PACIFIC GAS AND ELECTRIC COMPANY

Transmission Owner Tariff (TO Tariff)

FERC Electric Tariff Volume No. 5

Effective: January 1, 2024

Table of Contents

1. Preamble

The Participating TO's revenue requirements and applicable rates and charges for transmission access and transmission reliability services over the ISO Controlled Grid and the terms and conditions for transmission expansion and interconnection are set forth in this TO Tariff and the ISO Tariff.

1.1 Transmission Access for Participating TOs

Participating TOs are able to participate in the ISO and utilize the entire ISO Controlled Grid to serve their End-Use Customers. The applicable High Voltage Access Charges and Transition Charges shall be paid by Participating TOs to the ISO pursuant to the ISO Tariff. If a Participating TO utilizes the Low Voltage Transmission Facilities of another Participating TO, the Participating TO shall also pay the Low Voltage Access Charge of the other Participating TO.

1.2 Transmission Access for Wheeling Customers

Wheeling allows Scheduling Coordinators to deliver Energy through or out of the ISO Controlled Grid to serve a load located outside the transmission or Distribution System of a Participating TO. Wheeling Access Charges shall be paid by Scheduling Coordinators to the ISO pursuant to the ISO Tariff.

1.3 Transmission Access for End-Users

End-Users receive transmission service over the ISO Controlled Grid through the Participating TO to whose transmission or distribution facilities the End-User is directly connected. Charges to End-Users for access to the ISO Controlled Grid shall be paid to the applicable Participating TO to whose transmission or distribution facilities the End-User is directly connected.

1.4 Transmission Reliability Service

All TO Tariff End-Use and Wholesale Customers shall pay transmission Reliability Service Charges to the Participating TO or the ISO as the Participating TO's agent, as provided in Section 5.6 of this TO Tariff.

2. Termination

This TO Tariff may be terminated by the Participating TO upon such advance notice and with such authorization as FERC may require.

3. TO Definitions

Capitalized terms used in this TO Tariff shall have the meanings set out below unless otherwise stated or the context otherwise requires. Capitalized terms used in this Tariff and not defined below shall have the meanings set out in the ISO Tariff.

3.1 Access Charge

A charge paid by all UDCs, MSSs and, in certain cases, Scheduling Coordinators delivering Energy to Gross Load, as set forth in Section 26.1 of the ISO Tariff. The Access Charge includes the High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge, as applicable.

3.2 AGC

Generation equipment that automatically responds to signals from the ISO's EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.

3.3 Ancillary Services

Regulation, Spinning Reserve, Non-Spinning Reserve,Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.

3.4 Applicable Reliability Criteria

The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the Nuclear Regulatory Commission.

3.5 Available Transfer Capacity

For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WSCC transmission capacity rating guidelines, less any reserved uses applicable to the path.

3.6 Base Transmission Revenue Requirement

The Transmission Revenue Requirement which does not reflect amounts for the Transmission Revenue Balancing Account Adjustment (TRBAA), Standby Transmission Demand Revenues or the Reliability Services Balancing Account (RSBA).

3.7 Black Start

The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts.

3.8 Business Day

A day on which banks are open to conduct general banking business in California.

3.9 Completed Application Date

The date on which a party submits an Interconnection Application that satisfies the requirements of a Completed Interconnection Application.

3.10 Completed Interconnection Application

An Interconnection Application that satisfies all of the information and other requirements of Section 10.3 of this TO Tariff.

3.11 Congestion

A condition that occurs when there is insufficient Available Transfer Capacity to implement all Preferred Schedules simultaneously or, in real-time, to serve all Generation and Demand. "Congested" shall be construed accordingly

3.12 Congestion Management

The alleviation of Congestion in accordance with applicable ISO Protocols and Good Utility Practice.

3.13 Converted Rights

Those transmission service rights defined in Section 4.3.1.6 of the ISO Tariff.

3.14 CPUC

The California Public Utilities Commission, or its successor.

3.15 [Omitted]

3.16 Demand

The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000 W = 1 kW, 1,000 kW = 1 MW, etc.

3.17 Direct Assignment Facilities

Facilities or portions of facilities that are owned by the Participating TO necessary to physically and electrically interconnect a particular party requesting Interconnection under this

TO Tariff to the ISO Controlled Grid at the point of interconnection. Direct Assignment Facilities shall be specified in the Interconnection Agreement that governs Interconnection service to such party and shall be subject to FERC approval.

3.18 Dispatch

The operating control of an integrated electric system to: i) assign specific Generation Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls; ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; iii) operate interconnections; iv) manage Energy transactions with other interconnected Control Areas; and v) curtail Demand.

3.19 Distribution System

The distribution assets of a TO, UDC or MSS.

3.20 Eligible Customer

(i) Any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.

3.21 Encumbrance

A legal restriction or covenant binding on the Participating TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO

Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date.

3.22 End-Use Customer or End-User

A purchaser of electric power who purchases such power to satisfy a Load directly connected to the ISO Controlled Grid or to a Distribution System and who does not resell the power.

3.23 End-Use Customer Refund Balancing Account Adjustment

A mechanism established by the Participating TO, which will ensure that End-Use Customers receive a credit or charge equal to the refund or surcharge, including interest, related to refunds ordered by the Commission.

3.24 Energy

The electrical energy produced, flowing, or supplied by generation, transmission, or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh = 1 kWh, 1,000 kWh = 1 MW, etc.

3.25 Entitlement

The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.

3.26 Existing Contracts

The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.

3.27 Existing Rights

Those transmission service rights defined in Section 16.1 of the ISO Tariff.

3.28 Expedited Interconnection Agreement

A contract between a party which has submitted a Request for Expedited Interconnection Procedures and the Participating TO under which the Participating TO agrees to process, on an expedited basis, the Completed Interconnection Application of such party and which sets forth the terms, conditions, and cost responsibilities for such interconnection.

3.29 Facilities Study Agreement

An agreement between a Participating TO and either a party requesting Interconnection to the ISO Controlled Grid, Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the party requesting such Interconnection, Market Participants, Project Sponsor, or identified principal beneficiaries agrees to reimburse the Participating TO for the cost of performing or reviewing a Facilities Study.

