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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION **RESOLUTION E-5252**
April 27, 2023

R E S O L U T I O N

Resolution E-5252 establishes the Transmission Project Review Process effective January 1, 2024.

PROPOSED OUTCOME:

- This Resolution establishes the Transmission Project Review Process to include involvement of Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E") beginning in 2024.

SAFETY CONSIDERATIONS:

- There are no safety considerations with the implementation of the Transmission Project Review Process.

ESTIMATED COST:

- Estimated Cost includes securing $1.5 million in funding from the CPUC's budget for technical consultants to implement the Transmission Project Review Process.

SUMMARY

With this Resolution, as permitted under its authority granted by the California Constitution and Public Utilities Code Sections 701, 330, 365, 314, and 581, the Commission establishes the Transmission Project Review Process ("TPR Process") for the state's investor-owned electric utilities ("IOUs" or "Utilities")[1] beginning January 1, 2024. The purpose in establishing the TPR Process is to devise a uniform process to review IOUs' capital transmission projects with the goals of providing clarity

[1] Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas & Electric Company ("SDG&E").

on projects aimed at making progress towards the state's clean energy goals, contributing more robust information for CPUC permitting processes, informing the Integrated Resource Planning program, providing useful data to help develop grid resiliency and microgrid facilities, monitoring project costs, and in general facilitating the Commission's safety and siting authority through enhanced oversight of the changing electric grid. Once established, the TPR Process will allow the Commission and all Stakeholders to receive robust data from Transmission Owners ("TO")[2] and inquire about, and provide feedback on the IOUs' historical, current, and forecast transmission projects.

The TPR Process will provide useful information to numerous programs and proceedings at the CPUC. These include but are not limited to: California Environmental Quality Act ("CEQA") review and permitting, Integrated Resource Planning ("IRP"), the Distributed Energy Resources ("DER") Action Plan, General Rate Cases ("GRC"), wildfire mitigation and recovery efforts, and the CPUC's Risk-Based Decision-Making Framework ("RDF") and Risk Assessment & Mitigation Phase ("RAMP").

For over a decade, ratepayers have been impacted by the substantial escalation in electric transmission investment under the jurisdiction of the Federal Energy Regulatory Commission ("FERC") in the California Independent System Operator Corporation ("CAISO") control area. Since 2008, California's three largest TOs' collective transmission rate base has increased by over 350% from $4.6 billion to over $21.0 billion.

For most of this time, a majority of transmission projects have received no review and approval by the CAISO[3] or the Commission,[4] and in years 2019-2021, these Utility Self-Approved ("self-approved") Projects represented over 63% (*i.e.*, $4.2 billion) of the

[2] Unless otherwise indicated, "Transmission Owner" ("TO"), "Investor-Owned Utility" ("IOU"), and "Utility" are used interchangeably in this Resolution.

[3] The CAISO's FERC Tariff does not currently require review and approval of projects that do not expand the capacity of the CAISO-controlled transmission grid or which do so only incidentally.

[4] As a result of negotiations in PG&E's and SCE's FERC TO rate cases, and as described later in this Resolution, robust, but temporary, stakeholder processes were established in 2020 to provide transmission project data, afford discovery opportunities, and convene stakeholder meetings on a semi-annual basis. These two processes, while different in some ways, are the predecessor of the Transmission Project Review Process proposed in this Resolution. While not as comprehensive as the PG&E and SCE processes, SDG&E also established in its last rate case at FERC, a transmission project evaluation process, which includes an annual release of transmission project data to intervenors in SDG&E's TO rate case, an inquiry period, and an annual Stakeholder meeting. PG&E's and SCE's processes are currently set to expire at the end of 2023.

$6.6 billion of capital additions added to the three TOs' transmission rate bases.[5] Largely driven by the costs of capital projects, since 2016, the annual total of the three TOs' revenue requirements in their rate cases at FERC have increased by over 85% from $3.1 billion in 2016 to a forecast of nearly $5.8 billion in 2023.

While transmission project costs are already a significant burden on ratepayers, in May 2022, CAISO released its *20 Year Transmission Outlook,* estimating that in the next two decades, $30.5 billion[6] of investment in new transmission capacity on the high voltage transmission system will be needed to meet the state's clean energy goals.[7]

The majority of utility transmission projects are currently self-approved projects, which lack transparency of their planning, prioritization, budgeting, and implementation. With the anticipation of the aforementioned large expansion of the transmission grid, it is more important than ever that transparency of transmission projects occur to protect ratepayers, ensure the Commission has the ability to track how projects best meet needs related to interconnection of renewable energy resources, CPUC permitting processes, risk and safety assessments, and more broadly address the integrated resource planning needed to meet the state's clean energy goals and the changing electric grid. The TPR Process will provide the Commission and all Stakeholders the opportunity to receive data and engage with the TOs to better understand planning assumptions and needs, and the determined transmission solutions before and during project construction.

The TPR Process will provide the Commission and all Stakeholders semi-annually with current, specific, comprehensive, and system-wide transmission data for projects with capital additions to rate base in the last five years and forecasted or actual capital expenditures in the current year and future four years. These will include specific projects, as well as programmatic buckets or blanket program categories (collectively "Projects"), that are CAISO-approved or Utility Self-Approved, as well as transmission network upgrades needed for generator interconnections. Projects will be included if they are expected to total $1 million or more in capital costs. Additionally, the TPR Process will provide the CPUC and all Stakeholders with the TOs' current asset management procedure documents relied on for identifying, proposing, authorizing, planning, prioritizing, budgeting, and executing Projects. The CPUC and Stakeholders

[5] These numbers are based on the utilities' responses in July 2022 to an Energy Division data request, which asked the utilities to provide the costs of CAISO- and self-approved projects for the previous decade and forecasts for the next five years.

[6] California ISO, *20 Year Transmission Outlook*, May 2022 at 3.

[7] The high voltage system is the portion of the transmission grid that is 200 kilovolts ("kV") or greater. This estimated $30.5 billion in new transmission build-out does not include costs for the portion of the transmission system that is lower than 200 kV. These lower voltages currently comprise approximately 40% of the costs of operating the CAISO controlled transmission grid.

will have the opportunity to provide questions and comments, to which the IOUs will be required to provide written responses. Finally, each IOU will convene two Stakeholder Meetings with the CPUC and Stakeholders on an established schedule, to discuss Project data, Procedures, Project alternatives, and other identified issues.

BACKGROUND

The TPR Process is necessary for the Commission and Stakeholders to understand the TOs' planning assumptions, determination and prioritization of needs, and the processes leading to transmission solutions and network upgrades. California ratepayers have been burdened by the escalation in costs related to Utility Self-Approved transmission projects; transparent and reliable data have been elusive; current stakeholder processes are inconsistent and temporary; and generator interconnection-related network upgrades are becoming more frequent and costly.

Jurisdiction And Legal Authority of the Commission

The Commission enforces a variety of federal and state laws that impose utility safety requirements and exercises broad oversight of utility infrastructure and operations. Pursuant to Article XII, Sections one through six of the California Constitution, the Commission has broad authority to regulate utilities, including the Commission's ability to "fix rates, establish rules...and establish its own procedures" for all public utilities subject to its jurisdiction.[8] Specifically, Article XII, Section 3 of the California Constitution provides that "the production, generation, transmission, or furnishing of heat, light, water, power" fall under the jurisdiction of the California legislature. California Public Utilities statutes are enforced by the Commission.[9]

The California Legislature enacted the Public Utilities Act which authorized the Commission to "supervise and regulate every public utility in the State" and to do all things "which are necessary and convenient in the exercise of such power and jurisdiction" whether specifically designated in the Public Utilities Act or in addition thereto.[10] Though the IOUs transferred operational control of transmission facilities to the CAISO in 1998, the IOUs remain transmission owners subject to the Commission's authority over public safety and siting.[11] Further, pursuant to Public Utilities Code

[8] *Davis v. Southern California Edison Co.* (2015) 236 Cal.App.4th 619, 636 ("'[t]he Commission [(PUC)] is a state agency of constitutional origin with far-reaching duties, functions and powers'…. The Constitution confers broad authority on the commission to regulate utilities….")

[9] *See S. California Edison Co. v. Pub. Utilities Com.*, (2014) 227 Cal.App.4th 172, 190.

[10] Pub. Util. Code § 701.

[11] 16 U.S.C. § 824; Pub. Util. Code §§ 330, 365.

Section 451, the Commission has broad authority to regulate public utility services and infrastructure as necessary to ensure they are operated "as are necessary to promote the safety, health, comfort, and convenience" of Californians.

The Commission has broad authority to require information from public utilities.[12] The Commission has the authority to "at any time, inspect the accounts, books, papers, and documents of any public utility."[13] The Commission may "examine under oath any officer, agent, or employee of a public utility in relation to its business and affairs."[14] Public utilities also have a duty to furnish information to the Commission. "Every public utility shall furnish to the commission in such form and detail as the commission prescribes all tabulations, computations, and all other information required by it to carry into effect any of the provisions of this part, and shall make specific answers to all questions submitted by the commission."[15]

Furthermore, "[e]very public utility receiving from the commission any blanks with directions to fill them shall answer fully and correctly each question propounded therein, and if it is unable to answer any question, it shall give a good and sufficient reason for such failure."[16] This Resolution establishes a process that will provide transparent information about the IOUs' transmission infrastructure and the various ways they impact meeting the Commission's safety, clean energy, and reliability goals. This Resolution does not invoke any ratemaking authority over transmission assets, and the Commission is not exercising any authority to set transmission rates or conduct any transmission planning.[17]

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[12] *See e.g.* Pub. Util. Code §§ 311, 314, 581, 582, 584, and 701.

[13] Pub. Util. Code § 314(a).

[14] *Id*.

[15] Pub. Util. Code § 581.

[16] *Id*.

[17] The CPUC identifies five main steps from the beginning of the transmission planning process to rate recovery. Determination and prioritization of assumptions, needs, and transmission solutions are the main components of transmission planning, whether projects are CAISO-approved or self-approved. Stages four and five are respectively project implementation and the recovery of costs for capital additions in TO rate cases at FERC. Like PG&E's Stakeholder Transmission Asset Review ("STAR") Process and SCE's Stakeholder Review Process ("SRP"), the TPR Process will occur after the transmission planning stages and will address projects before and during their construction, with an opportunity to have visibility of recently completed projects as well. The TPR Process is not part of transmission planning or rate recovery stages, which both fall under FERC's jurisdiction.

Difficulty Obtaining Transparency and Reliable Data on Transmission Projects

As explained below, most of the escalation in costs related to the IOUs' rate bases is attributable to Utility Self-Approved Projects. Temporary stakeholder processes revealed that the IOUs' procedures for planning and prioritizing projects are inadequate and often *ad hoc*. Further, recordkeeping on such projects is often scattered throughout unintegrated IT and other recordkeeping systems.

While the Commission acknowledges that improvements in the IOUs' data and recordkeeping have occurred during recent stakeholder processes, data transparency and reliability must continue to improve to enable the Utilities to appropriately manage their systems, for the Commission to perform its safety and siting oversight, and for ratepayers and other Stakeholders to receive timely, accurate, and useful information on transmission projects.

Current Stakeholder Processes are Inconsistent and Temporary

As part of the efforts to remedy the lack of transparency of transmission projects, the Commission and other intervening parties negotiated PG&E's Stakeholder Transmission Asset Review ("STAR") Process, SCE's Stakeholder Review Process ("SRP"), and SDG&E's Evaluation of Forecast Period Capital Additions ("Project Evaluation") in their most recent rate cases at FERC.[18] The STAR Process, SRP, and Project Evaluation are all temporary, and the two more comprehensive processes (*i.e.*, STAR Process and SRP) are not fully consistent in the information that they provide.

However, similarities in the processes require PG&E and SCE to report semi-annually to Stakeholders on over 60 data fields related to each transmission project's description, status, costs, CAISO or utility self-approval, and Commission permitting status (if applicable). Data are provided for all Projects that have actual or forecast costs of $1 million or greater. Projects include any capital additions for at least the prior four years and projects with any forecast capital expenditures in the current or next five years. The data, the opportunity to engage in discovery on projects and procedures, and stakeholder meetings all help the Commission and Stakeholders to understand recent transmission development trends, current transmission projects, and priorities for forecast transmission projects.

While the STAR Process and SRP signal progress in achieving transparency of PG&E's and SCE's transmission Projects, these processes are set to expire at the end of

[18] See Pacific Gas and Electric Company Transmission Owner Tariff Rate Filing, Pac. Gas & Elec. Co., FERC Docket No. ER19-13-000 (filed Oct. 1, 2018), Appendix IX; Southern California Edison Company Transmission Owner Tariff Rate Filing, S. Cal. Edison Co., FERC Docket No. ER19-1553 (filed Apr. 11, 2019); San Diego Gas & Electric Company Transmission Owner Tariff Rate Filing, San Diego Gas & Electric Co., FERC Docket No. ER19-221 (filed Oct. 15, 2019).

2023. Further, as the STAR Process and SRP were negotiated separately within the two respective TO rate cases, the two processes are not fully consistent, and SDG&E's Project Evaluation is far less comprehensive. While the STAR Process and SRP are temporary and inconsistent, they have provided useful information for the Commission and Stakeholders, and savings for ratepayers. Important lessons learned in these processes inform this Resolution.

Escalation of Costs on Transmission Projects

In the last decade ratepayers have been impacted by the substantial escalation in electric transmission investment in the CAISO control area. For every dollar added to a Utility's rate base, ratepayers pay that dollar multiple times over the life of a capital asset. Since 2008, the three IOUs' collective transmission rate base has increased by over 350% from $4.6 billion to over $21.0 billion. Ratepayers are further disadvantaged by the fact that a majority of the Projects receive no review and approval by the CAISO or the Commission, and in years 2019-2021, Utility Self-Approved Projects represented over 63% (*i.e.*, $4.2 billion) of the $6.6 billion of capital additions to rate base. This escalation in transmission capital spending is having an increasing impact on consumers in TO rate cases at FERC, as reflected in the annual transmission revenue requirements, which have collectively increased by over 80% since 2016, from $3.1 billion to a forecast $5.6 billion in 2023.

