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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Agenda ID #21245

ENERGY DIVISION **RESOLUTION E-5252**

February 2, 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 Utility 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")[1] beginning January 1, 2024. The purpose in establishing the TPR Process is to devise a uniform process to review IOUs'

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

capital transmission projects with the goals of providing clarity 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]; inquire about, and provide feedback on the IOUs' historical, current, and forecast transmission projects; and provide feedback to the IOUs' on their 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 by the CAISO or the Commission,[3] and over the last three years, these Utility Self-Approved ("self-approved") Projects have 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] 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 assessment process, which includes an annual release of transmission project data, a Stakeholder inquiry period, and an annual Stakeholder meeting. All three processes are currently set to expire by the end of 2023.

$6.6 billion of capital additions added to the three TOs' transmission rate bases.[4] 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[5] of investment in new transmission capacity on the high voltage transmission system will be needed to meet the state's clean energy goals.[6]

Most 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 any capital additions to rate base in the last five years, and any forecast or actual capital expenditures in the current year or future five 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 one million dollars 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 will have the opportunity to provide questions and comments,

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[4] These numbers are based on the utilities' responses in July 2021 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.

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

[6] 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 40% of the costs of operating the CAISO controlled transmission grid.

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.[7] 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.[8]

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.[9] 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.[10] Further, pursuant to Public Utilities Code

[7] *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.")

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

[9] Pub. Util. Code § 701.

[10] 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. The Commission has the authority to "at any time, inspect the accounts, books, papers, and documents of any public utility."[11] The Commission may "examine under oath any officer, agent, or employee of a public utility in relation to its business and affairs."[12] 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."[13] 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."[14] 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.[15]

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 have revealed that the IOUs' procedures for planning and prioritizing projects are

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[11] Pub. Util. Code § 314(a).

[12] *Id*.

[13] Pub. Util. Code § 581.

[14] *Id*.

[15] 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 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 is not part of transmission planning or rate recovery stages, which both fall under FERC's jurisdiction.

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.

<u>Current Stakeholder Processes are Inconsistent and Temporary</u>

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.[16] 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 one million dollars 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 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 Evaluation of Capital Additions is far less comprehensive. While the STAR Process and SRP are temporary and inconsistent, they have provided useful information for the

[16] 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). The settlement language filed at FERC for these three processes is attached to this OIR as Appendix A.

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 by the CAISO or the Commission, and over the last three years Utility Self-Approved Projects have 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 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.

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 to provide Stakeholders with transparency of transmission network upgrades.

Numerous Commission Programs and Proceedings Benefit from Robust Transmission Data.

The TPR 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 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 this Distributed Energy Resources ("DER") Action Plan is to ensure that DER policy implementation in support of SB 100[17] 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 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 GHG reduction, renewable integration, and grid optimization. One of the potential services that energy storage can provide is deferral of transmission development. Access to timely

[17] 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.

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 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"[18] 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 how each transmission owner has applied the most current RDF to each project.

NOTICE

This Draft Resolution is being 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.

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

[18] 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)

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 will include:

- Robust, consistent, and ongoing data and Authorization Documents to ensure sufficient transparency of Utilities' transmission projects, including generator interconnection-related network upgrades. The TPR 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 regardless of whether they are Projects reviewed in the CAISO's Transmission Planning Process or are Utility Self-Approved Projects. 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 any entity with an interest in electric transmission development, service, and/or rates in the CAISO control area. All Stakeholders will have access to the publicly available information. Pursuant to CPUC or FERC limitations, not all

Stakeholders will have access to confidential information or critical electric/energy infrastructure information ("CEII") included in the TPR Process.

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 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 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 one million dollars or more, regardless of whether they were included in the CAISO's Transmission Planning Process. 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 five-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 through a secure portal on each Utility's website. Access to the secure portal will require a signed non-disclosure agreement. Each Utility will submit its proposed non-disclosure agreement to Energy Division for approval via advice letter.

Procedures refer to those processes, procedures, strategies 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 and Procedures 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 shall respond to the information requests and comments within 15 business days after the CPUC or a Stakeholder submits them to the Utility.

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. The Utility 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 determining 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.