3.30 Facility or Facilities Study

An engineering study conducted to determine required modifications to the Participating TO's transmission system, including the estimated cost and scheduled completion date for such modifications that will be required to provide needed services.

3.31 FERC

The Federal Energy Regulatory Commission, or its successor.

3.32 FPA

The Federal Power Act, 16 U.S.C. § 791a et seq., as it may be amended from time to time.

3.33 [Omitted]

3.34 Generating Unit

An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is: (a) located within the ISO Control Area; (b) connected to the ISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities; and (c) that is capable of producing and delivering net Energy (Energy in excess of a generating station's internal power requirements).

3.35 Generation

Energy delivered from a Generating Unit.

3.36 Good Utility Practice

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region

3.37 Gross Load

All Energy (adjusted for distribution losses) delivered for the supply of End-User Loads directly connected to the transmission facilities or Distribution System of the Participating TO. Gross Load shall exclude the portion of the Load of an individual End-Use Customer of the Participating TO that is served by a Generating Unit that: (a) is located on the customer's site or provides service to the customer's site through over-the-fence arrangements as authorized by Section 218 of the California Public Utilities Code; (b) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in the FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; (c) was serving the customer's Load on or before March 31, 2000; and (d) secured Standby Service from the Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, as of March 31, 2000 and continues to secure Standby Service from the Participating TO or can be curtailed concurrently with an outage of the Generating Unit serving the Load.

3.38 High Voltage Access Charge

A component of the Access Charge determined by the ISO under Section 26.1 of the ISO Tariff.

3.39 High Voltage Transmission Facility

A transmission facility under the operational control of the ISO that is owned by the Participating TO or to which the Participating TO has an Entitlement that may be associated with a Converted Right, which operates at a voltage at or above 200 kilovolts, and supporting facilities, and the costs of which are not directly assigned to one or more specific customers.

3.40 High Voltage Transmission Revenue Requirement

The portion of the Participating TO's TRR associated with and allocable to the Participating TO's High Voltage Transmission Facilities and Converted Rights associated with High Voltage Transmission Facilities.

3.41 High Voltage Utility-Specific Rate

The Participating TO's High Voltage Transmission Revenue Requirement divided by the Participating TO's forecast of its Gross Load.

3.42 High Voltage Wheeling Access Charge

The Wheeling Access Charge assessed by the ISO associated with the recovery of the Participating TO's High Voltage Transmission Revenue Requirement in accordance with Section 26.1 of the ISO Tariff.

3.43 [Omitted]

3.44 Interconnection

Transmission facilities, other than additions or replacements to existing facilities that: i) connect one system to another system where the facilities emerge from one and only one substation of the two systems and are functionally separate from the ISO Controlled Grid facilities such that the facilities are, or can be, operated and planned as a single facility; or ii) are identified as radial transmission lines pursuant to contract; or iii) produce Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not owned by the Participating TO, would result in a reduction in the ISO's Operational Control of the Participating TO's portion of the ISO Controlled Grid.

3.45 Interconnection Agreement

A contract between a party requesting Interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.

3.46 Interconnection Application

An application that requests Interconnection to the ISO Controlled Grid.

3.47 Interest

Interest shall be calculated in accordance with the methodology specified for interest on refunds in the regulations of FERC at 18 C.F.R. § 35.19a(a)(2)(iii) (2000). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt.

3.48 Independent System Operator ("ISO")

The California Independent System Operator Corporation, a state chartered, nonprofit corporation that controls the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads.

3.49 ISO ADR Procedures

The procedures for resolution of disputes or differences set out in Section 13 of the ISO Tariff, as amended from time to time.

3.50 ISO Controlled Grid

The system of transmission lines and associated facilities of the Participating TOs that have been placed under the ISO's Operational Control.

3.51 ISO Protocols

The rules, protocols, procedures and standards attached to the ISO Tariff and Appendix L, promulgated by the ISO (as amended from time to time) to be complied with by the ISO Scheduling Coordinators, Participating TOs and all other Market Participants in relation to the operation of the ISO Controlled Grid and the participation in the markets for Energy and Ancillary Services in accordance with the ISO Tariff.

3.52 ISO Tariff

The California Independent System Operator Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.

3.53 Load

An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.

3.54 Local Furnishing Bond

Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).

3.55 Local Furnishing Participating TO

Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.

3.56 Local Publicly Owned Electric Utilities

A municipality or municipal corporation operating as a public utility furnishing electric service, a municipal utility district furnishing electric service, a public utility district furnishing electric services, an irrigation district furnishing electric services, or a joint powers authority that includes one or more of these agencies and that owns Generation or transmission facilities, or furnishes electric services over its own or its members' electric Distribution System.

3.57 Local Regulatory Authority

The state or local governmental authority responsible for the regulation or oversight of a utility.

3.58 Local Reliability Criteria

Reliability criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.

3.59 Low Voltage Access Charge

The Access Charge applicable under Section 26.1 of the ISO Tariff to recover the Low Voltage Transmission Revenue Requirement of the Participating TO.

3.60 Low Voltage Transmission Facility

A transmission facility under the operational control of the ISO owned by the Participating TO or to which the Participating TO has an Entitlement that may be represented by a Converted Right, which is not a High Voltage Transmission Facility, and supporting facilities, and the costs of which are not directly assigned to one or more specific customers.

3.61 Low Voltage Transmission Revenue Requirement

The portion of the Participating TO's TRR associated with and allocable to the Participating TO's Low Voltage Transmission Facilities and Converted Rights associated with Low Voltage Transmission Facilities.

3.62 Low Voltage Wheeling Access Charge

The Wheeling Access Charge associated with the recovery of the Participating TO's Low Voltage Transmission Revenue Requirement in accordance with Section 26.1 of the ISO Tariff.

3.63 Market Participant

An entity, including a Scheduling Coordinator, who participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid.

3.64 MSS (Metered Subsystem)

A geographically contiguous system, located within a single zone which has been operating as an electric utility for a number of years prior to the ISO Operations Date as a municipal utility, water district, irrigation district, state agency or federal power marketing authority subsumed within the ISO Balancing Authority Area and encompassed by ISO certified revenue quality meters at each interface point with the ISO Controlled Grid and ISO-certified revenue quality meters on all Generating Units or, if aggregated, each individual resource and Participating Load internal to the system, which is operated in accordance with a MSS agreement described in Section 4.9.1 of the ISO Tariff.