While these costs already burden ratepayers, CAISO's *20 Year Transmission Outlook* provides added clarity on the importance of the Commission and Stakeholders having transparency of how projects are being planned, prioritized and implemented in the CAISO region. CAISO estimates that in the next 20 years, $30.5 billion of new transmission capacity will be needed to meet the state's clean energy goals. This is a massive expansion of the existing grid, and most of these costs will be recovered from ratepayers multiple times over the depreciable lives of these transmission assets.

Furthermore, this $30.5 billion is the CAISO's estimate for expanding just the high voltage (*i.e.*, greater than 200 kV) portion of the transmission grid. While these capacity expansion projects should receive stakeholder review through the CAISO's Transmission Planning Process, three important facts remain:

First, as explained above, a majority of transmission projects are currently self-approved repair or replacement projects, the future costs of which would not be included in this $30.5 billion estimate. Therefore, projects repairing or replacing assets already in today's grid, and eventually repairing and replacing the infrastructure included in the 20 Year Outlook's build-out, could be unreviewed and self-approved. Second, aside from the continued billions of dollars spent on self-approved repair and replacement projects, approximately 40% of the costs to operate the current CAISO controlled transmission grid are for the portion of the transmission grid that operates below 200kV. Therefore, capacity expansion that would likely be needed on these lower voltage lines is also not included in the CAISO's $30.5 billion estimate. Because this $30.5 billion includes neither self-approved projects nor added capacity build-out of lower voltage transmission, efforts to encourage cost-effective and efficient investment are essential, and ensuring the Commission maintains its ability to exercise its oversight authority is imperative.

Finally, the TPR Process will provide important transparency and understanding of transmission investments before the utilities file for cost recovery at FERC. While the TOs often reference intervenors' ability, if needed, to challenge project costs in rate cases at FERC, the lack of transparency in the planning stages of Utility Self-Approved Projects has resulted in ratepayers learning about projects after they are determined or are being implemented – too late to evaluate their development or propose alternatives.

Network Upgrades Needed for Interconnection of Renewable Resources

With the proliferation of renewable energy resources in California, the large build-out described in the CAISO's *20 Year Transmission Outlook*, and the increasing need for interconnection-related transmission upgrades, renewable generators have a significant stake in the development of transmission projects.

In 2006, the Commission implemented Assembly Bill 970 in Decision 06-09-003, which ordered all three IOUs to provide basic information on transmission projects related to generator interconnection projects ("AB 970 Reports"). While SCE has integrated its AB 970 Report information into the SRP data, PG&E has continued providing the more limited quarterly AB 970 Report in addition to the semi-annual STAR Process data.

With the current and future development of renewable generation; the congestion of the CAISO's generator interconnection queue; and the increasing numbers, costs, and complexity related to interconnection-related network upgrades, generators have expressed to the Commission that the AB 970 Reports fall short of the level of information needed on these network upgrades. It is also clear that more careful coordination between interconnection-related upgrades and transmission projects approved in the CAISO's Transmission Planning Process ("TPP") is necessary to ensure the most efficient and cost-effective solutions for the transmission grid. Further, in the CAISO, unlike in other independent system operator ("ISO") or regional transmission organization ("RTO") areas of the country, the generators who trigger network upgrades are typically reimbursed in full for the costs of network upgrades that they initially finance, with the full costs of the upgrades ultimately falling on ratepayers. Therefore, it is important to both generators and ratepayers for the TPR Process to provide Stakeholders with transparency of transmission network upgrades.

Numerous Commission Programs and Proceedings Benefit from Robust Transmission Data.

The TPR Process will benefit several programs and proceedings at the Commission.

California Environmental Quality Act

The Infrastructure Permitting and California Environmental Quality Act ("CEQA") Section of the Energy Division conducts and manages environmental reviews of transmission infrastructure projects that are required to file for either a Certificate of Public Convenience and Necessity ("CPCN") or a Permit to Construct ("PTC") (collectively "Permits") at the CPUC.

Investor-owned utilities are required to obtain a permit from the CPUC for construction of certain specified infrastructure listed under Public Utilities ("PU") Code sections 1001 et seq. The CPUC reviews permit applications under two concurrent processes: (1) an environmental review pursuant to CEQA for both CPCNs and PTCs, and (2) the review of project need and costs for CPCNs pursuant to PU Code sections 1001 et seq. and General Order 131-D for CPCNs and PTCs.

PU Code Section 1002.3 states:

> In considering an application for a certificate for an electric transmission facility…, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, … and other demand reduction resources.

PU Code Section 1005.5(a) continues:

> Whenever the commission issues to an electrical … corporation a certificate authorizing the new construction of any addition to or extension of the corporation's plant estimated to cost greater than fifty million dollars ($50,000,000), the commission shall specify in the certificate a maximum cost determined to be reasonable and prudent for the facility.

The extensive data on past, current and future transmission projects provided in the TPR Process will contribute significantly to the requirements for determining the cost and need of a project in these CPUC permitting proceedings, and to the environmental review performed by the CEQA Section.

Integrated Resource Planning

The Integrated Resource Planning ("IRP") proceeding considers all of the Commission's electric procurement policies and programs and ensures California has a safe, reliable, and cost-effective electricity supply that meets the State's greenhouse gas reduction goals. To evaluate need, IRP takes a 10-year-ahead look at the electricity system, also looking out to 2045.

The assumptions used in the IRP's analyses are developed each IRP cycle with stakeholder involvement. Coordination with the Energy Commission and the California Independent System Operator is done according to an interagency agreement, particularly regarding the demand forecast assumptions to use in planning. The assumptions are updated regularly to incorporate changes in the resource mix and revisions to state policies, like resource costs, potential, and operations. Just as IRP includes regular stakeholder input, the TPR Process will provide the continued opportunity for the CPUC and other Stakeholders to receive data and ask questions regarding transmission projects needed to realize the desired outcomes in the IRP Proceeding.

Distributed Energy Resources Action Plan

The goal of the Distributed Energy Resources ("DER") Action Plan is to ensure that DER policy implementation in support of SB 100[19] and California's energy and climate goals are coordinated across proceedings related to grid planning, affordability, load flexibility, market integration, and customer programs. Ultimately, this DER Action Plan 2.0 seeks to align the CPUC's vision and actions to maximize ratepayer and societal value of an anticipated high-DER future.

The Grid Infrastructure Track is focused on CPUC actions to guide utility infrastructure planning and operations to make the most of existing and future infrastructure and maximize the value to ratepayers of DERs interconnected to the electric grid. The CPUC will guide the utilities to modernize the electric grid for a high

[19] In 2018, the California Legislature enacted Senate Bill 100, "The 100 Percent Clean Energy Act of 2018", which sets a 2045 goal of powering all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources; and requires the California Energy Commission, California Public Utilities Commission and California Air Resources Board to use programs under existing laws to achieve 100 percent clean electricity.

DER future that best enables swift evolution of grid capabilities and operations to integrate higher levels of DER to meet the State's 100 percent clean energy goals.

The Market Integration Track of the DER Action Plan focuses on the efficient integration of DER into wholesale markets to advance state goals of greenhouse gas reduction, renewable integration, and grid optimization. One of the potential services that energy storage can provide is deferral of transmission development. Access to timely transmission data will aid the analysis of transmission deferral opportunities with DER as non-wires alternatives.

The DER Action Plan further works to ensure utility infrastructure business processes, including planning, all-source resource acquisition, and operation are transparent, responsive to local and tribal conditions and community needs, and seamlessly integrate cost-effective distributed energy resources. Additionally, the DER Action Plan establishes that utility operations should continuously improve interconnection performance, leading to greater transparency, cybersecurity, speed, and cost certainty. Finally, it is intended that utilities integrate the anticipated impacts of electrification into distribution planning to maximize public benefits, minimize costs, and optimize deployment of complimentary and supporting infrastructure and distributed energy resources.

The transmission assets included in the TPR Process will enable more holistic evaluation of the interplay between the distribution and transmission systems to most efficiently and cost-effectively achieve California's clean energy goals.

General Rate Cases

The General Rate Cases ("GRC") for electric utilities at the CPUC set the revenue requirements and rates that the utilities collect for the distribution and generation assets that fall under the CPUC's jurisdiction. However, there is interplay between the distribution facilities in the GRC and transmission assets, as well as overlap of important issues, such as the interconnection of renewable energy resources and issues related to wildfire mitigation and recovery. The scope and need for projects at the transmission and distribution levels may inform each other. The TPR Process will provide this larger context of transmission projects and will address overlapping issues that are potentially useful in GRC proceedings.

Wildfire Mitigation Plans

Wildfire safety crosses jurisdictional lines and is an issue to be addressed on both the distribution and transmission portions of the grid. Since 2019, California utilities have filed Wildfire Mitigation Plans ("WMP") at the CPUC and now with the Office of

Energy Infrastructure Safety ("Energy Safety") in the California Natural Resources Agency. The WMPs now require approval by both the CPUC and Energy Safety. The TPR Process will include fire-related data, including whether projects are in high fire threat areas or are components of the approved WMP. It is important to be able to effectively implement projects for safety, reliability, and resiliency, and to ensure such projects are implemented in a cost-effective manner. As the WMPs include work on both the distribution and transmission systems, the TPR Process provides useful information to the CPUC, Energy Safety, and Stakeholders on fire-related transmission projects.

Risk-Based Decision-Making Framework and Risk Assessment and Mitigation Phase

In Decision 18-12-014, the CPUC adopted its Risk-Based Decision-Making Framework ("RDF"), which since that time has required IOUs to employ a Multi-Attribute Value Function ("MAVF") approach for assessing risk. A recent Proposed Decision in Rulemaking 20-07-013 seeks to remedy the fact that "unitless Risk Scores required in the MAVF approach have made it difficult to interpret IOUs' RAMP [Risk Assessment and Mitigation Phase] filings and have not adequately supported transparency"[20] by adopting a Cost-Benefit Approach that among other things, requires standardized dollar valuations of Safety and Electric Reliability Consequences from Risk Events. A Cost-Benefit Approach would be used to determine whether Benefits or Mitigation Risk Reduction, expressed in dollars, exceed Costs without having to rank mitigations against one another. The new approach would require PG&E, SCE, and SDG&E to implement the modified RDF to assess and rank risks and mitigations in their RAMP filings. For transmission Stakeholders to have a clear sense of the assumptions used in planning, prioritizing, and approving transmission projects, the TPR Process will include information on whether and how each transmission owner has applied the most current RDF to each project.

NOTICE

The Draft Resolution was served on service lists in the following CPUC proceedings: A.19-08-013, A.21-06-021, A.22-05-016, I.00-11-001, R.20-05-003, and R.20-07-013 on December 13, 2022.

[20] Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots, Finding of Fact #2, p. 49. (November 3, 2022)

DISCUSSION

With this Resolution, the Commission is establishing the Transmission Project Review Process for the CPUC and Stakeholders to better understand, inquire about, and provide input on, the three IOUs' electric transmission projects and transmission network upgrades. The Resolution will inform the CPUC's ratepayer advocacy, further California's energy policy goals, support the CPUC's risk and safety assessment requirements, and facilitate engagement by Stakeholders with the Utilities around their transmission projects and interconnection-related network upgrades. As explained in greater detail in Attachment A to this Resolution, the TPR Process will include:

- Robust, consistent, and ongoing data via Project Spreadsheets, Procedures, and Authorization Documents to ensure sufficient transparency of Utilities' transmission Projects, including generator interconnection-related network upgrades. The TPR Process will help Stakeholders understand the Utilities' identification, authorization, planning, prioritization, budgeting, and implementation processes related to transmission Projects;
- Opportunities for the CPUC and all transmission and generator interconnection Stakeholders to engage with the Utilities through inquiry and comments, and to receive timely written responses from the Utilities; and
- Stakeholder meetings to further understand the bases for each Utility's Projects and Procedures, and to discuss CPUC- and Stakeholder-identified topics related to specific Projects, Project categories, and Procedures.

As explained in greater detail in Section 2 of Attachment A and in Attachment B to this Resolution, the expansive information will include: clear descriptions of Projects, forecast and actual costs, progress and status of each Project, and permitting status at the CPUC. Projects are included in the TPR Process regardless of whether they are Projects reviewed and approved in the CAISO's Transmission Planning Process or Generator Interconnection and Deliverability Allocation Procedures (GIDAP), or are Utility Self-Approved Projects. However, while the CPUC and Stakeholders have a keen interest in monitoring the progress and costs of CAISO-approved Projects, the TPR Process is not a venue for reconsidering the approval of such Projects. The primary focus of the TPR Process is on the nearly two-thirds of the Utilities' transmission capital investments that are not reviewed and approved by the CAISO. The TPR Process will also include information on the consideration of Project alternatives.

As described in Attachment C to this Resolution, the timelines for the three IOUs are staggered by a month to enable the CPUC and Stakeholders to engage meaningfully with all three Utilities in the TPR Process.

With greater detail in the above-mentioned Attachments, below is a brief description of the main components of the Transmission Project Review Process.

STAKEHOLDERS

A Stakeholder is:

- a CAISO market participant;
- an electric utility regulatory agency other than the CPUC within California;
- an interconnection customer that has submitted an interconnection request to the ISO under the ISO's Large Generator Interconnection Procedures or Small Generator Interconnection Procedures;
- a developer having a pending or potential proposal for development of a Generating Facility or transmission addition, upgrade or facility and who is performing studies in contemplation of filing an Interconnection Request or submitting an infrastructure project through the ISO's Transmission Planning Process;
- a not-for-profit organization representing consumer regulatory or environmental interests before local regulatory authorities or federal regulatory agencies; or
- an entity providing consulting services or support to a party eligible to receive confidential information according to the criteria described above.

TRANSMISSION PROJECTS AND DATA

Described in more detail in Attachment A to this Resolution, a Project in the TPR Process is any FERC-jurisdictional electric transmission project with actual or forecast costs of $1 million or more, which a Utility has included or intends to include in its FERC-jurisdictional electric transmission rate base, including both CAISO and Non-CAISO Projects. A Project would include all of the components of a specifically identified Project, as well as programmatic buckets or blanket program work categories, which include projects that are categorized as part of an identified category with other similar projects.