DISPUTE RESOLUTION

In the event of substantive and procedural disagreements that are not easily resolved in the TPR Process, the matter will be referred to Energy Division for a determination.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this Draft Resolution must be subject to at least 30 days public review and comment prior to a vote of the Commission. Accordingly, this Draft Resolution was mailed for comments 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.

All comments on the Draft Resolution must be received by the Energy Division by January 12, 2023. Comments shall be limited to fifteen pages in length and should list the recommended changes to the Draft Resolution. Comments shall focus on factual, legal, or technical errors in the proposed Draft Resolution.

Replies to comments will not be accepted.

This Draft Resolution will be placed on the Commission's agenda to be voted on no sooner than 30 days after mailing.

FINDINGS AND CONCLUSIONS

1. The majority of electric transmission capital projects are not reviewed in any formal way 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,

opportunities for inquiry and comments by the CPUC and Stakeholders, and Stakeholder Meetings.

5. Benefits from the TPR Process include more efficient and cost-effective transmission Projects, including generator interconnection-related transmission network upgrades that have long-term benefits.
6. 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.
7. 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 Process shall begin on January 1, 2024, as described in this Resolution and related Attachments.

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 February 2, 2023; the following Commissioners voting favorably thereon:

____

Rachel Peterson
Executive Director

ATTACHMENT A

DRAFT 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."[19] 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. 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. While rarely used, FERC also has the authority to evaluate the prudency of electric transmission Project costs and expenses and to determine whether costs would result in rates that are not just and reasonable.

1.5. Generator Interconnection and Deliverability Allocation Procedures (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.

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

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

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

1.8. Procedures: Processes, procedures, strategies 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.

1.9. 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. A Project would include all of the components of a specifically identified Project, as well as programmatic or "blanket" work categories.

1.10. Project Spreadsheet: Provided to the CPUC and Stakeholders semi-annually, the Project Spreadsheet shall 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. Project-specific data 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 five-year period.

1.11. Stakeholder: Any entity with an interest in electric transmission development, service, and/or rates in the CAISO control area. Pursuant to CPUC or FERC limitations, not all Stakeholders will have access to confidential information or critical electric/energy infrastructure information (CEII) included in the TPR Process.

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

1.13. 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.

1.14. 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 and Procedures, and the 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.

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

1.16. 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 Project Spreadsheet containing the Project-specific data identified in Attachment B to the Resolution for all electric transmission Projects as defined in Section 1.9 above. For any project meeting those criteria, the Project Spreadsheet must be fully populated for each Project.

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, 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 additions in the prior five calendar years.

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 five years.

2.1.4. The data in the Project Spreadsheet shall be as complete, accurate, and verifiable as possible.

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, and any changes to the previously distributed Project Spreadsheet.

2.1.7. There shall be both a public version and 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 confidential data and Critical Energy Infrastructure Information ("CEII") redacted.

2.1.8. Information that is confidential or designated as CEII shall be provided to certain Stakeholders pursuant to CPUC and FERC limitations through a secure portal on each Utility's website. Access to the secure portal will require a signed non-disclosure agreement. Each Utility will submit its proposed non-disclosure agreement to Energy Division for approval via advice letter no later than June 30, 2023.

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.

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 process, procedures, and strategy 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 shall respond to the information requests and comments within 15 business days after a Stakeholder's submittal.

3.1.1. The scope of the information requests shall relate to the Projects contained in the Project Spreadsheet 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 shall 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.

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 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.

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, 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 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 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 30 days of such meeting, the issue will be referred to Energy Division for a determination in the matter.

ATTACHMENT B

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

ATTACHMENT C

DRAFT SCHEDULE FOR TRANSMISSION PROJECT REVIEW PROCESS, TO #1

November 1[20]: Utility releases semi-annual Project Spreadsheet, which should correspond with the Utility's Formula Rate or Annual Update filing at FERC for the following rate year in its TO rate case.

December 15: Deadline for Stakeholders to provide questions and comments related to the Project Spreadsheet[21] provided on November 1.[22]

January 1: Utility distributes and publishes written responses to the December 15 comments and questions.

February 1-7: 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 1. 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.

February 15-21: Stakeholders provide questions and comments within 14 days following the February Stakeholder meeting.