3.65 NERC

The North American Electric Reliability Council or its successor.

3.66 [Omitted]

3.67 [Omitted]

3.68 New High Voltage Transmission Facility

A High Voltage Transmission Facility of the Participating TO that enters service on or after the Transition Date described in Section 4 of Appendix F, Schedule 3 of the ISO Tariff, or a capital addition made on or after the Transition Date described in Section 4.1 of Appendix F, Schedule 3 of the ISO Tariff to a High Voltage Transmission Facility that existed prior to the Transition Date.

3.69 New Participating TO

A Participating TO that is not an Original Participating TO.

3.70 Non-Participating TO

A TO that is not a party to the TCA or for the purposes of Sections 16.1 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.

3.71 Non-Spinning Reserve

The portion of off-line generating capacity that is capable of being synchronized and ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours.

3.72 Operational Control

The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.

3.73 Original Participating TO

A Participating TO that was a Participating TO as of January 1, 2000. The Original Participating TOs are Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company.

3.74 Participating TO

A party to the TCA whose application under Section 2.2 of the TCA has been accepted and who has placed its transmission assets and Entitlements under the ISO's Operational Control in accordance with the TCA. A Participating TO may be an Original Participating TO or a New Participating TO. For purposes of this TO Tariff, the Participating TO is Pacific Gas and Electric Company.

3.75 Participation Agreement

An agreement between a Participating TO and a Project Sponsor that specifies the terms and conditions under which the Participating TO will construct a transmission addition or upgrade on behalf of the Project Sponsor.

3.76 Physical Scheduling Plant

A group of two or more related Generating Units, each of which is individually capable of producing Energy, but which either by physical necessity or operational design must be operated as if they were a single Generating Unit and any Generating Unit or Units containing related multiple generating components which meet one or more of the following criteria: i) multiple generating components are related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; ii) the Energy production from one component necessarily causes Energy production from other components; iii) the operational arrangement of related multiple generating components determines the overall physical efficiency of the combined output of all components; iv) the level of coordination required to schedule individual generating components would cause the ISO to incur scheduling costs far in excess of the benefits of having scheduled such individual components separately; or v) metered output is available only for the combined output of related multiple generation components and separate generating component metering is either impractical or economically inefficient.

3.77 [Omitted]

3.78 Project Proponent

A Market Participant or group of Market Participants that: (i) advocates a transmission addition or upgrade; (ii) is unwilling to pay the full cost of the proposed transmission addition and upgrade, and thus is not a Project Sponsor; and (iii) initiates proceedings under the ISO ADR Procedures to determine the need for the proposed transmission addition or upgrade.

3.79 Project Sponsor

A Market Participant or group of Market Participants or a Participating TO that proposes the construction of a transmission addition or upgrade in accordance with Section 24 of the ISO Tariff.

3.80 Regional Transmission Group ("RTG")

A voluntary organization approved by FERC and composed of transmission owners, transmission users, and other entities, organized to efficiently coordinate the planning, expansion and use of transmission on a regional and inter-regional basis.

3.81 Regulation

The service provided either by Generating Units certified by the ISO as equipped and capable of responding to the ISO's direct digital control (AGC) signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Balancing Authority Area, in an upward and downward direction to match, on a Real Time basis, Demand and resources, consistent with established NERC and WSCC reliability standards, including any requirements of the NRC. Regulation is used to control the Power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other so as to maintain the target system frequency and/or the established Interchange with other Balancing Authority Areas within the predetermined Regulation Limits. Regulation includes both the increase of output by a Generating Unit or System Resource (Regulation Up) and the decrease in output by a Generating Unit or System Resource (Regulation Down). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and ASMPs in each Settlement Period.

3.82 Reliability Criteria

Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.

3.83 Reliability Services Balancing Account ("RSBA")

A mechanism to ensure that all transmission related Reliability Services Costs, as that term is defined in the Master Definitions Supplement, Appendix A to the currently effective ISO Tariff, which are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area and whose costs are billed to the Participating TO by the ISO pursuant to the ISO Tariff, are allocated to and received from End-Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments apply), withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system.

3.84 Reliability Services Charge

A charge paid by End Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule, whichever is applicable, withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system, as set forth in Section 15 of this TO Tariff. The Reliability Services Charge will recover the Participating TO's reliability services costs, as annually calculated from the balance in the RSBA and a forecast of Reliability Services costs for the following year, from End Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments) applies. In order to mitigate the initial rate increase Wholesale Customers will experience from these Reliability Services Charges, the otherwise applicable Reliability Services Charge will be multiplied by a factor of one-third (1/3) until December 31, 2001, and a factor of two-thirds (2/3) from January 1, 2002 until December 31, 2002. Any Reliability Services costs that are not collected from either TO Tariff Wholesale Customers or Existing Contract customers to which PG&E's Reliability Services Tariff (or reliability services-related contract amendments) applies, prior to December 31, 2002, due to the mitigation described above will be allocated to and collected from End Use Customers. Additionally, if FERC, should disallow recovery of any Reliability Services costs from Wholesale Customers those costs shall be included in the allocation to End Use Customers.

3.85 Reliability Upgrade

The transmission facilities, other than Direct Assignment Facilities, beyond the first point of Interconnection necessary to interconnect a wholesale load safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the Interconnection of a wholesale load, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a wholesale load to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WSCC practice, the facilities necessary to mitigate any adverse impact a wholesale load's interconnection may have on a path's WSCC path rating. Reliability Upgrades shall be specified in the Interconnection Agreement that governs Interconnection service to the wholesale load and shall be subject to FERC approval.

3.86 [Omitted]

3.87 Request for Expedited Interconnection Procedures

A written request by which an applicant for Interconnection can request expedited processing of its Interconnection Application.

3.88 Scheduling Coordinator

An entity certified by the ISO for the purposes of undertaking the functions specified in Section 4.5.3 of the ISO Tariff.