The Project data are presented in the Project Spreadsheet ("Spreadsheet"), which is provided to the CPUC and Stakeholders semi-annually and shall contain up-to-date data on all Projects with actual or forecast costs of $1 million or more, regardless of whether they were included in the CAISO's Transmission Planning Process. Sortable Project-specific data will be provided for all electric transmission Projects that had capital expenditures in the prior five calendar years or actual or forecast capital expenditures for the current year or the next four-year period. The Spreadsheet will include nearly 70 populated data fields for each transmission Project required by the TPR Process. The data fields are described in detail in Attachment B to this Resolution.

There will be both a public version and a confidential version of each semi-annual Project Spreadsheet. The public version will be sent to a distribution list and made available on each Utility's website with confidential data and Critical Energy Infrastructure Information CEII redacted.

Information that is confidential or designated as CEII shall be provided to certain Stakeholders pursuant to CPUC and FERC limitations. Access to the confidential data will require a signed non-disclosure agreement. Each Utility will submit its proposed non-disclosure agreement to Energy Division for approval via Tier 2 advice letter within 75 days of the approval of Resolution E-5252. Further details on format of and accessibility to data will be discussed in a Workshop, which will include numerous other issues, in Summer 2023.

Procedures refer to those procedures, standards, strategies, processes, or any documents created by the Utility to identify, propose, authorize, plan, prioritize, budget, and implement a Project included in the TPR Process Project Spreadsheet.

Authorization Documents are those internal Utility documents used at any stage of a Project for management authorization or re-authorization of the Project.

The data in the Project Spreadsheet, Procedures, and Authorization Documents should enable the CPUC and Stakeholders to understand the IOU's processes for identifying, proposing, authorizing, planning, prioritizing, budgeting, and implementing Projects.

INQUIRY AND COMMENT PERIOD

As part of the TPR Process, the CPUC and Stakeholders may submit information requests and comments within 45 calendar days beginning on the day following the production of the semi-annual Project Spreadsheet, Procedures, and Authorization documents. The CPUC and Stakeholders may also submit information requests and/or comments within 15 calendar days beginning on the day following a Stakeholder meeting. The Utility will exercise best efforts to respond to the information requests and comments within 15 business days after the CPUC or a Stakeholder submits them to the Utility.

Should the Utility not be able to respond fully within 15 business days, the Utility shall notify in writing the CPUC and all Stakeholders within ten business days and include an explanation of the delay. Delays may affect subsequent dates in the TPR Process.

The scope of the information requests is explained in greater detail in Section 3 of Attachment A to this Resolution.

STAKEHOLDER MEETINGS

Each Utility will annually host no fewer than two Stakeholder meetings. The first Stakeholder meeting in a calendar year will include an assessment of the previous year's transmission projects and a more in-depth overview of objectives, assumptions, and deliverables for the coming year, as well as the opportunity for Stakeholders to suggest new projects or project alternatives. Both Stakeholder meetings will also focus on the CPUC's and Stakeholders' questions and comments related to Projects and Procedures. No fewer than 15 days before a Stakeholder meeting, Stakeholders and the CPUC will be able to provide agenda items to the Utility, which will include those topics and will have subject matter experts present who can respond to comments, questions, and issues raised by the CPUC and Stakeholders.

USE OF INFORMATION OBTAINED IN THE TPR PROCESS

It is the intention that the information developed in the TPR Process will be useful for many entities in numerous ways. Input from the CPUC and Stakeholders may provide useful information for the CAISO and the TOs in their determination of the most efficient and cost-effective Projects to build to address reliability, economic, and public policy concerns. Also, as mentioned above, the transparency of, and robust data related to, transmission Projects and network upgrades will provide additional information to CPUC programs and proceedings, including CEQA review and permitting, Integrated Resource Planning, and wildfire mitigation efforts.

Beyond the usefulness of the information mentioned above, notwithstanding any Critical Energy Infrastructure and Information or other confidentiality restrictions, any information obtained in the TPR Process may be used without limitation in other fora and proceedings, including those at the CPUC, FERC, CAISO, Department of Energy, and elsewhere.[21]

DISPUTE RESOLUTION

In the event a substantive or procedural dispute arises regarding the implementation of the TPR Process that is not easily resolved, the disputing party may file a "Notice of Dispute" with the CPUC's Executive Director or designee within ten (10) days after the parties reach an impasse. The Executive Director or designee will review the disputed issue and make a determination resolving the dispute within 30 days of receiving the Notice of Dispute. The determination of the Executive Director or designee shall be served on the filer and identified Stakeholders. The Executive Director or designee's determination shall be final.

COMMENTS

Public Utilities Code section 311(g)(1) provides that the Draft Resolution was subject to at least 30 days public review and comment prior to a vote of the Commission. Accordingly, Draft Resolution E-5252 was mailed for comments on December 13, 2022, to service lists in the following CPUC proceedings: A.19-08-013, A.21-06-021, A.22-05-016, I.00-11-001, R.20-05-003, and R.20-07-013.
The deadline by which all comments on the Draft Resolution were to be received by the Energy Division was extended per joint request by the Utilities from January 12, 2023 to February 13, 2023.

Comments on Resolution E-5252

Energy Division received 16 sets of comments on Draft Resolution E-5252, providing general comments, raising legal and jurisdictional questions, and making both procedural and substantive recommendations for the TPR Process. A majority of the commenters expressed support for establishing the TPR Process, recognizing the benefits of increasing transparency of transmission projects[22]. A smaller number of

[21] The CAISO has its own non-disclosure agreements and confidentiality rules for accessing CAISO data that are unaffected by the TPR Process.

[22] Comments of the California Energy Storage Alliance on Draft Resolution E-5252: Establishing the Transmission Project Review Process ("CESA Comments") (February 13, 2023); Comments of Redwood Coast Energy Authority on Draft Resolution E-5252 ("RCEA Comments") (February 13, 2023); Comments

Footnote continued on next page

commenters opposed establishing the TPR Process[23], while the CAISO filed mostly neutral comments seeking clarification of how the TPR Process will function in relation to its Transmission Planning Process and Transmission Development Forum.[24]

Legal Authority

In it its comments, the Center for Energy Efficiency and Renewable Technologies ("CEERT") raises the issue of whether the CPUC has the authority to use the resolution process to establish the TPR Process.[25] CEERT asserts that pursuant to Public Utilities ("PU") Code section 1708, Resolution E-5252 improperly modifies or amends prior CPUC decisions. The prior decisions CEERT cites include D.06-09-003 which established the current AB 970 reporting requirement, D.20-11-027 which exempted PG&E from filing an AB 970 report, and D.21-03-010 which exempted SCE from filing an AB 970 report.[26] CEERT alleges the exemptions to AB 970 reporting requirements were conditioned "'until and unless' the FERC reporting requirements 'expire or are reduced in scope' compared to the AB 970 reports."[27]

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of American Clean Power – California on Draft Resolution E-5252 ("ACP Comments") (February 13, 2023); Comments of the Bay Area Municipal Transmission Group in Response to Draft Staff Resolution E-5252 from the Energy Division ("BAMx Comments") (February 13, 2023); Comments of the California Farm Bureau Federation on the Resolution E-5252 Establishes the Transmission Project Review Process Effective January 1, 2024 ("CFBF Comments") (February 13, 2023); Solar Energy Industries Association Comments on Draft Resolution E-5252 ("SEIA Comments") (February 13, 2023); Large-scale Solar Association Comments on Draft Resolution E-5252 ("LSA Comments") (February 13, 2023); Comments of the Northern California Power Agency ("NCPA Comments") (February 13, 2023); Comments of the Public Advocates Office on the Draft Resolution Establishing the Transmission Project Review Process ("Cal Advocates Comments") (February 13, 2023); Supportive Comments of the California Department of Water Resources State Water Project ("DWR Comments") (February 13, 2023); Comments of the Transmission Agency of Northern California on Draft Resolution E-5252 ("TANC Comments") (February 13, 2023).

[23] East Bay Community Energy Comments ("EBCE Comments") (February 13, 2023); Joint Comments by Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company ("Utilities Comments") (February 13, 2023); Comments of the Independent Energy Producers Association on Draft Resolution E-5252 ("IEP Comments") (February 13, 2023); Comments of the Center for Energy Efficiency and Renewable Technologies ("CEERT Comments") (February 13, 2023).

[24] California Independent System Operator Corporation Comments on Draft Resolution E-5252 ("CAISO Comments") (February 13, 2023).

[25] CEERT Comments, pp. 4-5.

[26] CEERT Comments, p. 3.

[27] CEERT Comments, p. 7 (citing Commission Decisions 20-11-027 and 21-03-010). Referencing FERC Reporting Requirements in PG&E's STAR Process and SCE's SRP.

Further, CEERT argues that establishing the TPR Process through an informal resolution process does not provide sufficient notice and opportunity to be heard per constitutional due process requirements;[28] the TPR Resolution does not cite any decision by the Commission directing Energy Division to establish the TPR Process by resolution;[29] and that the Resolution is not based on evidence adduced before the Commission in any formal proceeding on these issues, arguing that without a formal proceeding and evidentiary record on these issues, the Commission is prejudging outcomes on any transmission investment, which is "wholly arbitrary and highly prejudicial."[30]

Finally, CEERT states that because there is no docket card for an informal resolution, the information tracking is more difficult[31] and believes that the TPR Process should be established via an Order Instituting Investigation or Rulemaking.[32]

Public Utilities Code section 1708 pertains to recission and amendment of a prior order or decision. Contrary to CEERT's assertions, Resolution E-5252 does not amend or modify Commission Decisions 20-11-027 or 21-03-010, as it is not inconsistent with the Conclusions of Law or Orders in either decision. Those decisions exempted PG&E and SCE from the AB 970 quarterly reporting requirements until either 1) the reporting requirements under their respective STAR Process or Stakeholder Review Process expire or 2) are reduced in scope to those below AB 970 quarterly reporting requirements.[33] The TPR Process does not trigger either of these conditions or modify these prior decisions.[34] The TPR Process is an information gathering and review process that does not result in any binding determination or disposition with respect to any transmission project investment or selection.

Regarding CEERT's assertion that a resolution process is not sufficient, a formal proceeding and hearing are not required to adopt the TPR Process. Even in formal proceedings before the Commission, there is no constitutional requirement that the Commission hold an evidentiary hearing and no provision of law or Commission rule

[28] CEERT Comments, p. 8.

[29] CEERT Comments, pp. 8-9.

[30] CEERT Comments, p. 9.

[31] CEERT Comments, pp. 5, 9-10, 12.

[32] CEERT Comments, pp. 2, 11.

[33] D.20-11-027 pp. 8-9; D.21-03-010 at pp. 4-5. If either of those conditions are met, then the utility shall notify the Commission by Tier 1 Advice Letter. D.20-11-027 at p. 9; D.21-03-010 at p. 5. PG&E did this when it filed Advice Letter 6304-E on August 23, 2021, reinstating its AB 970 Reporting requirement as of October 1, 2021.

[34] However, if either of those conditions are met, the decisions provide a procedure to address a modification by requiring the utility to notify the Commission by Tier 1 Advice Letter. D.20-11-027 at p. 9; D.21-03-010 at p. 5.

automatically entitles the right to an evidentiary hearing.[35] A fundamental requirement of due process is the opportunity to be heard "at a meaningful time and in a meaningful manner."[36] The initial deadline to provide comments to the draft resolution was extended to allow additional time to submit comments and 16 sets of comments were received. The resolution process, although informal, does provide the requisite notice, opportunity to be heard, and dispute resolution by an impartial decisionmaker should a dispute arise in the TPR Process.

Jurisdiction

The Utilities' Comments correctly assert that "FERC has exclusive jurisdiction over transmission planning and rates."[37] Further, the Utilities accurately note that "[i]f there was a dispute as to whether a project was prudent and reasonable, that could only be resolved at FERC, and not by the Energy Division."[38] They also comment that the Dispute Resolution section in the TPR Process Description should only address procedural disputes in implementing the TPR Process and should not be resolved by Energy Division.[39] LSA shares similar concerns that "substantive disputes about the worthiness of the projects" should be handled in the appropriate proceedings to avoid duplicating efforts.[40] The Utilities also comment that the CPUC lacks jurisdiction to delegate its authority to inspect utility records and documents to unspecified stakeholders.

The TPR Process Resolution pertains to information regarding already-planned projects and does not assume any binding authority related to transmission planning or ratesetting for projects included in the TPR Process.

Regarding the Dispute Resolution provisions in the Resolution, this section was modified to clarify that determinations in the dispute resolution procedures relate only to issues arising between TPR Process participants that relate solely to the implementation of the TPR Process itself. Further, any matters that cannot be resolved

[35] *Wood v. Pub. Utilities Comm'n* (1971) 4 Cal.3d 288, at p. 292; Pub. Util. Code § 1701, et seq..

[36] *Mathews v. Eldridge* (1976) 424 U.S. 319, at p. 333. Additionally, under the state due process analysis, an aggrieved party must "identify a statutorily conferred benefit or interest of which he or she has been deprived to trigger procedural due process under the California Constitution…." (*Ryan v. California Interscholastic Fed'n-San Diego Section* (2001) 94 Cal. App. 4th 1048, at p. 1071.) CEERT has not identified any such statutorily conferred benefit or interest.

[37] Utilities Comments, p.4.

[38] Utilities Comments, p. 14.

[39] Utilities Comments, p. 14.

[40] LSA Comments, p.2.

by the TPR Process participants themselves will now be directed to the Executive Director of the CPUC instead of the Energy Division for resolution.

Finally, with respect to the CPUC delegating its authority for inspecting records, the Utilities frequently provide information through CPUC proceedings and programs for public review. The TPR Process is consistent with these programs, and asks the Utilities to provide any confidential information only to Stakeholders who have signed a non-disclosure agreement.[41] Included in the TPR Process Description is a revised definition of "Stakeholder" clarifying who will be eligible to sign the Non-disclosure Agreement (NDA) and have access to confidential information.

