.1 500 kV line upgrade and San Bernardino-Vista 230 kV line upgrade than were delayed behind these upgrades in 2025. These two transmission upgrades share the same set of dependent resources, and new resources have been added to this set since 2025. These two upgrades continue to have a high impact on generation and storage resources seeking interconnection to the grid; and resolving delays to these two upgrades should remain a priority for SCE and state agencies. PG&E's Vaca Dixon Substation 230 kV circuit breaker 441, 452, 462 upgrades were completed earlier than expected and no longer threaten to delay any resources from interconnecting in PG&E territory. There is also a significant decrease in the volume of resources expected to be delayed by the Lugo-Victorville 500 kV upgrade in 2026.

Fewer Resources Delayed Behind Lugo-Victorville 500 kV Upgrade

Since late 2025, SCE, the CAISO, and Los Angeles Department of Water and Power (LADWP) have been coordinating to prevent the ISD of the Lugo-Victorville 500 kV upgrade from continuing to slip. This is a significant upgrade with over 2,500 MW expected to be delayed by the project (based on the 2025 SB 1174 assessment). The ISD of this project is now stable at March 2027, and fewer resources were reported as being dependent on SCE's Lugo-Victorville 500 kV upgrade in 2026: SCE staff reexamined SCE's 2025 SB 1174 data submission and determined that the following resources had been incorrectly reported as dependent on the Lugo-Victorville 500 kV upgrade: Q1758, Q1761, Q1764, Q1768 , Q2042 , and Q2050 (Q2050 withdrawn from CAISO queue).

Additionally, the following statuses for resources were confirmed:

- Q1647, Q1795, and Q1796 were confirmed as dependent.
- Q1636 and Q1757 are no longer dependent.

Through consultation with CAISO, SCE confirmed that there had been an oversight on the Transmission Plan Deliverability (TPD) allocation report regarding the Lugo-Victorville 500 kV Line Upgrade and identified the following additional resources as dependent on the upgrade: Q1783, Q2066, and WDT1808.

These corrections and new information mean that of the total 2.05 GW of resources reported to be dependent on Lugo-Victorville 500 kV upgrade in 2026 SB 1174 data, only 0.1 GW of these resources are expected to be delayed behind the upgrade, which is significant change from what was reported in 2025.

Assessment Part 6: Findings and Recommendations

Transmission project delays are commonly reported by the PTOs and the reasons for them are complex. This assessment attempts to identify the core reasons for project delays and their impact on renewable generation and storage necessary to meet growing electricity demand and California's greenhouse gas reduction goals. Below are the key findings from this 2026 SB 1174 systemwide assessment.

Part 1 Findings: Transmission Project Delays

- Generation and storage resource volumes reported in SB 1174 are similar to the volume (net GW to grid) of resources PTOs have in the CAISO queue.
- The three PTOs reported in-development transmission project delays of ISDs for 275 out of 413 (66.6 percent) of their transmission projects. Project Design was the most attributed reason for delay impacting 94 projects; the majority of these Project Design delays (70) were reported by SDG&E – making up 69% of their reported delays. The largest number of PG&E and SCE delayed transmission projects are primarily delayed due to Bundling Dependencies (29) and Vendor/Third Party Delays (20) respectively.
- The PTOs identified four parties as responsible for resolving their transmission project delays – the utility itself, interconnection customers, CAISO, and federal agencies. For 67 percent of all transmission project delays, the utility is reported as the delay resolver. For most other delays, interconnection customers are reported as the delay resolver.
- For over half of PG&E's delayed transmission projects, interconnection customers were reported as the delay resolver. For some delays, PG&E did not know the delay cause, but in cases where PG&E had information, city and county permitting and site control were prominent issues.
- Across all delay reasons, the PTOs had an overall median delay of 27.5 months (2.3 years) for delayed in-development transmission projects. The highest median delay times for PG&E are due to Force Majeure, Land, and Financing (however Force Majeure is due to a single delayed project). For SCE, Bundling Dependencies and Vendor/Third Party Delays had the longest median delay times, and all delay reasons reported have a median delay time of at least one year.
- Bundling Dependencies, Land, and Outage were the delay reasons with the highest median delay times reported by SDG&E.

Part 2 Findings: Impact of Transmission Project Delays on Reported Renewable and Storage Resources

- Of the 292 reported renewable generation or storage resources, 127 (43.5 percent) are dependent on delayed transmission projects.
- Most of the resources within PG&E's territory that are dependent on delayed transmission projects are comprised of storage resources at 4.05 GW of capacity; and most of this resource capacity is impacted by utility delays for Bundling Dependencies and Project Design.