3.89 Scheduling Point

A location at which the ISO Controlled Grid or a transmission facility owned by a Transmission Ownership Right holder is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control.

3.90 Standby Service

Service provided by the Participating TO which allows a Standby Service Customer, among other things, access to High Voltage Transmission Facilities for the delivery of backup power on an instantaneous basis to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit serving the customer's Load.

3.91 Standby Service Customer

A retail End-Use Customer of the Participating TO that receives Standby Service and pays a Standby Rate.

3.92 Standby Transmission Demand Rate

The Demand portion of a rate assessed a Standby Service Customer by the Participating TO, as approved by the Local Regulatory Authority or FERC, as applicable, for Standby Service which compensates the Participating TO for, among other things, costs of High Voltage Transmission Facilities.

3.93 Standby Transmission Demand Revenue

The transmission revenue associated with the demand portion of Standby Service rates collected by the Participating TO from those Standby Service Customers who are not billed for Standby Service on a Gross Load basis.

3.94 Spinning Reserve

The portion of unloaded synchronized generating capacity, that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours.

3.95 System Impact Study

An engineering study conducted to determine whether a request for Interconnection to the ISO Controlled Grid would require new transmission additions, upgrades, or other mitigation measures.

3.96 System Impact Study Agreement

An agreement between a Participating TO and an entity that has requested Interconnection to the Participating TO's transmission system pursuant to which the entity requesting Interconnection agrees to reimburse the Participating TO for the cost of performing or reviewing a System Impact Study.

3.97 TO Tariff

This Transmission Owner Tariff, as it may be amended or superseded.

3.98 Transition Charge

A component of the Access Charge determined by the ISO and assessed the Participating TO along with the High Voltage Access Charge in accordance with Section 5.7 of Appendix F, Schedule 3 of the ISO Tariff.

3.99 Transition Costs

Meaning as set forth in Sections 367, 368, 375, 376, 379, and 840 of the California Public Utilities Code, as enacted as part of AB 1890.

3.100 Transmission Access Charge Balancing Account Adjustment

A mechanism established by the Participating TO which will ensure that the difference between (i) the actual charges by the ISO pursuant to Section 26.1.2 of the ISO Tariff for the High Voltage Access Charge and Transition Charge and (ii) the revenues disbursed by the ISO pursuant to Section 26.1.3 of the ISO Tariff are recovered from the Participating TO's End-Use Customers.

3.101 Transmission Control Agreement ("TCA")

The agreement between the ISO and Participating TOs establishing the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities, as may be modified from time to time.

3.102 Transmission Owner ("TO")

An entity owning transmission facilities or having firm contractual rights to use transmission facilities.

3.103 Transmission Revenue Balancing Account Adjustment ("TRBAA")

A mechanism established by the Participating TO which will ensure that all Transmission Revenue Credits flow through to or are received from End-Use Customers. The TRBAA will also ensure that Transmission Revenue Credits and other credits specified in Section 6, 8, and 13 of Appendix F, Schedule 3 of the ISO Tariff, flow through to other Participating TOs and Wheeling customers for purposes of calculating the High Voltage Access Charge, Low Voltage Access Charge, High Voltage Wheeling Access Charge, Low Voltage Wheeling Access Charge and High Voltage Utility-Specific Access Charge. The TRBAA will also include an adjustment for recovery of any abandonment costs amounts approved by the Commission in connection with the Canada to Northern California transmission project, as contemplated in the Commission's April, 2008 Order on Petition for Declaratory Order in Docket No. EL08-24.

3.104 Transmission Revenue Credit

The proceeds received from the ISO and charges imposed by the ISO that are received and paid by the Participating TO in its role as a Participating TO, as defined by "Transmission Revenue Credit" in the Master Definitions Supplement, Appendix A to the currently effective ISO Tariff.

3.105 Transmission Revenue Requirement ("TRR")

The total annual authorized revenue requirement associated with transmission facilities and Entitlements turned over to the Operational Control of the ISO by the Participating TO. The costs of any transmission facility turned over to the Operational Control of the ISO shall be fully included in the Participating TO's TRR. The TRR is shown in Appendix I.

3.106 Uncontrollable Force

Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant which could not be avoided through the exercise of Good Utility Practice.

3.107 [Omitted]

3.108 Utility Distribution Company ("UDC")

An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and/or that provides regulated retail electric service to End-Users.

3.109 Voltage Support

Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.

3.110 Western System Coordinating Council ("WSCC")

The Western System Coordinating Council or its successor.

3.111 Wheeling Access Charge

The charge assessed by the ISO that is paid by a Scheduling Coordinator for Wheeling in accordance with Section 26.1.4.1 of the ISO Tariff. Wheeling Access Charges shall not apply for Wheeling under a bundled non-economy Energy coordination agreement of a Participating TO executed prior to July 9, 1996. The Wheeling Access Charge consists of a High Voltage Wheeling Access Charge and, if applicable, a Low Voltage Wheeling Access Charge.

3.112 Wheeling Out

Except for Existing Rights exercised under an Existing Contract in accordance with Sections 16.1 of the ISO Tariff, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO.

3.113 Wheeling Through

Except for Existing Rights exercised under an Existing Contract in accordance with Sections 16.1 of the ISO Tariff, the use of the ISO Controlled Grid for the transmission of Energy from a resource located outside the ISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO.

3.114 Wheeling

Wheeling Out or Wheeling Through

3.115 Wholesale Customer

A person wishing to purchase Energy and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.

3.116 [Omitted]

4. Eligibility

Transmission service over a Participating TO's system shall be provided only to Eligible Customers. Any dispute as to whether an End-Use Customer is eligible for wholesale transmission service shall be resolved by FERC and any dispute as to whether an End-Use Customer is eligible for service under this TO Tariff shall be resolved by the Local Regulatory Authority.