General Comments

COMMENTS IN SUPPORT OF RESOLUTION E-5252

Cal Advocates supports the structure of the TPR Process and the proposed staggered timing of the release of information, stakeholder meetings, and comment periods. They believe the transparency will benefit ratepayers by creating a more holistic view of the state of transmission costs in California.[42]

The California Department of Water Resources State Water Project ("DWR") believes the TPR Process will be superior to the existing transmission review processes that are included in the TO tariffs of PG&E and SCE. DWR notes the Resolution will address issues of permanence and comprehensiveness in the existing Stakeholder Processes. The TPR Process will enable consistent stakeholder engagement in the review of all three IOUs' transmission projects more fully.[43] DWR further notes that the TPR Process will increase technical expertise as the CPUC will dedicate funds for obtaining these technical services.[44]

The Northern California Power Agency ("NCPA") asserts that IOUs have been bypassing the CAISO Transmission Planning Process ("TPP"), opting instead for self-approved projects, noting that FERC's order on a previous complaint found that PG&E

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[41] Further, because the authority sought is "cognate and germane" to utility regulation, the CPUC's authority under Public Utilities Code section 701 is liberally construed. (*PG&E Corp. v. Pub. Utilities Com.* (2004) 118 Cal.App.4th 1174, 1198; *S. California Edison Co. v. Pub. Utilities Com.* (2014) 227 Cal. App. 4th 172, 187.). Additionally, the CPUC is authorized "to '*do all things,* whether specifically designated in [the Public Utilities Act] *or in addition thereto*, which are necessary and convenient' in the exercise of its jurisdiction over public utilities." (*San Diego Gas & Elec. Co. v. Super. Ct.* (1996) 13 Cal.4th 893, 924 [internal citations omitted, emphasis original].)

[42] Cal Advocates Comments, p. 2.

[43] DWR Comments, p. 4.

[44] DWR Comments, p. 5.

did not need to do any transmission planning for asset management projects, thus the STAR Process was negotiated.[45] The TPR Process takes the STAR Process to the next level in improving oversight of IOU self-approved spending, by making these negotiated processes permanent and consistent. The TPR Process recognizes the important role that stakeholders, including wholesale customers, have in reviewing transmission data, which should be available for use in multiple fora.[46]

The Transmission Agency of Northern California ("TANC") supports the TPR Process as an essential transparency and accountability measure that will remove uncertainty of what PG&E and SCE will agree to in negotiations for any possible extension of the existing STAR Process and SRP upon their termination.[47] Further, "TANC appreciates the detailed Project Spreadsheet … as it encompasses many data routinely requested through the STAR and SRP Processes. It will greatly benefit ratepayers..."[48]

Bay Area Municipal Transmission Group ("BAMx") expresses the need for a uniform process to review the IOUs' capital transmission projects to understand transmission planning assumptions, prioritization of needs, and processes leading to transmission proposals for solving reliability upgrades and replacement of aged transmission assets.[49] BAMX also hopes that the TPR Process provides a means of advocating for cost/benefit analyses not currently included in the STAR Process and SRP.[50] BAMx also sees the larger context of transmission projects in which overlapping issues with General Rate Cases and Wildfire Mitigation Plans can be addressed.[51]

Redwood Coast Energy Authority ("RCEA") further believes the TPR Process can be used as a bridge between CAISO approved transmission projects and meeting local reliability and climate goals by allowing stakeholder feedback on what projects are needed.[52]

The Large-Scale Solar Association ("LSA") supports the enhanced transparency and review of Self-approved Projects, but recommends that projects and network upgrades approved in CAISO processes be subject to review only. LSA supports the

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[45] NCPA Comments, pp. 3-4.

[46] NCPA Comments, p. 8.

[47] TANC Comments, p. 5.

[48] TANC Comments, p. 5.

[49] BAMx Comments, p. 3.

[50] BAMx Comments, p. 4.

[51] BAMx Comments, p. 8.

[52] RCEA Comments, p. 3.

CPUC working to help TOs implement transmission projects to meet the urgent need for interconnecting clean energy resources.[53]

Solar Energy Industries Association ("SEIA") states, "[t]he proposed TPR Process will be useful in putting all relevant information before stakeholders so that they are better able to assess the progress being made to bring transmission projects online and to offer recommendations that may help facilitate the process."[54]

American Clean Power – California ("ACP") expresses support for the TPR Process, as it will devise a uniform process to review IOUs' capital transmission projects with the goals of providing clarity on projects aimed at making progress towards the state's clean energy goals.[55] ACP further notes that the TPR Process will replace and improve upon the STAR Process and Assembly Bill 970 reporting and Stakeholders will obtain specific, transparent data on the status of transmission projects.[56]

California Energy Storage Alliance ("CESA") supports the increased transparency on transmission projects and network upgrades,[57] particularly considering the lack of transparency on IOUs' processes for transmission project selection and prioritization.[58] CESA also sees the TPR Process possibly helping to determine whether energy storage and distributed energy resources can serve as alternatives to self-approved projects at lower cost.[59]

California Farm Bureau Federation ("CFBF") supports the TPR Process's transparency as it relates to transmission development's impacts on land use, food security and safety, and "skyrocketing utility costs."[60]

COMMENTS SEEKING CLARIFICATION

The CAISO and others seek clarification that the TPR Process will not reconsider the scope of projects approved as part of CAISO's TPP or network upgrades approved in CAISO's Generator Interconnection and Deliverability Allocation Procedures ("GIDAP").[61] The CAISO requests Energy Division clarify that any suggested

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[53] LSA Comments, pp. 1,3.

[54] SEIA Comments, p. 2.

[55] ACP Comments, p. 2.

[56] ACP Comments, p. 2.

[57] CESA Comments, p. 2.

[58] CESA Comments, p. 2.

[59] CESA Comments, p. 5.

[60] CFBF Comments, p. 3.

[61] CAISO Comments, p. 2.; CESA Comments, pp. 4-5; EBCE Comments, p. 2.; LSA Comments, pp. 2-3; CEERT Comments, p. 12.

alternatives in the TPR Process be limited to capital maintenance and life extension projects.[62] CEERT asserts that Stakeholder Meetings "…are not an appropriate forum to suggest new projects or projects alternatives that conflict with existing processes..."[63] While generally supportive of the TPR Process, LSA agrees it is essential not to use it as a chance to reopen already approved projects in other forums and opposes creating a new forum to scrutinize any project other than Utility Self-Approved Projects.[64] EBCE states that "[t]he Commission should not expend scarce state or party resources duplicating existing processes for review, approval, and development of transmission projects."[65]

The CPUC added language to clarify that any suggestions of project alternatives would focus primarily on self-approved projects and not on projects approved by the CAISO pursuant to a FERC tariff. In order to monitor the progress and costs of CAISO-approved projects, they are included in the TPR Process and the CPUC and stakeholders are free to ask questions about these CAISO-approved projects.

In the context of the Draft Resolution's discussion of the growth in Utilities' collective rate base, and the lack of formal review by the CAISO or the CPUC, the CAISO requests that the Resolution clarify that under its tariff, CAISO only approves "transmission expansion projects and network upgrades related to generation interconnection."[66]

The CPUC has added language to clarify that under the CAISO's current tariff, self-approved projects are not reviewed or approved by the CAISO.

Further, CAISO requests clarification of the statement that "[w]hile the TOs often reference intervenors' ability, if needed, to challenge project costs in rate cases at FERC, the lack of transparency in the project planning stage has resulted in ratepayers learning about projects after they are determined or are being implemented – too late to evaluate their development or propose alternatives." The CAISO finds this language overly broad in applying it to TPP projects.

The CPUC has added language to clarify that this statement relates primarily to self-approved projects and that there is a greater amount of earlier transparency of TPP Projects.

Finally, the CAISO points out that, while TPR Process data may be used in other fora, the CAISO has its own confidentiality requirements and non-disclosure

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[62] CAISO Comments, p. 2.

[63] CEERT Comments, p. 12.

[64] LSA Comments, p. 2.

[65] EBCE Comments, p. 1.

[66] CAISO Comments, p. 1.

agreements within its processes, and "… there are existing processes for certain sensitive CAISO-derived data."[67]

The CPUC has added language acknowledging that the CAISO has its own non-disclosure agreements and confidentiality rules that remain a requirement for accessing CAISO data.

COMMENTS EXPRESSING CONCERNS

A number of commenters express concern that the TPR Process could be a draw on time and resources away from the Utilities' implementation of needed projects.[68] EBCE asserts that the CPUC should work on "eliminating regulatory barriers and promoting efficient use of limited resources."[69]

IEP suggests that the TPR Process "threatens to become an unnecessary and burdensome exercise that could distract attention and resources from efforts to solve the current interconnection log jam and other transmission-related problems."[70]

SEIA suggests additional language in the Resolution to ensure that the Utilities' requirement to provide the expansive data in the Spreadsheet shouldn't cause a delay in the development of these projects, as it is critical to build out transmission infrastructure in the state.[71]

ACP suggests that the Commission should clarify that Resolution E-5252 will not create a new discretionary approval for transmission projects under the TPR Process and that additional staff beyond that needed to implement the STAR Process will not be needed.[72]

EBCE accurately states that "[t]he Commission has, for several years, conducted a review of transmission projects as part of negotiated-for stakeholder review processes with IOU transmission owners, through which the IOUs provide substantial information about electric transmission projects."[73] EBCE continues, "[t]hese less expansive processes have proven meritorious, without implicating the overhead issues that the Draft Resolution poses. Accordingly, EBCE proposes that the Draft Resolution be revised to simply extend and standardize these processes across the IOUs."[74]

67 CAISO Comments, p. 3.

68 CESA Comments, p. 4; EBCE Comments, p. 2.

69 EBCE Comments, p. 3.

70 IEP Comments, p. 5.

71 SEIA Comments, p. 2.

72 ACP Comments, pp. 2-3.

73 EBCE Comments, p. 2.

74 EBCE Comments, p. 2.

The CPUC modeled the TPR Process largely on the existing SCE SRP and PG&E STAR Process. These processes that EBCE appears to acknowledge as "meritorious" are only slightly less expansive than the TPR Process. The Resolution extends and standardizes these processes across the IOUs. The transparency and stakeholder engagement in the TPR Process neither approves nor rejects transmission projects and is no more burdensome than what PG&E and SCE have been doing in the last three years.

IEP identifies proceedings in which it understands the cost and need of transmission projects are already reviewed, including the CAISO's TPP, the review of specific projects' costs at FERC, and CPCN and General Rate Case proceedings at the CPUC.[75]

IEP also asserts that if the purpose of the TPR Process is to enhance the Commission's ability to participate in TO rate cases at FERC, then it should be made clear why current FERC practices prevent the Commission from receiving the information proposed in TPR Process.[76] Further, IEP suggests that for projects reviewed at FERC, the TPR Process could focus on the aspects of FERC's review that are deemed insufficient.[77]

The CPUC's impetus for the TPR Process is the lack of transparency related to nearly two-thirds of FERC jurisdictional transmission investment that receive no formal CAISO or CPUC review and approval during their planning. A small subset of the minority of projects that are approved in the CAISO's TPP receive review in a CPCN proceeding at the CPUC, and, as a matter of course, FERC does not review specific transmission projects, and Utilities are afforded a presumption they prudently incurred the capital costs and expenses included in their rate cases. Further, the TPR Process includes exclusively FERC jurisdictional transmission projects and costs. Therefore, none of the capital investments included in the TPR Process appear in the GRC. While some projects may include both FERC and CPUC jurisdictional components, only the data related to the FERC jurisdictional portion would be included in the TPR Process.

IEP expresses concern that in light of recent physical attacks, now may not be the time for a high level of transparency and suggests that using a website portal for transferring confidential information could be vulnerable to being hacked.[78]

As explained below, in response to the Utilities' concerns about the granularity of the locations of transmission assets, changes have been made to the location data to provide the Utilities the ability to redact the precise latitude and longitude data, making it subject to a TPR Process NDA. Further, Resolution E-5252 now calls for a Workshop

[75] IEP Comments, p. 2.

[76] IEP Comments, pp. 2-3.

[77] IEP Comments, p. 3.

[78] IEP Comments, p. 5.

in Summer 2023 for the Utilities to discuss numerous details about the TPR Process, including the expected format for the data and the Utilities' plans for distributing the required information.

While the Utilities express support for a uniform and permanent process, they request a six-month stay of a vote on the Resolution to work with the CPUC and Stakeholders to draft a uniform process for all three IOUs that would be filed at FERC.[79] The Utilities offer numerous reasons why they believe a FERC-based process would be preferable, including: avoiding duplicative FERC and CPUC processes,[80] FERC's discussion of the possibility of a future process in an October 2022 technical conference,[81] and avoiding individual negotiations with each utility at FERC.[82] Further, they allege a FERC-based process would: provide for consistent data for all stakeholders to review,[83] include a coordinated schedule for all three Utilities,[84] and prevent retail customers from bearing the cost to review projects that impact transmission rates.[85]

The TPR Process will not duplicate efforts at FERC, as it is intended to succeed the STAR Process and SRP beginning in 2024. As explained in Resolution E-5252, the TPR Process provides benefit to numerous other CPUC programs and proceedings, and nearly all of the costs of current FERC-based processes are already recovered from retail ratepayers. Further, two of the objectives of the TPR Process are to remove the uncertainty of negotiations and to implement a process based on nearly three years of experience by the CPUC and Stakeholders in the negotiated FERC-derived processes. The Utilities' proposed six-month delay reintroduces the uncertainty of negotiations when a majority of comments submitted confirm the need for, and benefits of, the TPR Process as proposed.

The Utilities assert that the current stakeholder processes are still in effect and cannot be changed unilaterally by CPUC resolution.[86] SCE's settlement agreement suspended the Transmission Maintenance and Compliance Review (TMCR) while the SRP is in effect. When the SRP terminates, the TMCR is automatically reinstated unless a successor process is implemented at FERC. The Utilities argue that TPR Process is

[79] Utilities Comments, p. 4.

[80] Utilities Comments, pp. 2-3.

[81] Utilities Comments, p. 6.

[82] Utilities Comments, p. 5.

[83] Utilities Comments, p. 5.

[84] Utilities Comments, p. 5.

[85] Utilities Comments, p. 9.