March 15: Utility distributes and publishes written responses to the mid-February comments and questions from Stakeholders.

April 1: 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.

May 1: Utility releases semi-annual TPR Process Spreadsheet, which should correspond

[20] Where a date falls on a holiday or weekend, it will be moved to the next business day.

[21] The scope of questions and comments is explained in Section 2.4 of the TPR Process.

[22] To the fullest extent not precluded by privilege or CEII designations, the Utility shall publish and retain for ten 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.

with the capital Projects in the Utility's Draft Annual Update for the following rate year in its TO rate case at FERC.

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

July 1: Utility distributes and publishes written responses to the June 15 comments and questions from Stakeholders.

August 1-7: 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.

August 15: Stakeholders provide questions and comments within 14 days following the August Stakeholder meeting.

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

October 1: 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.

November 1: Utility releases semi-annual Project Spreadsheet, which should correspond with the Utility's Formula Rate or Annual Update filing at FERC for the following rate year in its TO rate case.

PROPOSED SCHEDULE FOR TRANSMISSION PROJECT REVIEW PROCESS TO #2

December 1[23]: Utility releases semi-annual Project Spreadsheet, which should correspond with the Utility's Formula Rate or Annual Update filing at FERC for the following rate year in its TO rate case.

January 15: Deadline for Stakeholders to provide questions and comments related to the

[23] Where a date falls on a holiday or weekend, it will be moved to the next business day.

Project Spreadsheet[24] provided on December 1.[25]

February 1: Utility distributes and publishes written responses to the January 15 comments and questions.

March 1-7: 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 1. 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.

March 15-21: Stakeholders provide questions and comments within 14 days following the March Stakeholder meeting.

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

May 1: 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 TPR Process Spreadsheet, which should correspond with the capital Projects in the Utility's Draft Annual Update for the following rate year in its TO rate case at FERC.

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

August 1: Utility distributes and publishes written responses to the July 15 comments and questions from Stakeholders.

September 1-7: Utility hosts second Stakeholder meeting to discuss, without limitation, specific Projects, Project programs, work categories, and procedures; to answer

[24] The scope of questions and comments is explained in Section 2.4 of the TPR Process.

[25] To the fullest extent not precluded by privilege or CEII designations, the Utility shall publish and retain for ten 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.

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 15-21: Stakeholders provide questions and comments within 14 days following the September Stakeholder meeting.

October 15: Utility distributes and publishes written responses to the mid-September comments and questions from Stakeholders.

November 1: 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, which should correspond with the Utility's Formula Rate or Annual Update filing at FERC for the following rate year in its TO rate case.

PROPOSED SCHEDULE FOR TRANSMISSION PROJECT REVIEW PROCESS TO #3

January 1[26]: Utility releases semi-annual Project Spreadsheet, which should correspond with the Utility's Formula Rate or Annual Update filing at FERC for the following rate year in its TO rate case.

February 15: Deadline for Stakeholders to provide questions and comments related to the Project Spreadsheet[27] provided on January 1.[28]

March 1: Utility distributes and publishes written responses to the February 15 comments and questions.

April 1-7: 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

[26] Where a date falls on a holiday or weekend, it will be moved to the next business day.

[27] The scope of questions and comments is explained in Section 2.4 of the TPR Process.

[28] To the fullest extent not precluded by privilege or CEII designations, the Utility shall publish and retain for ten 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.

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 1. 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.

April 15-21: Stakeholders provide questions and comments within 14 days following the April Stakeholder meeting.

May 15: Utility distributes and publishes written responses to the mid-April comments and questions from Stakeholders.

June 1: 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 TPR Process Spreadsheet, which should correspond with the capital Projects in the Utility's Draft Annual Update for the following rate year in its TO rate case at FERC.

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

September 1: Utility distributes and publishes written responses to the August 15 comments and questions from Stakeholders.

October 1-7: 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 15-21: Stakeholders provide questions and comments within 14 days following the October Stakeholder meeting.

November 15: Utility distributes and publishes written responses to the mid-October comments and questions from Stakeholders.

December 1: 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 1: Utility releases semi-annual Project Spreadsheet, which should correspond with the Utility's Formula Rate or Annual Update filing at FERC for the following rate year in its TO rate case.