5. Access Charges and Transmission Rates

5.1 Low Voltage Access Charge

The Low Voltage Access Charge shall be determined in accordance with the ISO Tariff. The Low Voltage Access Charge customer shall pay the Participating TO a Low Voltage Access Charge equal to the product of the Participating TO's Low Voltage Access Charge rate and the kilowatt-hours of transmission service provided under the ISO Tariff to the Low Voltage Access Charge customers. The Participating TO shall not assess the Low Voltage Access Charge to any other Participating TO for transmission service over Low Voltage Transmission Facilities that such other Participating TO receives and pays for under an Existing Contract. Where a customer receives deliveries of energy at voltage levels both above and below 200 kV, the Low Voltage Access Charge shall be applied only to kilowatt-hours of energy delivered at voltage levels lower than 200 kV. The Participating TO's monthly charge to be applied to Low Voltage Access Charge customers is set forth in Appendix II herein.

5.2 Wheeling Access Charge

The Wheeling Access Charge shall be determined in accordance with the ISO Tariff. The Wheeling Access Charge assessed by the ISO consists of a High Voltage Wheeling Access Charge and, if applicable, a Low Voltage Wheeling Access Charge. The High Voltage Wheeling Access Charge is set forth in the ISO Tariff. The Participating TOs' Low Voltage Wheeling Access Charge is set forth in Appendix II herein.

5.3 End-User Transmission Rates

End-User transmission rates for a FERC-jurisdictional Participating TO shall be based on the Base Transmission Revenue Requirement authorized by FERC. In addition, all End-Use Customers of a FERC-jurisdictional Participating TO shall be subject to the FERC-authorized TRBAA, Reliability Services Charge and TACBAA rates. The Participating TO's End-User transmission rates, by retail rate schedule, are set forth in Appendix III. An End-User shall pay the same End-User transmission rate as other similarly situated End-Use Customers of the Participating TO regardless of its Energy supplier. End-Users withdrawing power from the Participating TO's transmission or distribution facilities shall not qualify for transmission access under the Wheeling Access Charge if FERC would be prohibited from ordering transmission service for such customer by Section 212(h) of the FPA.

5.4 Transmission Revenue Requirement

As set forth in the ISO Tariff, the Transmission Revenue Requirement for each Participating TO is used to develop the Access Charges set forth in the ISO Tariff and is used by the ISO to calculate the disbursement of Wheeling revenues among Participating TOs. Wheeling revenues are disbursed by the ISO to Participating TOs pursuant to Section 26.1.4.3. of the ISO Tariff. The Transmission Revenue Requirement, High Voltage Transmission Revenue Requirement, and Low Voltage Transmission Revenue Requirement for the Participating TO are set forth in Appendix I.

5.5 Transmission Revenue Balancing Account Adjustment ("TRBAA")

The Participating TO shall maintain a Transmission Revenue Balancing Account ("TRBA") that will ensure that all Transmission Revenue Credits associated with transmission service from the ISO are flowed through to or recovered from, as appropriate, customers taking service. The TRBAA shall be equal to:

$$TRBAA = Cr + Cf + RF\&U$$

Where:

Cr = The balance of the TRBA, including interest, consisting of the principal balance as recorded in FERC Account No. 182.3 as of September 30 and the projected change for the remaining months of the year prior to commencement of the January billing cycle. The principal balance represents the balance in the TRBA from the previous period and the difference in the amount of revenues or expenditures from Transmission Revenue Credits and the amount of such revenues or expenditures that has been refunded to or collected from customers through operation of the TRBAA, plus an allocation for a three year amortization of ETC Cost Differentials. Interest shall be calculated using the interest rate pursuant to Section 35.19(a) of FERC's regulations under the Federal Power Act (18 CFR Section 35.19(a)). Interest shall be calculated based on the average TRBA principal balance each month, compounded quarterly. For purposes of calculating the TRBAA, an adjustment for recovery of any abandonment cost amounts approved by the Commission in connection with the Canada to Northern California transmission project will be reflected in the TRBA effective June 1, 2011;

Cf = The forecast of Transmission Revenue Credits for the new rate period; and

RF&U = Franchise Fees, San Francisco Gross Receipts Tax and Uncollectible Accounts.

Beginning in January of each year, the bills of End-Use Customers of the Participating TO shall include, as a component of the End-User transmission rates, a TRBAA rate per kilowatt-hour (rounded to the nearest $0.00001) equal to:

$$\text{TRBAA Rate} = \frac{\text{TRBAA}}{\text{S}}$$

Where :

S = Total Gross Load, in kilowatt-hours measured at the customer-meter level, recorded for the twelve month period ending September 30 of the year prior to commencement of the January billing cycle.

The Participating TO's TRBAA used to calculate the High Voltage Transmission Revenue Requirement shall not include amounts accrued to the Participating TO's TRBAA prior to the Transition Date as defined in Section 4 of Appendix F, Schedule 3 of the ISO Tariff, but will include other adjustments specified in Section 6, 8 and 13 of Appendix F, Schedule 3 of the ISO Tariff.

5.6 Reliability Services Balancing Account ("RSBA") Charge

The bills of End-Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers to which the Reliability Services Tariff or a reliability services-related contract amendment applies, of a Participating TO shall include a Reliability Services Charge which shall be initially calculated from a forecast of Reliability Services costs for the calendar year in which the Reliability Services Charges will be collected. Beginning in January of each year, the

Reliability Services Charge rates shall be recalculated from the balance of the RSBA and a forecast of Reliability Services costs for the following year. The Reliability Services Charge rates are shown in Appendix VI for End Use Customers. The Reliability Services Charge rate for High Voltage Wholesale customers is equal to:

$$\text{TO Tariff High Voltage Wholesale Reliability Services Rate} = \frac{RS_{Rr} + RS_{Rf} + RF\&U}{E_R}$$

Where:

RS_{Rr} = The balance of the RSBA allocated to High Voltage transmission, including interest, consisting of the principal balance recorded in FERC Account No. 182.3 as of September 30 and the projected change for the remaining months of the year prior to commencement of the January billing cycle. The principal balance represents the balance in the RSBA from the previous period for High Voltage transmission and the ISO bills to the Participating TO for Reliability Services costs for High Voltage transmission and the amount of such revenues or expenditures that has been refunded to or collected from customers for Reliability Services for High Voltage transmission through operation of the RSBA. The interest on the principal balance for the RSBA allocated to High Voltage transmission, shall be calculated using the interest rate pursuant to Section 35.19(a) of FERC's regulations under the FPA (18 CFR Section 35.19(a)). Interest shall be calculated based on the average RSBA principal balance each month, compounded quarterly;

RS_{Rf} = A forecast of reliability services costs for High Voltage transmission to be billed to the Participating TO by the ISO;

RF&U = Franchise Fees, San Francisco Gross Receipts Tax and Uncollectible Accounts; and

E_R = A forecast of the total kilowatt-hour deliveries by the Participating TO End Use Customers, TO Tariff Wholesale Customers and Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule in their Existing Contracts, whichever is applicable, over the Participating TO's High Voltage transmission facilities.