[86] Utilities Comments, p. 3.

duplicative of the TMCR.[87] PG&E's STAR Process requires the parties to negotiate potential changes to the tariff in good faith for potential continuation of the process in 2024, and a filing under sections 205 or 206 of the Federal Power Act is required at FERC to end the STAR Process.[88] Finally, the Utilities point out that SDG&E's Project Evaluation continues indefinitely unless a party provides notice of termination by June 30th of a given year.[89]

CEERT is further concerned that Resolution E-5252 does not consider how the TPR Process would create conflicts or delays with existing transmission planning and development processes.[90] CEERT argues the resolution seeks to subvert the FERC processes, which could lead to litigation and further delay addressing the current transmission issues.[91]

To the extent that any comparable FERC stakeholder process is duplicative of the permanent TPR Process, a Utility can request that FERC relieve them of those requirements.

According to CEERT, "…California stakeholders, especially developers of in-state renewable generation, need to be fully informed of the status and progress of utility transmission projects, many of which are and will be critical to ensuring increased delivery of clean, renewable resources…"[92]

CEERT contends that in the FERC-derived stakeholder processes, the information provided and public accessibility to data on the IOUs' transmission projects were insufficient.[93] CEERT finds it challenging to work through the data in the FERC-derived processes to find information related to generator interconnection and deliverability projects that have been included in the AB 970 Reports.[94] CEERT also comments that some stakeholders may not be involved in the processes, do not have the resources to participate in FERC transmission owner rate cases, or may not be eligible to sign NDAs to receive information in the FERC settlement processes.[95]

CEERT's desire to be fully informed of the status and progress of projects on which clean energy resources rely for interconnection and deliverability is an important factor in the development of the TPR Process. Resolution E-5252 aims to ensure

[87] Utilities Comments, pp. 2-3.

[88] Utilities Comments, p. 3.

[89] Utilities Comments, p. 4.

[90] CEERT Comments, p. 11.

[91] CEERT Comments, p. 10.

[92] CEERT Comment, p. 7.

[93] CEERT Comments, p. 6.

[94] CEERT Comments, p. 6.

[95] CEERT Comments, p. 6.

adequate access to, and usability of, sufficient data on transmission projects and network upgrades.

Procedural

A number of the comments provided input on, or sought clarification of, procedural elements of the TPR Process. While some commenters suggest the TPR Process should have more influence in the early stages of project planning or should have more power to determine the implementation of transmission projects and network upgrades, as a threshold matter, the TPR Process is an opportunity to review already-planned and already-implemented projects, with no binding authority in terms of transmission planning or rate recovery at FERC.

SEIA seeks clarity on the effective date of the resolution. While the TPR Process is to begin on January 1, 2024, Attachment C shows the first Utility making its semi-annual filing in November.[96] The Utilities also provide suggestions on the schedule of the TPR Process, including adjustments to the schedule in consideration of the winter holidays and the timing of each Utility's issuance of TPR Process data.[97] TANC suggests the CPUC consider the timing of the Utilities' TO formula rate draft annual update processes, as they may overlap the TRP Process's schedules.[98]

The CPUC has added language to the Resolution and Attachment C to clarify that the TPR Resolution will begin on January 2, 2024 for SDG&E. This is a reasonable approach, as PG&E and SCE will have issued comparable publicly accessible data in the STAR Process and SRP, respectively, on December 1, 2023. PG&E and SCE will begin their participation in the TPR Process with the release of their data in May and June 2024, respectively. Further, based on input by the Utilities and others, dates in Attachment C reflect minor adjustments and further definition.

The Utilities recommend that the CPUC provide an opportunity for Energy Division and the Utilities to have a series of meet and confer sessions regarding the specific language and terms of the TPR Process before it is adopted to ensure that it is workable for all stakeholders and does not impose an undue burden on the Utilities or unnecessary costs on California ratepayers.[99]

Cal Advocates also suggest Energy Division host a workshop to refine the Draft Resolution prior to approval. They suggest a workshop would allow for several clarifications, including how the TPR Process impacts the STAR Process and SRP. They

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[96] SEIA Comments, p. 2.

[97] Utilities Comments, p. 14.

[98] TANC Comments, p. 5.

[99] Utilities Comments, pp. 14-15.

also assert this will also be an opportunity to hear from other stakeholders on what the utilities should include on transmission projects in the Spreadsheet.[100]

The Commission believes that the extended comment period on the Draft Resolution provided sufficient time for Stakeholders to comment on the process and substance of the TPR Process, which many Stakeholders did. The Commission does not believe it to be necessary to postpone approval of the TPR Process. However, Energy Division will hold a workshop with the Utilities and Stakeholders in the Summer of 2023 to clarify details on how the TPR Process will be implemented beginning in 2024. Language has been added to the Resolution to indicate this.

The workshop agenda will include, but not be limited to: general expectations of the TPR Process; the format of the data to be provided to the CPUC and Stakeholders, including information in the Project Spreadsheet, Approval Documents, and Procedures; the means through which the Utilities will make both public and confidential data available to the CPUC and Stakeholders; the schedule of the TPR Process; and any additional information the Utilities feel is necessary to provide and any questions Stakeholder may have related to the substance and process of the TPR Process.

Cal Advocates also requests clarification that Commission Staff, which include the Public Advocates' Office, do not need to sign NDAs.[101] Unlike the FERC-derived stakeholder processes, the TPR Process is a CPUC-administered process. Therefore, language has been added to the Resolution making it clear that no NDAs will be needed for any CPUC Staff to access confidential TPR Process materials.

Finally, in terms of the implementation of the TPR Process, BAMx suggests that the identified $1.5 million in annual consulting services for the TPR Process may not be sufficient, and instead, Resolution E-5252 should articulate the scope of services, the cost of which would be determined at a later time.[102]

The scope of work and budget for the TPR Process are currently in the budgeting and contracting process, which will include Requests for Proposals. Adjustments to this budgeted amount may be considered in the future.

Comments on Substantive Elements of the TPR Process

A number of comments addressed substantive requirements of the TPR Process. In addition to the substantive elements addressed below, other substantive comments

[100] Cal Advocates Comments, pp. 2-3.

[101] Cal Advocates Comments, p. 4. stating that Cal Advocates has such authority under PU Code Sections 309.5 and 314, and PU Code Section 583.

[102] BAMx Comments, p. 4.

were outside of the intended and/or permitted scope of the TPR Process, while others captured elements that are better included in follow-up data requests than in designated data fields.

RCEA recommends considering additional data accuracy metrics to verify actual and perceived delays at the transmission level, such as assessing interconnection feasibility, interconnection cost, and transmission planning.[103] Additionally, RCEA suggests a focus not only on costs, but on prioritization of transmission projects for serving electric load, as well as reliability and meeting the needs of underserved customers.[104] RCEA also underscores the importance of sharing data across various CPUC proceedings.[105]

ACP recommends structuring the reporting requirements to identify potential delays, their causes, and their impacts in coordination with the reporting that will be required in the RPS proceeding starting this year.[106] ACP states the utilities should also be required to explain their prioritization rankings and report their staffing in the interconnection/transmission planning groups, documenting any staff or resource shortages that contributed to reprioritizations.[107]

The Commission believes that the semi-annual Project Spreadsheets, Authorization Documents, and Procedures, in combination with information requests and Stakeholder meetings will make the information desired by both RCEA and ACP available to Stakeholders.

SEIA proposes the addition of language to the TPR Process Description: "This TPR Process, including document submission, stakeholder engagement of all types, and potential dispute resolution will not inhibit the IOU from advancing with the development, construction, and operation of any of the electric transmission projects included in the TPR Process Project Spreadsheets."[108]

The Commission understands the concern that transmission projects and network upgrades, particularly those needed for generator interconnection that have been approved in a CAISO process, should not be burdened by "re-litigation" in the TPR Process. Language has been added to Resolution E-5252 to clarify that such projects, while subject to review and inquiry by Stakeholders in the TPR Process, are included primarily for the purpose of monitoring the progress and costs of these projects. As nearly two-thirds of the Utilities' transmission investment does not receive

[103] RCEA Comments, p. 5.

[104] RCEA Comments, p. 2.

[105] RCEA Comments, p. 2.

[106] ACP Comments, p. 1.

[107] ACP Comments, p. 4.

[108] SEIA Comments. P. 2.

CAISO review and approval, applying SEIA's proposed language to "any of the electric transmission projects in the TPR Process…" would likely undermine the ability to review, understand, and at times scrutinize the self-approved majority of projects in the TPR Process.

CFBF suggests that the TPR Process should incorporate the requirements of Senate Bill 529 (Hertzberg – 2022),[109] which, according to CFBF, requires the CPUC "to update its rules to allow each investor-owned electric utility (IOU) to use an accelerated process for approval to construct an extension, expansion, upgrade or other modification to its existing electric transmission facilities."[110]

While the TPR Process will likely include transmission projects addressed by Hertzberg – 2022, and will provide useful data for the CPUC's permitting processes under a revised General Order (GO) 131-D (i.e., GO 131-E), the TPR Process itself does not require the Commission's binding permitting authority.

Cal Advocates provided a number of suggestions, including: the ability to sort for types of projects; a project's location with respect to substations; the percentage of contingency included in a project's cost forecast, as well as the actual cost contingency spent to date; to-date construction work in progress costs (CWIP); abandoned plant cost recovery applied for; and avoiding sub-columns and sub-rows, which can make data management challenging.[111]

Cal Advocates also encourages the Commission to ensure that the public version does not unnecessarily redact information beyond the level that currently occurs in PG&E's STAR Process.[112]

Regarding Cal Advocates' substantive recommendations, the CPUC has added language to Resolution E-5252 to ensure that all columns are sortable. Data fields 38 and 39 require identification of projects included in the TPP and GIDAP, respectively. GIDAP Projects are typically those included in the current AB 970 Reports. Regarding

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[109] Hertzberg – 2022 added Section 564 to the Public Utilities Code states, "By January 1, 2024, the commission shall update General Order 131-D to authorize each public utility electrical corporation to use the permit-to-construct process … to seek approval to construct an extension, expansion, upgrade, or other modification to its existing electrical transmission facilities … within existing transmission easements, rights of way, or franchise agreements, irrespective of whether the electrical transmission facility is above a 200-kilovolt voltage level." It also amended Section 1001 of the Public Utilities Code to include the following in subdivision (b): "The extension, expansion, upgrade, or other modification of an existing electrical transmission facility, including transmission lines and substations, does not require a certificate that the present or future public convenience and necessity requires or will require its construction."

[110] CFBF Comments, p. 4.

[111] Cal Advocates Comments, pp. 7-8.

[112] Cal Advocates Comments, p. 2, 6.

project cost contingencies, data field 48, "AACE Class," will provide information on the accuracy of the current cost estimate, and information requests on specific projects and cost estimation procedures can provide further information.

To better understand CWIP to date, language has been added to the Project Spreadsheet template to require both actuals and forecast costs for the current year. Regarding abandoned plant, any 100% abandoned plant treatment incentive granted by FERC would be indicated in data field 67. Understanding that sub-columns make data management challenging, any alternatives and costs will be included in one column.

Finally, it is reasonable that Stakeholders and the CPUC receive clear justification for any redacted data. The Utilities' determination of what data is considered confidential and would therefore be redacted in publicly issued data will be part of a discussion at a Workshop in Summer of 2023.

TANC also recommends that the CPUC should ensure that stakeholders will be able to propose modifications to data to be provided within the Project Spreadsheet and that the TPR Process data may be used by stakeholders in multiple fora.[113]

The CPUC has added language to the Resolution to afford Stakeholders the opportunity to raise and discuss at the first Stakeholder meeting in a calendar year any proposed adjustments to the TPR Process data. Regarding use of TPR data, there is language in the Resolution that data provided in the TPR Process can be used in other fora, subject to confidentiality restrictions.

Utilities' Suggestions for Substantive Changes

Definitions

The Utilities provide numerous proposed revisions and edits to Attachment A (i.e., the TPR Process Description), as described and responded to below.

They argue definition of "Critical Energy Infrastructure Information or CEII" should be consistent with the definition currently used in SCE's SRP as "[i]nformation as defined in 18 CFR § 388.113(c)(1), or successor regulation."[114]

The CPUC has added language to include the required definition and procedure required at FERC for CEII designation.

They suggest deleting from the definition of "Federal Energy Regulatory Commission or FERC" that the review of costs and expenses for prudency is "rarely used."[115]

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[113] TANC Comments, p. 6.

[114] Utilities Comments, p. 11.

[115] Utilities Comments, p. 11.

The CPUC has deleted this section of the definition.

The Utilities suggest that the definition of "Non-CAISO Project," should not include the clause "reviewed or" and instead should include "[a]n electric transmission Project that is not approved in the CAISO Transmission Planning Process." The Utilities claim that while CAISO does not approve asset replacement projects, it may review them to evaluate "right-sizing" opportunities.[116]

While the Commission is unaware of asset replacement projects receiving transparent review in the CAISO's transmission planning process, the CPUC has adjusted the definition to provide for that possible occurrence.

They suggest the definition of "Procedures" should align with what Utilities' procedures include and their purpose.[117]

The breadth of procedural documents is important for transparency. The CPUC added "standard" to enhance the definition.

The Utilities suggest the definition of "Project" should be clarified to include only projects with actual or forecasted capital costs of $1 million or more (as opposed to expense costs).[118]

They suggest the definition of "Project Spreadsheet" should also reflect this change and should not include requirements for the past five and future five years, as the relevant timeframe is already set forth in Section 2.1.2. The Utilities also propose to add a reference to the Project Spreadsheet attachment to the Resolution.[119]

The CPUC has added language to clarify the definitions for both "Project" and "Project Spreadsheet."

The Utilities, CEERT, and IEP commented on the definition of "Stakeholder." The Utilities comment that the definition need not reference confidential information, as the treatment of that information is addressed in Sections 2.1.7 and 2.1.8 of the TPR Process Description.[120] CEERT feels that based on the definition in the Draft Resolution, it was unclear who would have access to confidential information.[121] IEP similarly weighed in expressing concern about the breadth of the definition of Stakeholder in the Draft Resolution.[122]

While the TPR Process is not transmission planning, the CPUC has changed the definition of "Stakeholder" in Resolution E-5252 to be more consistent with the

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[116] Utilities Comments, p. 11.