- Half of delayed or at risk of being delayed resources for SCE are hybrid renewable generation plus storage resources at 7.3 GW; and most resource capacity is impacted by delays that will be resolved by the utility. Most SCE's resources (14.08 GW) are expected to be delayed due to delayed transmission projects they depend on, and an additional 0.9 GW are at risk.
- SCE's most impactful reasons for delay are Material (related to supply chain issues and the procurement of long lead time resources) and Bundling Dependency Delays, with other prominent delay reasons including Project Design, Vendor/Third Party, and Outage.
- Large volumes of SCE resources are expected to be delayed behind Vendor/Third Party delays and "permitting" delays where SCE attributes the interconnection customer as the delay resolver.

Part 3 Findings: Permitting Analysis

- PG&E reported 18 projects delayed due to permitting, 13 of which were delayed due to CPUC and CEQA permitting; and almost all these are interconnection related network upgrades where the interconnection customer is attributed as the delay resolver. This calls into question if these are delays related to CPUC or CEQA permitting of transmission projects. The five PG&E projects delayed due to non-CPUC/CEQA permitting were related to a single storage project interconnection that experienced delays related to city building permitting.
- Of the five SDG&E projects delayed due to non-CPUC/CEQA permitting, three of these projects were delayed due to NEPA permitting and easement issues related to Marine Corp Base Camp Pendleton, and two projects were delayed due to local permitting.
- The majority of permitting related delays were attributed to interconnection customers. However, for many delay reason/resolver combination, there were too few projects reported to estimate a reliable median delay time.
- Few projects were reported as having permitting dependencies downstream of CPUC/CEQA, but BLM, Caltrans, CA Coastal Commission, and Marine Corps Base Camp Pendleton were all reported as organizations involved in necessary permitting downstream of or concurrent with CPUC/CEQA permitting.

Part 4 Findings: Mitigation Efforts on Transmission Project Delays

- Regarding mitigation efforts for transmission project delays in 2025, PG&E focused on procurement and supply chain management for long-lead equipment. SCE centered on organizational restructuring, interconnection process reform, and digital tooling. SDG&E centered on project management structure, staffing and contractor readiness, and procurement strategy.

Part 5 Findings: SB 1174 Year Over Year Compared

- Between 2025 and 2026 the total reported volume of generation and storage resources grew from about 40.7 GW to 48.8 GW, while the volume dependent on delayed transmission projects grew

more sharply, from roughly 21.8 GW to 30.6 GW. The volume of PG&E and SCE resources expected to be delayed behind delayed transmission projects also increased significantly.
- Top reasons for transmission project delays in 2025 and 2026 are largely the same, and include: Bundling Dependencies, Project Design, and Material/Procurement delays.
- In 2026 even more generation and storage resources are expected to be delayed behind SCE's Devers-Valley No.1 500 kV line upgrade and San Bernardino-Vista 230 kV line upgrade than were delayed behind these upgrades in 2025.
- Data corrections and new information in 2026 about resources dependent on the Lugo-Victorville 500 kV upgrade show that significantly fewer resources (100 MW) are expected to be delayed behind the upgrade, than what was determined in the 2025 SB 1174 assessment.

Recommendations

From conducting this 2026 SB 1174 systemwide assessment on delayed transmission projects and their impact on renewable generation and storage resources, CPUC staff offer these recommendations.

Minimize Project Redesigns

Large volumes of generation and storage resources are expected to be delayed behind transmission projects delayed by "Project Design". These delays occur when transmission projects are redesigned due to things like scope changes, engineering complexity changes, cost re-estimation, dependencies on other projects, and project changes driven by interconnection customers. Some of these changes are a natural part of the design process and arise as new information about project requirements and constraints is discovered. However, utilities can minimize the need for project redesigns by:

- Committing more resources — before project approval — to investigate potential design and engineering issues and set more realistic timeline and cost expectations for projects to mitigate "bundling dependency" delays by building more slack into project schedules.
- Creating and using more flexible processes for prioritizing and reprioritizing projects. For example, utilities could better leverage transmission capital steering committees, increase the number of dedicated transmission project managers, or increase their engineering workforce.

Improve Long-Lead Time Procurement

The PTOs have reported long-lead times for procurement of transmission equipment, such as high voltage circuit breakers, transformers, and specialized steel structures. As such, the utilities need to mitigate the impact of supply chain related delays related to the procurement of long-lead time transmission equipment by:

- Expanding bulk procurement programs to allow for more readily available stock of transmission equipment.
- Further interconnection cluster-based demand forecasting to better inform procurement efforts of transmission equipment

- Increase collaboration with interconnection customers to allow customers to procure transmission equipment in cases where it improves lead times.

Support Customers with Interconnection Education

Large volumes of resources are expected to be delayed behind Vendor/Third Party delays and Permitting delays where utilities attribute the interconnection customer as the delay resolver. This finding reveals weaknesses in interconnection customers' knowledge or ability to navigate environmental permitting, county approvals, engineering and scope changes. Utilities should work closely with their customers to proactively give them as much knowledge as possible about utility interconnection processes and procedures, and potential pitfalls their projects may face (e.g., local approvals for gen-tie routes or local permitting restrictions on generation and storage projects).