The Reliability Services Charge rate for Low Voltage Wholesale customers is equal to:

TO Tariff Low Voltage Wholesale Reliability Services Rate =

$$\text{TO Tariff High Voltage Wholesale Reliability Services Rate} + \frac{RS_{Lr} + RS_{Lf} + RF\&U}{E_L}$$

Where:

RS_{Lr} = The balance of the RSBA allocated to Low Voltage transmission, including interest, consisting of the principal balance recorded in FERC Account No. 182.3 as of September 30 and the projected change for the remaining months of the year prior to commencement of the January billing cycle. The principal balance represents the balance in the RSBA from the previous period for Low Voltage transmission and the ISO bills to the Participating TO for Reliability Services costs for Low Voltage transmission and the amount of such revenues or expenditures that has been refunded to or collected from customers for Reliability Services for Low Voltage transmission through operation of the RSBA. The interest on the principal balance for the RSBA allocated to Low Voltage Transmission, which shall be calculated using the interest rate pursuant to Section 35.19(a) of FERC's regulations under the Federal Power Act (18 CFR Section 35.19(a)). Interest shall be calculated based on the average RSBA principal balance each month, compounded quarterly;

RS_{Lf} = A forecast of reliability services costs for Low Voltage transmission to be billed to the Participating TO by the ISO;

RF&U = Franchise Fees, San Francisco Gross Receipts Tax and Uncollectible Accounts; and

E_L = A forecast of the total kilowatt-hour deliveries by the Participating TO End Use Customers, TO Tariff Wholesale Customers and Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule in their Existing Contracts, whichever is applicable, over the Participating TO's Low Voltage transmission facilities.

5.7 Transmission Access Charge Balancing Account Adjustment

The Participating TO shall maintain a Transmission Access Charge Balancing Account ("TACBA"). Each month the Participating TO shall make two entries to the TACBA. The first entry will equal the difference between (i) the actual charges by the ISO to the Participating TO pursuant to Section 26.1.2 of the ISO Tariff for the High Voltage Access Charge and Transition Charge and (ii) the revenues disbursed by the ISO to the Participating TO pursuant to Section 26.1.3 of the ISO Tariff. The second entry will equal the Transmission Access Charge Balancing Account Adjustment ("TACBAA") rate revenues billed to End-Use Customers during the month. Interest on the amounts accumulated in the TACBA shall be calculated based on the average TACBA principal balance each month, compounded quarterly, using the interest rate specified in FERC regulations, at 18 C.F.R. Section 35.19a. The bills of End-Use Customers of the Participating TO shall include, as a component of the End-User transmission rates, a TACBAA rate per kilowatt-hour (rounded to the nearest $0.00001) equal to:

$$\text{TACBAA Rate} = \frac{Br + Bf - Rf + RF\&U}{S}$$

Where:

Br = The balance of the TACBA, including interest, consisting of the recorded balance and the projected change for the remaining months of the period prior to the commencement of the billing cycle implementing a new rate;

Bf = A forecast of the annual Access Charge billings from the ISO;

Rf = A forecast of the annual Access Charge revenues disbursed by the ISO to the Participating TO pursuant to Section 26.1.3 of the ISO Tariff;

RF&U = Franchise Fees, San Francisco Gross Receipts Tax and Uncollectible Accounts; and

S = Total Gross Load, in kilowatt-hours measured at the customer-meter level, recorded for the most recent twelve-month period prior to the Participating TO's filing with FERC to revise the TACBAA rate.

The TACBAA shall be revised effective March 1 of each year; however, nothing in this TO Tariff shall limit the Participating TO from filing with the FERC under FPA Section 205 to revise the TACBAA rate at any other time.

5.8 End-Use Customer Refund Balancing Account Adjustment

The Participating TO shall maintain an End-Use Customer Refund Balancing Account ("ECRBA") for refunds due End-Use Customers for transmission service rendered on or after the effective date of new or revised retail rates authorized by the CPUC which modify the retail rates charged during the transition period established pursuant to Section 368 of the California Public Utilities Code. The Access Charge bills of End-Use Customers of the Participating TO shall include an ECRBAA for the twelve-month period beginning on the January 1 following the first date such a refund is due to End-Use Customers as ordered by the Commission. The Participating TO reserves the right to implement the ECRBAA sooner than the next January 1. When applicable, this ECRBAA will appear as a rate component of the End-Use Customer Access Charges for End-User Service in Appendix III. ECRBAA shall be a credit or charge equal to the refund or surcharge amount due to End-Use customers, including interest. The ECRBAA shall be equal to:

$$ECRBAA = Rr + Rf$$

Where:

Rr = The balance of the ECRBA, including interest, consisting of the principal balance recorded in FERC Account No. 182.3 as of September 30 and the projected change for the remaining months of the year prior to commencement of the January billing cycle. The principal balance represents the balance in the ECRBA from the previous period and the amount of such revenues or expenditures that has been refunded to or collected from customers through operation of the ECRBAA. The interest on the principal balance for the ECRBA, which shall be calculated using the interest rate pursuant to Section 35.19(a) of FERC's regulations under the Federal Power Act (18 CFR Section 35.19(a)). Interest shall be calculated based on the average ECRBA principal balance each month, compounded quarterly; and

Rf = Additional refunds, if any, due to End-Use Customers since the previous ECRBAA became effective as approved by the Commission.

6. Ancillary Services - Applicability and Charges

Ancillary Services are needed to maintain reliability within the ISO Controlled Grid. Ancillary Services may be provided to the ISO. The prices for Ancillary Services shall be determined in accordance with the ISO Tariff. Participating TO rates or bidding rules for Ancillary Services are set forth in Appendix IV of this TO Tariff.