[117] Utilities Comments, p. 11.

[118] Utilities Comments, p. 11.

[119] Utilities Comments, pp. 11-12.

[120] Utilities Comments, p. 12.

[121] CEERT Comments, p. 9.

[122] IEP Comments, p. 4.

definition used, and those entities eligible to receive confidential data, in the CAISO's Transmission Planning Process.

The Utilities recommend that the definition of "Transmission Project Review Process or TPR Process" be changed to delete language regarding an "expectation that the outcomes of the TPR Process inform the implementation of a Utility's transmission Projects and the capital costs that are ultimately included in a Utility's transmission rates at FERC."[123]

The CPUC has removed the reference to costs in rates at FERC from the definition.

The Utilities argue that the term "Utility Self-Approved Project" should be removed since it is duplicative of "Non-CAISO Project." The Utilities claim that all projects must be approved by FERC for recovery, and FERC refers to non-transmission expanding projects as "asset management projects."[124]

The Commission believes it is reasonable to use "Utility Self-Approved," "Non-CAISO," and "asset management" interchangeably. The definition in the Draft Resolution will remain because, as a matter of course and pursuant to FERC's presumption of prudence, specific projects are not reviewed and approved by FERC for rate recovery.

<u>Data</u>

The Utilities suggest that the Project Spreadsheet described in Section 2.1 of the TPR Process Description should include projects that had capital expenditures in the last four years, have actual or forecast capital expenditures in the current year, and forecast capital expenditures in the four future years. While PG&E provides five future years of data in the STAR Process, the Utilities claim that both SCE and SDG&E are unable to provide for five future years.[125]

The CPUC has changed the description to include forecast capital expenditures of the current year and four future years, and actual data to include the prior five years of data.

Regarding Section 2.1.4 of the TPR Process Description, the Utilities acknowledge that given the volume of data requested in the Project Spreadsheet, errors in the data are possible. Recognizing the obligation to provide accurate information to the Commission, the Utilities assert that revising the Project Spreadsheet as errors are identified could create a significant burden and version control issues for Stakeholders.

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[123] Utilities Comments, p. 12.

[124] Utilities Comments, p. 12.

[125] Utilities Comments, p. 12.

The Utilities suggest that should errors be identified in the Project Spreadsheet, a Utility would provide notice of the error and the corrected data within 10 business days of discovering the error, if available. The Utilities will then correct the error in the next semi-annual Project Spreadsheet.[126]

The CPUC has added language to indicate that if errors are identified, the utilities shall provide notice of the error as soon after discovering the error as practicable and will provide the corrected data, on a best-efforts basis, to stakeholders within 10 business days. Depending on the extent of the errors, the Utility may be expected to issue a new Project Spreadsheet within 10 days of the discovery of the error with the corrected data fields identified.

Regarding Section 2.1.8 of the TPR Process Description, Critical Energy Infrastructure Information ("CEII") being provided to Stakeholders that execute a NDA, the Utilities note that some CEII may be provided only to specific appropriate regulators. The TPR Process should provide the Utilities with sufficient discretion to limit the disclosure of CEII.[127]

Resolution E-5252's revised definition of Stakeholder, the clearer definition of CEII, and the required review and approval by the CPUC of each Utility's NDA are all complementary to this request. Further, it is anticipated that details related to the disclosure of, and limitations on, CEII within the TPR Process will be discussed and clarified in a workshop facilitated by Energy Division in the third quarter of 2023.

The Utilities comment that Section 2.2 of the TPR Process Description should be revised to allow confidential information or CEII to be redacted from Authorization Documents provided to Stakeholders that have not executed a NDA.[128]
Changes have been made to the language in this section.

The Utilities recommend a new provision be added to Sections 2.5 and 3.1.3 to specify that they are not required to create or develop additional processes, documentation, or materials for the TPR Process other than the materials and information that the Utilities already possess.[129]

While the Commission does not anticipate that the creation of new materials will be needed to satisfy the information requirements of the TPR Process, if the data currently kept by a Utility is insufficient for populating the Project Spreadsheet, or if Authorization Documents or Procedures are out-of-date or provide inadequate information on a Utility's transmission project development and implementation, then

[126] Utilities Comments, p. 12.

[127] Utilities Comments, p. 12-13.

[128] Utilities Comments, p. 13.

[129] Utilities Comments, p. 13.

there could be instances in which additional information would needed to meet the requirements of the TPR Process.

Information Requests and Stakeholder Meetings

The Utilities suggest revisions to Sections 3.1, 3.2, and 4.3 in the TPR Process, which state that a Utility "shall" respond or provide information within a certain time period. The Utilities claim that meeting such deadlines may not always be possible.[130]

The CPUC has added "best efforts" language to sections 3.1 and 3.2 with a requirement to provide the CPUC and all Stakeholders with a timely explanation of why a response cannot be provided within the expected time frame. This same "best efforts" standard does not apply to section 4.3, as the Commission believes that a Utility should be prepared to discuss its own projects and processes in a Stakeholder meeting with the sufficient notice provided in section 4.3.

The Utilities are concerned about an apparently open-ended discovery period in Section 3.2. They suggest that the language be revised to clarify that discovery outside of the established windows is limited to follow-up clarification inquiries on information provided in prior requests. They reason that Stakeholders can follow up with additional data requests in the next data cycle.[131]

The CPUC has clarified the language to indicate that the subsequent project-specific data requests shall relate to prior information requests and/or responses but do not need to be about the same specific projects.

Specific Data Fields

The Utilities provided numerous suggestions on the data fields in Attachment B to Resolution E-5252, which is the template for the TPR Process Project Spreadsheet.

For Line #1, "Row/Line No.," the Utilities suggested applying the $1 million threshold for inclusion at the subproject level instead of including all components if the total project meets or exceeds $1 million. It was further suggested that projects only be included for four historical years and four forecast years beyond the current year.[132]

The only change the CPUC has made to this data field is to limit the forecast years to the current year plus four forecast years. However, in the November through February data cycle, the "current year" will be considered the year beginning in this time period, plus four years after that. Therefore, the five historical years for the

[130] Utilities Comments, p. 13.

[131] Utilities Comments, p. 13.

[132] Utilities Comments, Appendix A, p. A-9.

November through February data cycle will include the year ending during this November through February time period and the four years before that.

For Line #2 "Project Name," the Utilities recommended removing the requirement to provide any other name that has been used to identify a project, as they do not track changes in project names. Further, they note that the name used in the CAISO TPP is included in the ID#2 data field.[133]

The CPUC is keeping this data field as written in the Draft Resolution. As the goal of the TPR Process is to provide the transparent review of projects, it is a reasonable request to know whether a Project's name has changed.

Line #3, "Location 1," the Utilities pushed back on the inclusion of latitude and longitude coordinates as being cumbersome with no real benefit and that it could potentially raise physical security concerns.[134] Regarding Line #4, "Location 2, City/Cities and County/Counties," the Utilities recommend that because some programs can includes several cities, it would make sense to just include the county if more than one municipality is included.[135]

The Commission does not believe the inclusion of latitude and longitude to be cumbersome or unimportant. However, in consideration of the concern related to highly granular latitude and longitude data, Location 1 may be redacted by the Utilities, and made subject to a TPR Process NDA, while Location 2 will continue to require the inclusion of every city and county included in a project's scope.

In Line #8, "Related Projects," the Utilities requested clearer language to ensure that this data field includes projects with operational dependencies or are bundled for efficiencies, and not simply because they are constructed concurrently. The Utilities also aimed to clarify that this information is only required for other projects in the Project Spreadsheet.[136]

The CPUC has clarified the language in the description of this data field in Attachment B.

For Line #14, "Types of Analyses," the Utilities propose including a drop-down menu of analyses performed with an "other" option that could be clarified through information requests. They further suggest eliminating the identification of analyses that indicated the need for the project.[137]

The Commission believes that specific analyses performed are reasonable to include in the data provided. "Other" analyses should be specifically named in the

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133 Utilities Comments, Appendix A, p. A-9.

134 Utilities Comments, Appendix A, p. A-9.

135 Utilities Comments, Appendix A, p. A-10.

136 Utilities Comments, Appendix A, p. A-10.

137 Utilities Comments, Appendix A, p. A-10.

Project Spreadsheet. Also, it is important to understand what analyses showed the work was needed.

Utilities argue that for Line #15, "Alternative Solutions and Cost," "if applicable" should be added.[138]

The Commission believes it is reasonable to consider possible alternatives for all transmission investments. If a Utility chooses to populate this data field with "N/A," this determination that consideration of alternatives is not applicable is useful information for the CPUC and Stakeholders and could be pursued in information requests.

For Line #18, indicating whether a project is a measure in a Utility's Risk Assessment and Mitigation Phase ("RAMP"), the Utilities note that "[s]pecific FERC-jurisdictional projects have not routinely been initiated to specifically mitigate a RAMP risk."[139]

The Commission believes that transmission projects could be included in the RAMP, and it is helpful to the CPUC and Stakeholders to understand this information.

The Utilities feel that Line #20, "Project Manager," should be replaced with the name of a regulatory contact, arguing that there are issues about confidentiality and questioning the usefulness of this information.[140]

While information requests in the TPR Process will likely be sent to an identified individual or team at each Utility, in both SCE's and PG&E's FERC-derived stakeholder processes, the information about who is in charge of specific and programmatic projects has been helpful for understanding the interrelatedness of projects and data.

For Line #47, "Project Status," the Utilities indicate that they do not track the percentage of construction completed on projects.[141]

The CPUC has changed the data required in this data field to percentage ranges, (i.e., less than 10%, 10%-25%, 25% - 50%, 50% -75%, 75%- 100%). It is a reasonable expectation for a Utility to indicate this level of progress on projects.

The Utilities recommend for Line #51, "Current Projected or Actual In-Service Date," language should be changed to indicate "[a]t the time the data was extracted for the Utility's Database(s) as provided in Section 2.1.5 of the TPR Process."[142]

The Commission sees this as a reasonable request, so long as all data have been extracted from a Utility's database no more than 60 days from the date that the Project Spreadsheet is issued.

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[138] Utilities Comments, Appendix A, p. A-10.

[139] Utilities Comments, Appendix A, p. A-10-A-11.

[140] Utilities Comments, Appendix A, p. A-11.

[141] Utilities Comments, Appendix A, p. A-11.

[142] Utilities Comments, Appendix A, p. A-11.

Regarding Line #54, "Original Projected Cost or Cost Range," the Utilities propose deleting, "If this single project line in the spreadsheet represents the sum of the project, that is the number that should be here. If this project line is a subpart of a larger project, the original cost for that subpart should be here." Using PG&E terminology, the Utilities explain that original projected project cost is only determined at the T.Dot Level (i.e., the totality of the project) and not at the PO level (i.e., planning order or project sub-part) if there are multiple POs under a T.Dot.[143]

The CPUC has made this change. However, all subparts of projects must be included in the Project Spreadsheet for all projects that in their totality have actual or forecast capital costs of $1 million or more. In other words, while the original estimated cost may be expressed in terms of the totality of the project, the CPUC and Stakeholders must have visibility of all project sub-parts such that they can be summed to determine current total expected project costs.

For Line #55, "Cost Cap," the Utilities suggest adding language referencing CPCNs and assert that the only binding cost caps would be those relating to a FERC Order 1000 competitive bid in the CAISO's TPP.[144]

In addition to referencing CPUC proceedings that may determine a maximum reasonable and prudent cost, the CPUC has added language to this data field's description referencing competitively bid projects in the CAISO's TPP.

For Line #56, "Current Projected Total or Actual Final Cost," and Line #57, "Actual Capital Expenditures," the Utilities recommend reducing the historical data to four years, consistent with SCE's SRP.[145]

The CPUC finds it reasonable and helpful to have five years of historical data.

The Utilities further comment that in the Project Spreadsheet, for Programmatic Projects that do not yet have over $1 million of recorded capital expenditures, but are expected to, the information reported will be limited. The Utilities also believe it reasonable for "not applicable" (N/A) to be a reasonable response for some data fields.[146]

The CPUC expects complete data to be provided for all Projects, including programmatic work that is expected to incur costs of $1 million or more at some point. As programmatic work is often within less transparent programmatic "buckets," this data should be as thorough as possible.

[143] Utilities Comments, Appendix A, p. A-11.

[144] Utilities Comments, Appendix A, p. A-12.

[145] Utilities Comments, Appendix A, p. A-12.

[146] Utilities Comments, Appendix A, p. A-12-A-13.

TPR Process Schedule

Regarding the TPR Process Schedule, the Utilities suggest numerous specific changes to the schedule.[147] Included in these proposed changes are suggestions to align the TPR Process with the Utilities' formula rate case schedules and accommodate the winter holidays. Further, the Utilities assert that the 10-year retention requirement in the schedule is burdensome and would be difficult to implement.[148]

The CPUC has provided more defined dates in Resolution E-5252 that provide added time for responding over the winter holidays and that remain consistent with timing in the TPR Process Description. Also, the retention requirements have been reduced from ten to five years.

In their proposed changes to the schedule, the Utilities recommend striking the reference in Attachment C that the data "should correspond with the Utility's Formula Rate or Annual Update filing at FERC for the following rate year in its TO rate case."[149] TANC also requested clarification of what is meant by this language, expressing support for Projects included in the TPR Process corresponding with those Projects included in rate case filings at FERC.[150]

While the intent of this language was to ensure that Projects and data in the TPR Process are consistent with that presented in the forecast capital additions in the Utilities' TO rate case filings at FERC, the CPUC has removed this specific language from this section of the schedule. This expectation remains, but timing in data extraction for the TPR Process may result in some differences when compared to the TO rate case filings. The CPUC has added the requirement that the TPR data must be extracted no more than 60 days prior to a Utility issuing its Project Spreadsheet. Also in this section of the TPR Process Schedule, the CPUC has added language that is consistent with the TPR Process Description's requirement that the semi-annual data include the Project Spreadsheet, Authorization Documents, and Procedures.

Also consistent with the TPR Process Description, the TPR Process Schedule now includes dates by which Stakeholders and the CPUC may provide agenda items to the Utilities for the Stakeholder meetings.

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[147] Utilities Comments, Appendix A, p. A-14-A-19.