Appendix A: Glossary of Acronyms and Terms

(BLM) Bureau of Land Management: The U.S. federal agency that administers public lands, including permitting for transmission projects that cross federally managed land.

(CAISO) California Independent System Operator: A non-profit Independent System Operator serving California. It oversees the operation of California's bulk electric power system, transmission lines, and electricity market generated and transmitted by its member utilities.

Senate Bill (SB) 1174 (Hertzberg), Stats. 2022, ch. 229 / SB 1174: A California legislative act that requires large electrical corporations in California to submit annual data regarding transmission project delays and their impacts on renewable energy generation and storage resources to the California Public Utilities Commission (CPUC).

(CEQA) California Environmental Quality Act: A California law requiring state and local agencies to identify and disclose the significant environmental impacts of proposed projects and to avoid or mitigate those impacts where feasible. The CPUC conducts CEQA review before issuing permits for transmission projects.

(CPCN) Certificate of Public Convenience and Necessity: A CPUC authorization required before an electrical corporation may construct certain new transmission facilities, generally transmission lines operating at or above 200 kV.

(CPUC) California Public Utilities Commission: The California state agency that regulates investor-owned electric, natural gas, telecommunications, water, and transportation utilities. The CPUC administers the RPS program and prepares the SB 1174 assessment.

Delayed (transmission project): A transmission project whose current expected or actual in-service date (ISD) is later than its original ISD.

Delay Resolver: The party identified by a PTO as able to resolve a given transmission project's delay.

Dependent capacity / dependent resource: A renewable generation or storage resource whose ability to reach its expected in-service date depends on the completion of a delayed transmission project.

(FERC) Federal Energy Regulatory Commission: Federal agency that regulates transmission rates for electric utilities with facilities operating across state lines, reviews cost recovery mechanisms at the wholesale level, oversees reliability, and regulates wholesale power markets.

(GIS) Gas-Insulated Switchgear: Compact high-voltage switchgear that uses pressurized insulating gas rather than air, allowing substation equipment to occupy a smaller footprint.

(GW) Gigawatt & (MW) Megawatt: Units of electrical power commonly used to express the capacity of generation, storage, and transmission resources. One GW of electrical power is equal to 1,000 MW.

In development/In-development: A transmission project in any stage of development (planning, permitting, engineering, or construction) that is not yet online.

(IOU) Investor-Owned Utility: IOUs are privately owned electricity and natural gas providers and are regulated by the California Public Utilities Commission (CPUC). Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric comprise approximately 40 percent of the retail electricity supply in California.

(ISD) In-Service Date: The operational date when an energy infrastructure asset, generation facility, storage project, or transmission upgrade officially becomes active, synchronized, and delivering power or service to the electrical grid.

(kV) Kilovolt: Measurement of electrical voltage.

(NEPA) National Environmental Policy Act: A U.S. law that requires federal agencies to assess the environmental effects of their proposed actions prior to making decisions.

(PTO) Participating Transmission Owner: An entity that owns, operates, and maintains transmission facilities under the operational control of the California Independent System Operator (CAISO).

(RAS) Remedial Action Scheme: An automatic protection system designed to detect abnormal grid conditions and take corrective action (such as shedding load or generation) to maintain reliability.

Renewable Energy Generation and Storage Resources (Generation and Storage Resources): Resources that are considered for this SB 1174 assessment.

(RPS) Renewables Portfolio Standard: California's program, jointly implemented by the CPUC and the California Energy Commission (CEC), requiring load-serving entities to procure 60% of their electricity from eligible renewable resources by 2030, progressing toward 100% carbon-free electricity by 2045.

(TDF) Transmission Development Forum: Annual public forum with presentations on in-development transmission projects from CPUC jurisdictional and independent transmission owners. TDF data and presentations can be used as a reliable baseline for transmission project ISDs.

(TPD) Transmission Plan Deliverability: The capability in megawatts (MW) of the California ISO Controlled Grid as modified by transmission upgrades and additions to support the interconnection with full or partial capacity deliverability status in a specific geographic or electrical area of the ISO Controlled Grid.

(TPR) Transmission Project Review: Includes stakeholder engagement with PG&E, SCE, and SDG&E, and includes the most comprehensive data set on in-development transmission projects with a focus on project costs and permitting.

(SCADA) Supervisory Control and Data Acquisition: Industrial computer networks used by regulated utilities to monitor and control electrical grids, gas pipelines, and water systems to meet state safety, reliability, and reporting rules.

(WDAT) Wholesale Distribution Access Tariff: The tariff governing wholesale access to a utility's distribution system, including cost allocation for shared network upgrades for interconnecting resources.