7. Billing and Payment

7.1 End-Users

Billing and payment rules applicable to End-Users shall be pursuant to the then-current rules of the applicable Local Regulatory Authority.

7.2 Low Voltage Access Charge Revenues

7.2.1 Billing Procedure

The Participating TO shall have access to metering data and shall have reasonable physical access to customer facilities to install any recording devices or telemetering equipment it may require to obtain data needed under this TO Tariff. The UDC, MSS or Scheduling Coordinator shall grant the Participating TO such access to facilities as may be required for proper operation and maintenance of all revenue metering equipment. Within a reasonable time after the Participating TO has collected the metering data for a month in which the Low Voltage Access Charge applies, the Participating TO shall submit an invoice to the applicable UDC, MSS or Scheduling Coordinator for the Low Voltage Access Charges applicable to services furnished during that month. The invoice shall be paid by the UDC, MSS, or Scheduling Coordinator within twenty days of receipt. All payments shall be made in immediately available funds payable to the Participating TO, or by wire transfer to a bank named by the Participating TO.

7.2.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in FERC regulations at 18 C.F.R. Section 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Participating TO.

7.2.3 Default

In the event the UDC, MSS or Scheduling Coordinator fails, for any reason other than a billing dispute as described below, to make payment to the Participating TO on or before the due date as described above, and such failure of payment is not corrected within 30 calendar days after the Participating TO notifies the applicable UDC, MSS or Scheduling Coordinator to cure such failure, a default by the UDC, MSS or Scheduling Coordinator shall be deemed to exist. Upon the occurrence of a default, the Participating TO may initiate a proceeding with FERC (or the Local Regulatory Authority for a Local Publicly Owned Electric Utility) to terminate service but shall not terminate service until FERC, or the Local Regulatory Authority, as applicable, so approves any such request. In the event of a billing dispute between the Participating TO and the UDC, MSS or Scheduling Coordinator, the Participating TO will continue to provide service under this TO Tariff as long as the applicable UDC, MSS or Scheduling Coordinator: (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the UDC, MSS or Scheduling Coordinator fails to meet these two requirements for continuation of service, then the Participating TO may provide notice to the UDS, MSS or Scheduling Coordinator of its intention to suspend service in sixty days, in accordance with FERC policy.

7.3 Wheeling Revenues

The ISO, pursuant to the ISO Tariff, shall pay to Participating TOs all Wheeling revenues at the same time as other ISO charges and payments are settled. For Wheeling revenues associated with CRRs allocated to Load Serving Entities outside the ISO Balancing Authority Area, the ISO shall pay the Participating TOs any excess prepayment amounts within thirty (30) days of the end of the term of the CRR Allocation.

8. Obligation to Interconnect or Construct

8.1 Participating TO Obligation to Interconnect

The Participating TO shall, at the request of a third party pursuant to Section 10, interconnect its system to the wholesale generation or wholesale load of such third party, or modify an existing wholesale Interconnection. Interconnections under this TO Tariff shall be available to entities eligible to request Interconnection consistent with the provisions of Section 210(a) of the FPA. Interconnections requested by entities or individuals that are not so eligible shall be governed by the Local Regulatory Authority. The procedures for Interconnections of wholesale generation to the ISO Controlled Grid shall be governed by the ISO Tariff.

8.1.1 Interconnection to Transmission System

Interconnection must be consistent with Good Utility Practice, in conformance with all Applicable Reliability Criteria, all applicable statutes, regulations, and ISO reliability criteria for the ISO Controlled Grid. The Participating TO will not accommodate the Interconnection if doing so would impair system reliability, or would otherwise adversely affect the ability of the Participating TO to honor its Encumbrances existing as of the time an entity submits its Interconnection Application. The Participating TO shall identify any such adverse effect on its Encumbrances in the System Impact Study performed pursuant to Section 10.7. To the extent the Participating TO determines that the Interconnection will have an adverse effect on Encumbrances, the party requesting Interconnection shall mitigate such adverse effect.

8.1.1.1 Letter Agreement

Pursuant to Section 12 of Appendix DD of the ISO Tariff, prior to executing an Interconnection Agreement, a party seeking Interconnection may, in order to advance the implementation of its Interconnection, request, and the Participating TO shall offer the party, a Letter Agreement, a pro forma version of which is set forth in Appendix X of this TO Tariff, that authorizes the Participating TO to begin engineering, design, and procurement of long lead-time items, or construction necessary for the establishment of the Interconnection. However, Participating TO shall not be obligated to offer a Letter Agreement if the party seeking Interconnection is in Dispute Resolution as a result of an allegation that the party seeking Interconnection has failed to meet any milestones or comply with any prerequisites specified in the ISO Tariff. The Letter Agreement is an optional procedure. The Letter Agreement shall provide for the party seeking Interconnection to pay the cost of all activities authorized by the party and to make advance payments or provide other satisfactory security for such costs.

Following a party seeking Interconnection's request for a Letter Agreement, the Participating TO shall prepare and tender to the party seeking Interconnection a draft Letter Agreement in the form of the Participating TO's FERC-approved Letter Agreement as set forth in Appendix X of this TO Tariff, including draft exhibits that include the proposed scope of work, estimated costs, payments, financial security and milestones, as applicable. The party seeking Interconnection shall provide written comments, or notification of no comments, to the draft exhibits within thirty (30) Calendar Days. The Participating TO and the party seeking Interconnection shall negotiate concerning any disputed provisions of the exhibits to the draft Letter Agreement for not more than ninety (90) Calendar Days after the Participating TO tenders the draft Letter Agreement to the party seeking Interconnection. If the party seeking Interconnection determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft Letter Agreement and request submission of the unexecuted Letter Agreement with FERC or initiate dispute resolution procedures pursuant to Section 14 of this TO Tariff. If the party seeking Interconnection requests termination of the negotiations, but within ninety (90) Calendar Days after the Participating TO tenders the draft Letter Agreement to the party seeking Interconnection, fails to request either the filing of the unexecuted Letter Agreement or initiate dispute resolution procedures, it shall be deemed to have withdrawn its request for a Letter Agreement and the Participating TO shall have no further obligation to enter into a Letter Agreement, unless an extension is mutually agreed to by the parties. The Participating TO shall provide to the party seeking Interconnection a final Letter Agreement within fifteen (15) Business Days after the completion of the negotiation process.