[148] Utilities Comments, p. 14.

[149] Utilities Comments, Appendix A, p. A-14-A-19.

[150] TANC Comments, p. 5.

Conclusion

A majority of comments support the establishment of the TPR Process, others sought clarification of details, and a few opposed the establishment of the TPR Process. The Commission has addressed questions or concerns raised in comments in Resolution E-5252. These include refinements and clarification of the TPR Process Description, the Project Spreadsheet's data fields, and the TPR Process Schedule. Further, Utilities are being directed to work with Energy Division to convene a workshop within 120 days of the passage of Resolution E-5252 to provide details on and answer Stakeholders' questions related to the implementation of the TPR Process.

FINDINGS AND CONCLUSIONS

1. The majority of electric transmission capital projects are not reviewed and approved by the CAISO or the CPUC. These Utility Self-Approved Projects currently comprise 63% of the three IOUs' transmission capital additions to rate base.
2. Transmission Project costs, Utilities' collective transmission rate base, and transmission rates have increased many times in the last decade.
3. Current stakeholder processes negotiated in PG&E's and SCE's last rate cases, and the more limited Project Evaluation in SDG&E's rate case settlement, are temporary and inconsistent.
4. The Transmission Project Review Process will provide greater ongoing and consistent transparency of transmission Projects with a robust Project Spreadsheet, Procedures, and Authorization Documents; opportunities for inquiry and comments by the CPUC and Stakeholders; and Stakeholder meetings.
5. Benefits from the Transmission Project Review Process include more efficient and cost-effective transmission Projects, particularly related to Utility Self-Approved Projects.
6. While the primary focus of the Transmission Project Review Process is on Utility Self-Approved Projects, CAISO-approved transmission Projects and network upgrades are also included to enable the monitoring of projects' progress and costs.
7. Further benefits to CPUC programs and proceedings include, but are not limited to, those related to permitting and CEQA review, Integrated Resource Planning, the Distributed Energy Resources Action Plan, General Rate Cases, wildfire mitigation and recovery, and risk and safety assessments.
8. Qualifying Stakeholders will be eligible to access confidential data subject to non-disclosure agreements (NDA) and applicable confidentiality rules. CPUC staff, including the Public Advocates Office, will not be required to sign NDAs.

9. The Transmission Project Review Process will begin on January 1, 2024.

THEREFORE IT IS ORDERED THAT:

1. Under the Direction of Energy Division, the Transmission Project Review (TPR) Process shall begin on January 1, 2024, as described in this Resolution and related Attachments.
2. The first data in the TPR Process will be provided by San Diego Gas & Electric Company on January 2, 2024. Pacific Gas and Electric Company will provide its first data on May 1, 2024, and Southern California Edison will provide its first data on June 3, 2024.
3. Not more than 75 days after Commission approval of Resolution E-5252, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file via Tier 2 Advice Letter, for review and approval by Energy Division, a draft Non-disclosure Agreement to be used in the Transmission Project Review Process. The final NDAs will be signed by eligible Stakeholders in the TPR Process before having access to confidential information.
4. Not more than 120 days after Commission approval of Resolution E-5252, Energy Division, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall hold a workshop to address issues including, but not limited to expectations of the TPR Process; the format of the data to be provided to the CPUC and Stakeholders in the Project Spreadsheet, Approval Documents, Procedures, etc.; the means through which the Utilities will make both their public and confidential data available; the schedule of the TPR Process; and any additional information the Utilities feel is necessary to provide and any questions the CPUC and Stakeholders may have related to the substance and process of the TPR Process.

This Resolution is effective today.

I certify that the foregoing Resolution was duly introduced, passed, and adopted at a conference of the Public Utilities Commission of the State of California held on April 27, 2023; the following Commissioners voting favorably thereon:

/s/ RACHEL PETERSON
Rachel Peterson
Executive Director

ALICE REYNOLDS
President
GENEVIEVE SHIROMA
DARCIE HOUCK
JOHN REYNOLDS
KAREN DOUGLAS
Commissioners

ATTACHMENT A

TRANSMISSION PROJECT REVIEW PROCESS DESCRIPTION

Below are the proposed provisions for the Transmission Project Review Process

1. Definitions

1.1. Authorization Documents: Internal Utility documents used at any stage of a Project for management authorization or re-authorization of the Project.

1.2. California Independent System Operator or CAISO: CAISO "manages the flow of electricity across the high-voltage, long-distance power lines for the grid serving 80 percent of California and a small part of Nevada. The nonprofit public benefit corporation keeps power moving to homes and communities."[151] Among CAISO's duties are administration of the Transmission Planning Process and the Generator Interconnection and Deliverability Allocation Procedures.

1.3. CAISO Project or CAISO-approved Project: An electric transmission Project that is reviewed and approved in the CAISO Transmission Planning Process.

1.4. Critical Energy Infrastructure Information or CEII: Information that can be shown by the Transmission Owner to have been designated as CEII by FERC following procedures in 18 CFR § 388.113 (d) and (e), and as defined in 18 CFR § 388.113(c)(1), or successor regulation.

1.5. Federal Energy Regulatory Commission or FERC: Independent federal agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC has the authority to approve just and reasonable transmission rates.

1.6. Generator Interconnection and Deliverability Allocation Procedures or GIDAP or Generator Interconnection Process: The CAISO's GIDAP implements the requirements for both small and large generating facility interconnections to the CAISO-controlled transmission grid and provides a process for allocating transmission plan deliverability for interconnection requests.

[151] http://www.caiso.com/about/Pages/OurBusiness/Default.aspx

1.7. Investor Owned Utility (IOU): Unless otherwise stated, see "Transmission Owner."

1.8. Non-CAISO Project: An electric transmission Project that is not reviewed and approved in the CAISO Transmission Planning Process.

1.9. Procedures: Procedures, standards, strategies, processes, or any documents created by the Utility to identify, propose, authorize, plan, prioritize, budget, and implement a Project included in the TPR Process Project Spreadsheet.

1.10. Project: Any FERC-jurisdictional electric transmission project with actual or forecasted costs of one million dollars or more, which a Utility has included or intends to include in its FERC-jurisdictional electric transmission rate base, including both CAISO Projects and Non-CAISO Projects. These costs include those for materials, labor, overhead, and allowance for funds used during construction. A Project would include all of the components of a specifically identified Project, as well as programmatic or "blanket" work categories.

1.11. Project Spreadsheet: Provided to the CPUC and Stakeholders semi-annually, the Project Spreadsheet shall be sortable and contain up-to-date data on all Projects with actual or forecast costs of one million dollars or more, regardless of whether they were included in the CAISO's Transmission Planning Process. The Project Spreadsheet is included as Attachment B to Resolution E-5252.

1.12. Stakeholder[152]: A CAISO Market Participant;[153] an electric utility regulatory agency other than the CPUC within California; an Interconnection Customer that has submitted an Interconnection Request to the ISO under the

[152] The "Receiving Entities" identified in the CAISO's "Non-Disclosure and Use of Information Agreement for Transmission Planning Data" track the entities who are intended to be Stakeholders in the TPR Process. See https://www.caiso.com/Documents/RegionalTransmissionNon_DisclosureAgreement.pdf.

[153] As described in Appendix A to the CAISO's Fifth Replacement Tariff (September 1, 2022), a Market Participant in An entity, including a Scheduling Coordinator, who (1) participates in the CAISO Markets through the buying, selling, transmission, or distribution of Energy, capacity, or Ancillary Services into, out of, or through the CAISO Controlled Grid; (2) is a CRR Holder or Candidate CRR Holder; (3) is a Convergence Bidding Entity; or (4), for purposes of scheduling and operating the Real-Time Market only, is an EIM Market Participant.

ISO's Large Generator Interconnection Procedures or Small Generator Interconnection Procedures (LGIP or SGIP); a developer having a pending or potential proposal for development of a Generating Facility or transmission addition, upgrade or facility and who is performing studies in contemplation of filing an Interconnection Request or submitting an infrastructure project through the ISO's Transmission Planning Process; a not-for-profit organization representing consumer regulatory or environmental interests before Local Regulatory Authorities or federal regulatory agencies; or an entity providing consulting services or support to a party eligible to receive Confidential Information according to the criteria described above.

1.13. Transmission Owner (TO): An entity owning FERC-jurisdictional transmission facilities whose operational control has been transferred to the CAISO. For the TPR Process, relevant TOs include: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

1.14. Transmission Planning Process or TPP: CAISO's TPP engages stakeholders and public input and uses engineering analysis to determine capacity-expanding transmission projects that address short- and long-term reliability, economic, and public policy needs.

1.15. Transmission Project Review Process or TPR Process: The process described in this document. The TPR Process includes semi-annual data reporting, Stakeholder meetings, opportunities to request data and information from each utility, the opportunity to comment on each utility's transmission Projects, Procedures, and Authorization Documents, with the expectation that the outcomes of the TPR Process inform the implementation of a Utility's transmission Projects.

1.16. Utility: Unless otherwise stated, see "Transmission Owner."

1.17. Utility Self-Approved Project: Unless otherwise stated, see "Non-CAISO Project."

2. Information on Transmission Projects

2.1. Pursuant to the TPR Process, a Utility must furnish a sortable Project Spreadsheet containing the Project-specific data identified in Attachment B to

Resolution E-5252 for all electric transmission Projects as defined in Section 1.10 above. For any project meeting those criteria, the Project Spreadsheet must be fully populated for each Project with data extracted from the Utility's database no more than 60 days prior to the data being provided. If the Utility is providing data that is less than complete, written notification, an explanation of the deficiencies, and when the deficiencies will be remedied shall be provided to the CPUC and Stakeholders no fewer than five business days prior to date the Project Spreadsheet is to be issued.

2.1.1. The Project Spreadsheet shall include all Projects, including those that have been, or will be, included in the CAISO Transmission Planning Process, FERC jurisdictional transmission network upgrades required for generator interconnection, as well as Utility Self-Approved Projects.

2.1.2. The Project Spreadsheet shall contain current Project-specific actual and forecast data for all electric transmission Projects that had any capital expenditures in the prior five calendar years. For the November through January issuances of the Project Spreadsheet, the five prior years shall be considered the calendar year that ends during this November through January time period plus the four years prior to the calendar year that ends during this November through January time period. In the May through July Project Spreadsheet issuances, the same prior years will be used as in the previous November through January time period. All capital expenditures not yet recorded but forecast for the calendar year ending during the November through January time period should be included and identified.

2.1.3. The Project Spreadsheet shall contain current Project-specific actual and forecast data for all projects with any capital expenditures in the current year or the next four years. For the November through January issuances of the Project Spreadsheet, the "current year" shall be considered the calendar year that begins during this November through January time period plus the four years that follow the calendar year that begins during this November through January time period. In the May through July Project Spreadsheet issuances, the same forecast years will be included as in the previous November through January time period.

2.1.4. The data in the Project Spreadsheet shall be as complete, accurate, and verifiable as possible. If the Utility identifies or is made aware of data errors in the Project Spreadsheet, the Utility will provide notice of the errors as soon as practicable after discovering the errors. The Utility will provide the corrected data, on a best-efforts basis, to the CPUC and Stakeholders within 10 business days of discovering the errors. If unable to provide corrections within 10 days, the Utility will provide a written explanation why it is unable to meet this expectation. Depending on the extent of the errors, the Utility may be expected to issue a new Project Spreadsheet within 10 days of discovering the errors with the corrected data fields identified. The errors will also be corrected in the next semi-annual update of the Project Spreadsheet.

2.1.5. The Project Spreadsheet shall identify the date that the data were extracted from the Utility's database(s).

2.1.6. The Utility shall update and provide the Project Spreadsheet to Stakeholders on a semi-annual basis, highlighting all new Projects added to the Project Spreadsheet, and any changes to the previously distributed Project Spreadsheet.

2.1.7. There shall be a public version and, as applicable, a confidential version of each semi-annual Project Spreadsheet. The public version shall be distributed to a maintained distribution list and made available on each Utility's website with any confidential data and Critical Energy Infrastructure Information ("CEII") redacted.

2.1.8. Information that is confidential or designated as CEII and included in the Project Spreadsheet shall be provided to certain Stakeholders pursuant to CPUC and FERC limitations. Access to the confidential and/or CEII information will require a signed non-disclosure agreement. Depending on the nature of the CEII information, disclosure may be limited to the CPUC. Each Utility will submit its proposed non-disclosure agreement to Energy Division for approval via a Tier 2 advice letter no more than 75 days after Commission approval of Resolution E-5252.

2.2. The Utility shall provide Authorization Documents, as defined in Section 1.1 above, for Projects included in the Project Spreadsheet. These documents will be updated on a semi-annual basis to provide any new Authorization Documents, or modifications to previously provided Authorization Documents. For Stakeholders that have not executed a signed non-disclosure agreement, Authorization Documents shall be redacted to remove CEII, customer and/or proprietary or confidential information.

2.3. The most current version of the Utility's Procedures shall comply with the following requirements:

2.3.1. Procedures shall include any and all Procedures, standards, strategies, processes, or any documents relied upon by the Utility to identify, propose, authorize, plan, prioritize, budget, or implement any Project included in its Project Spreadsheet.

2.3.2. If not evident from the Procedure document, the Utility shall identify the effective date of the Procedure and the document the Procedure is replacing, if any.

2.3.3. The Utility shall produce and identify for Stakeholders any new or changed Procedures on a semi-annual basis when the updated Project Spreadsheet is provided.

2.4. The Utility shall distribute the semi-annual revisions to the Project Spreadsheet, Authorization Documents, and Procedures on the same date.

3. Opportunities for Inquiry and Comments

3.1. Information Requests and Comments: Stakeholders may submit information requests and comments to the Utility within a 45-calendar day period that begins on the day following the production of semi-annual information identified in Section 2.1. Stakeholders may also submit information requests and/or comments within a 15-calendar day period that begins on the day following a Stakeholder meeting. The Utility will exercise best efforts to respond to the information requests and comments within 15 business days after a Stakeholder's submittal. Should the Utility not be able to respond within 15 business days, the Utility shall notify the CPUC and all Stakeholders in writing of the delay within ten business days of receiving the information request with an explanation of why the 15-business day expectation cannot be met. Any delayed response may affect the ability of Stakeholders and the CPUC to provide Agenda Items for a subsequent Stakeholder meeting 15 days prior to a Stakeholder meeting without reducing the expectation that the Utility will include those Agenda Items in the Stakeholder meeting. Other benchmark dates in the TPR Process may also be affected by any delay in Utility responses.

3.1.1. The scope of the information requests shall relate to the Projects contained in the Project Spreadsheet, Procedures, and Authorization Documents and may include, but are not limited to the following areas of inquiry:

3.1.1.1. More detailed descriptions of the Projects;

3.1.1.2. Procedures related to identifying, proposing, authorizing, planning, prioritizing, budgeting, and implementing Projects;

3.1.1.3. The estimated cost of the Project and the methodology used to arrive at that estimate;

3.1.1.4. More detailed description of a Project's purpose and justification of need, including without limitation and to the extent such information exists:

3.1.1.4.1. Standards, requirements, or policies supporting the need for the proposed Project;

3.1.1.4.2. Any wildfire or safety threat assessment, if available;

3.1.1.4.3. Inspection records or other information regarding the condition of any existing asset related to the proposed Project;

3.1.1.4.4. Technical or other analyses regarding the alternatives considered;

3.1.1.4.5. Any economic analyses (e.g., cost-benefit studies) of the Project; and

3.1.1.4.6. Any analyses or documents used to obtain internal authorization for the Project.

3.1.2. The scope of comments shall relate to Projects included in the Project Spreadsheet, Authorization Documents, or Procedures related to identifying, proposing, authorizing, planning, prioritizing, budgeting, and implementing those Projects.

3.2. If a Stakeholder requests additional Project-specific information from the utility outside the time frames outlined in Section 3.1, the Utility will exercise best efforts to provide responsive information within ten business days of a Stakeholder's request, including, but not limited to: benefit/cost analyses, technical analyses regarding the need for the Project or alternatives considered, and any analyses or documents used to obtain internal authorization for the Project. These project-specific information requests shall relate to previous information requests and/or Utility responses but do not need to be about the same projects previously inquired about. Should the Utility not be able to respond within ten business days, the Utility shall notify in writing the CPUC and all Stakeholders of the delay within five business days after receiving the information request with an explanation of why the ten-business day expectation cannot be met.

3.3. While the TPR Process should provide Stakeholders with substantial information about the Utility's Projects, nothing herein prevents the CPUC or other Stakeholders from seeking further information from the Utility regarding Projects through data or information requests in any other proceedings, whether at the CPUC, the CAISO, FERC, or elsewhere.

4. Stakeholder Meetings

4.1. The Utility shall host a minimum of two Stakeholder meetings annually. The first Stakeholder meeting in a calendar year will include review of the Utility's Project Spreadsheet, objectives, assumptions, and deliverables for the current year and the opportunity for Stakeholders to suggest new projects or project alternatives. The Utility will also report on the prior year's Project implementation and identify and explain modifications to key factors/assumptions relied upon in the prior year. The first Stakeholder meeting in a calendar year will also include the opportunity for Stakeholders to raise and discuss any proposed adjustments to the data being provided.

4.2. Both the first and second Stakeholder meetings in a calendar year will include responding to the CPUC's and Stakeholders' comments and questions related to Projects in the Spreadsheet, Procedures, Authorization Documents, and other related issues identified in advance of the Stakeholder meetings.

4.3. The Utility will have subject matter experts present who can respond to recent comments and questions from the CPUC and Stakeholders. The CPUC and Stakeholders will have the opportunity to provide agenda items no fewer than 15 calendar days before the Stakeholder meeting. The Utility will incorporate these agenda items into the Stakeholder meeting and shall have relevant subject matter experts present at the Stakeholder meeting to address these topics.

5. Stakeholders Have the Ability to Make Use of the Data and Outcomes of the Transmission Project Review Process in Other Proceedings.

5.1. Stakeholders may use the data or other information provided in the TPR Process in multiple fora, including, without limitation, in CPUC, CAISO, FERC, or U.S. Department of Energy proceedings, subject to compliance with confidentiality and/or CEII restrictions.

5.2. Nothing herein precludes a Stakeholder from challenging the designation of a document as confidential or CEII, either before FERC, the CPUC, or a court of competent jurisdiction.

6. Dispute Resolution

6.1. A Stakeholder may bring a dispute under this section for any matter, substantive or procedural, pertaining to the implementation of the TPR Process.

6.2. A dispute will be initiated when a disputing party sends notice to the Utility, with a copy provided to that Utility's TPR Process distribution list, that it is contesting a determination made by the Utility.

6.3. Within 30 calendar days of receipt of a notice of dispute, disputing parties and the Utility will meet and attempt to resolve the dispute. If the disputing parties are unable to resolve the dispute, within 10 calendar days of reaching an impasse, a disputing party may file a "Notice of Dispute" with the CPUC's Executive Director. The Executive Director or designee will review the disputed issue and make a determination resolving the dispute within 30 calendar days of receiving the Notice of Dispute. The determination of the Executive Director or designee shall be served on the filer and Stakeholders. The Executive Director's or designee's determination shall be final.

ATTACHMENT B

E-5252 Draft Transmission Project Review Process Data Template in an Accompanying Excel File.

ATTACHMENT C

The TPR Process will begin on January 2, 2024 for San Diego Gas & Electric. Pacific Gas and Electric and Southern California Edison will have issued comparable publicly accessible data in their FERC-derived Stakeholder Transmission Asset Review Process and Stakeholder Review Process, respectively, on December 1, 2023. PG&E and SCE will begin their participation in the TPR Process with the release of their data in May 2024 and June 2024, respectively.

SCHEDULE FOR TRANSMISSION PROJECT REVIEW PROCESS
Pacific Gas and Electric

November 1[154]: Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.

December 16: Deadline for Stakeholders to provide questions and comments related to the Project Spreadsheet[155] provided on November 1.[156]

January 13: Utility distributes and publishes written responses to the December 15 comments and questions.

January 20: CPUC and Stakeholders provide Agenda Items for upcoming Stakeholder meeting.

February 4 : Utility hosts the first Stakeholder meeting for the TPR Process, to include review of the Utility's most current Project Spreadsheet, objectives, assumptions, and forecasted deliverables for the current year, as well as the opportunity for Stakeholders to identify new Projects or Project alternatives. Utility responds to Stakeholders' new questions, including any follow-up questions from the Utility's responses to Stakeholders on January 6. Starting in year two, the process will also include reporting on the prior year's TPR Process and the Utility's identification and explanation of modifications to key elements and assumptions relied upon in the prior year's TPR

[154] Where a date falls on a holiday or weekend, it will be moved to the next business day. Any subsequent dates will also be adjusted as necessary.

[155] The scope of questions and comments is explained in Section 3 of the TPR Process Description.

[156] To the fullest extent not precluded by privilege or CEII designations, the Utility shall publish and retain for five years all information related to the TPR Process, including Stakeholder questions and comments, the Utility's responses to questions and comments, and any other information related to the TPR Process on its website in an area devoted to this Process.

Process, as well as an opportunity for Stakeholders to raise and discuss any proposed adjustments to the data being provided.

<u>February 19</u>: Stakeholders provide questions and comments within 15 calendar days following the February Stakeholder meeting.

<u>March 13</u>: Utility distributes and publishes written responses to the February comments and questions from Stakeholders.

<u>April 4:</u> Stakeholders may provide comments to the Utility by this date. There is no expectation that the Utility will provide a written response to these comments.

<u>May 1:</u> Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.

<u>June 15</u>: Deadline for Stakeholders to provide questions and comments related to the Project Spreadsheet provided on May 1.

<u>July 7</u>: Utility distributes and publishes written responses to the June 15 comments and questions from Stakeholders and the CPUC.

<u>July 14:</u> CPUC and Stakeholders provide Agenda Items for upcoming Stakeholder meeting.

<u>July 29</u>: Utility hosts second Stakeholder meeting to discuss, without limitation, specific Projects, Project programs, work categories, and procedures; to answer questions related to the contents of the Project Spreadsheet; and to highlight known material updates from the May 1 Project Spreadsheet. Utility will identify and discuss proposed changes impacting the year's Project planning, prioritization, and implementation of Projects.

<u>August 13:</u> Stakeholders provide questions and comments within 15 calendar days following the July Stakeholder meeting.

<u>September 4</u>: Utility distributes and publishes written responses to the August 13 comments and questions from Stakeholders.

<u>September 30:</u> Stakeholders may provide comments to the Utility by this date. There is no expectation that the Utility will provide a written response to these comments.

<u>November 1</u>: Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.

SCHEDULE FOR TRANSMISSION PROJECT REVIEW PROCESS
Southern California Edison

December 1[157]: Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.

January 15: Deadline for Stakeholders to provide questions and comments related to the Project Spreadsheet[158] provided on December 1.[159]

February 6: Utility distributes and publishes written responses to the January 15 comments and questions.

February 13: CPUC and Stakeholders provide Agenda Items for upcoming Stakeholder meeting.

February 28: Utility hosts the first Stakeholder meeting for the TPR Process, to include review of the Utility's most current Project Spreadsheet, objectives, assumptions, and forecasted deliverables for the current year, as well as the opportunity for Stakeholders to identify new Projects or Project alternatives. Utility responds to Stakeholders' new questions, including any follow-up questions from the Utility's responses to Stakeholders on February 6. Starting in year two, the process will also include reporting on the prior year's TPR Process and the Utility's identification and explanation of modifications to key elements and assumptions relied upon in the prior year's TPR Process, as well as an opportunity for Stakeholders to raise and discuss any proposed adjustments to the data being provided.

March 15: Stakeholders provide questions and comments within 15 calendar days following the February Stakeholder meeting.

April 6: Utility distributes and publishes written responses to the March 15 comments and questions from Stakeholders.

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[157] Where a date falls on a holiday or weekend, it will be moved to the next business day. Any subsequent dates will also be adjusted as necessary.

[158] The scope of questions and comments is explained in Section 3 of the TPR Process Description.

[159] To the fullest extent not precluded by privilege or CEII designations, the Utility shall publish and retain for five years all information related to the TPR Process, including Stakeholder questions and comments, the Utility's responses to questions and comments, and any other information related to the TPR Process on its website in an area devoted to this Process.

April 30: Stakeholders may provide comments to the Utility by this date. There is no expectation that the Utility will provide a written response to these comments.

June 1: Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.

July 16: Deadline for Stakeholders to provide questions and comments related to the Project Spreadsheet provided on June 1.

August 6: Utility distributes and publishes written responses to the July 16 comments and questions from Stakeholders.

August 13: CPUC and Stakeholders provide Agenda Items for upcoming Stakeholder meeting.

August 28: Utility hosts second Stakeholder meeting to discuss, without limitation, specific Projects, Project programs, work categories, and procedures; to answer questions related to the contents of the Project Spreadsheet; and to highlight known material updates from the June 1 Project Spreadsheet. Utility will identify and discuss proposed changes impacting the year's Project planning, prioritization, and implementation of Projects.

September 12: Stakeholders provide questions and comments within 15 calendar days following the August Stakeholder meeting.

October 3: Utility distributes and publishes written responses to the September 12 comments and questions from Stakeholders.

October 31: Stakeholders may provide comments to the Utility by this date. There is no expectation that the Utility will provide a written response to these comments.

December 1: Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.

SCHEDULE FOR TRANSMISSION PROJECT REVIEW PROCESS
San Diego Gas & Electric

January 2[160]: Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.

February 16: Deadline for Stakeholders to provide questions and comments related to the Project Spreadsheet[161] provided on January 2.[162]

March 10: Utility distributes and publishes written responses to the February 16 comments and questions.

March 17: CPUC and Stakeholders provide Agenda Items for upcoming Stakeholder meeting.

April 1: Utility hosts the first Stakeholder meeting for the TPR Process, to include review of the Utility's most current Project Spreadsheet, objectives, assumptions, and forecasted deliverables for the current year, as well as the opportunity for Stakeholders to identify new Projects or Project alternatives. Utility responds to Stakeholders' new questions, including any follow-up questions from the Utility's responses to Stakeholders on March 10. Starting in year two, the process will also include reporting on the prior year's TPR Process and the Utility's identification and explanation of modifications to key elements and assumptions relied upon in the prior year's TPR Process, as well as an opportunity for Stakeholders to raise and discuss any proposed adjustments to the data being provided.

April 16: Stakeholders provide questions and comments within 15 calendar days following the April Stakeholder meeting.

May 7: Utility distributes and publishes written responses to the mid-April comments and questions from Stakeholders.

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[160] Where a date falls on a holiday or weekend, it will be moved to the next business day. Any subsequent dates will also be adjusted as necessary.

[161] The scope of questions and comments is explained in Section 3 of the TPR Process Description.

[162] To the fullest extent not precluded by privilege or CEII designations, the Utility shall publish and retain for five years all information related to the TPR Process, including Stakeholder questions and comments, the Utility's responses to questions and comments, and any other information related to the TPR Process on its website in an area devoted to this Process.

May 31: Stakeholders may provide comments to the Utility by this date. There is no expectation that the Utility will provide a written response to these comments.

July 1: Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.

August 15: Deadline for Stakeholders to provide questions and comments related to the Project Spreadsheet provided on July 1.

September 6: Utility distributes and publishes written responses to the August 15 comments and questions from Stakeholders.

September 13: CPUC and Stakeholders provide Agenda Items for upcoming Stakeholder meeting.

September 28: Utility hosts second Stakeholder meeting to discuss, without limitation, specific Projects, Project programs, work categories, and procedures; to answer questions related to the contents of the Project Spreadsheet; and to highlight known material updates from the July 1 Project Spreadsheet. Utility will identify and discuss proposed changes impacting the year's Project planning, prioritization, and implementation of Projects.

October 13: Stakeholders provide questions and comments within 15 calendar days following the September Stakeholder meeting.

November 3: Utility distributes and publishes written responses to the October 13 comments and questions from Stakeholders.

November 30: Stakeholders may provide comments to the Utility by this date. There is no expectation that the Utility will provide a written response to these comments.

January 2: Utility releases semi-annual Project Spreadsheet, Authorization Documents, and Procedures.