Following submission of the final Letter Agreement to the party seeking Interconnection, the party shall either: (i) execute two originals of the tendered Letter Agreement and return them to the Participating TO; or (ii) request in writing that the Participating TO file with FERC a Letter Agreement in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the two executed originals of the tendered Letter Agreement (if it does not conform with a FERC-approved Letter Agreement) or the request to file an unexecuted Letter Agreement, the Participating TO shall file the Letter Agreement with FERC, together with its explanation of any matters as to which the party seeking Interconnection and the Participating TO disagree and support for the costs that the Participating TO proposes to charge to the party seeking Interconnection under the Letter Agreement. An unexecuted Letter Agreement should contain terms and conditions deemed appropriate by the Participating TO for the Interconnection request.

If the party seeking Interconnection executes the final Letter Agreement, the Participating TO and the party seeking Interconnection shall perform their respective obligations in accordance with the terms of the Letter Agreement, subject to modification by FERC. Upon submission of an unexecuted Letter Agreement, the party seeking Interconnection and the Participating TO shall promptly comply with the unexecuted Letter Agreement, subject to modification by FERC.

8.1.2 Costs Associated with Interconnection

Each party requesting Interconnection shall pay the costs of planning installing, owning, operating, and maintaining any Direct Assignment Facilities and , if applicable, any Reliability Upgrades required to provide the requested Interconnection. In addition, such party shall implement all existing operating procedures necessary to safely and reliably interconnect such party’s generation or wholesale load to the facilities of the Participating TO and to ensure the

ISO Controlled Grid's conformance with the ISO Grid Planning Criteria, and shall bear all costs of implementing such operating procedures. Any additional costs associated with accommodating the Interconnection shall be allocated in accordance with the cost responsibility methodology set forth in the ISO Tariff for transmission expansions or upgrades.

8.1.3 Interconnection Agreement

Pursuant to Section 10.4, 10.7.1, or 10.9.1, a party requesting Interconnection shall request in writing that the Participating TO tender to such party an Interconnection Agreement that will be filed with FERC, or the Local Regulatory Authority, in the case of a Local Publicly Owned Electric Utility. The Interconnection Agreement will include, without limitation, cost responsibilities and payment provisions for any engineering, equipment, construction, ownership, operation and maintenance costs for any Direct Assignment Facilities, any Reliability Upgrades, and for any other mitigation measures. For an Interconnection request to remain a Completed Interconnection Application, the party requesting the Interconnection shall execute the Interconnection Agreement and return it to the Participating TO within thirty (30) Business Days of receipt. Alternatively, if an Eligible Customer requesting the Interconnection requests the Participating TO to file an unexecuted Interconnection Agreement and commits to abide by the terms, conditions, and cost assignments determined to be just and reasonable under the ISO ADR Procedures, including any determination by FERC or on appeal of a FERC determination in accordance with that process, the Participating TO shall promptly file an unexecuted Interconnection Agreement. Provided, however, that if the ISO ADR Procedures concerns whether the requesting entity is an Eligible Customer, the Participating TO shall not be obligated to file an unexecuted Interconnection Agreement or commence construction of the Interconnection facilities or incur other costs under the Interconnection Agreement until a final order determining the just and reasonable rates, terms, and conditions for such Interconnection Agreement has been issued by the applicable court or regulatory authority. The Interconnection Agreement will set forth a payment schedule that enables the Participating TO to recover its costs. If the applicant elects not to execute the Interconnection Agreement and does not request the Participating TO to file an unexecuted Interconnection Agreement, its Completed Interconnection Application shall be deemed withdrawn, and the applicant shall reimburse to the

Participating TO all costs reasonably incurred in processing the application not covered by any System Impact Study Agreement or Facilities Study Agreement.

8.1.4 Due Diligence to Construct

The Participating TO shall use due diligence to construct, within a reasonable time, any Direct Assignment Facilities and any Reliability Upgrades that it is obligated to construct pursuant to this TO Tariff. The Participating TO's obligation to build will be subject to: 1) its ability, after making a good faith effort, to obtain any necessary approvals and property rights under applicable federal, state, and local laws; 2) the presence of a cost recovery mechanism with cost responsibility assigned in accordance with the ISO Tariff or applicable FERC precedent; and 3) a signed Interconnection Agreement or a signed Expedited Interconnection Agreement or, by mutual agreement of the parties, FERC acceptance for filing of an unexecuted Interconnection Agreement.

8.1.5 Energization

The Participating TO shall not be obligated to energize, nor shall wholesale load be entitled to have its interconnection to the ISO Controlled Grid energized, unless and until an Interconnection Agreement has been executed, or filed at FERC pursuant to Section 8.1.3, and becomes effective and such wholesale load has demonstrated to the ISO's reasonable satisfaction that it has complied with all of the requirements of the ISO Tariff and the requirements of this TO Tariff.

8.1.6 Coordination with ISO on Interconnection Requests

The Participating TO shall coordinate with the ISO, pursuant to the provisions of the TCA, in developing Interconnection standards and guidelines for processing Interconnection requests under this TO Tariff.

8.2 Obligation to Construct Expansions or Facility Upgrades

The Participating TO shall be obligated to: (1) perform System Impact or Facility Studies where the Project Sponsor or the ISO agrees to pay the study cost and specifies the project objectives to be achieved, and (2) build transmission additions and facility upgrades where the Participating TO is obligated to construct or expand facilities in accordance with and subject to the limitations Section 24 of the ISO Tariff and this TO Tariff.

8.2.1 Obligation to Construct

A Participating TO shall not be obligated to construct or expand transmission facilities or system upgrades unless and until the conditions stated in Section 9.2.1 hereof have been satisfied.

8.2.2 Local Furnishing Participating TO Obligation to Construct

A Local Furnishing Participating TO shall not be obligated to construct or expand transmission facilities or system upgrades unless and until the conditions stated in Section 9.3.3 hereof have been satisfied.

8.3 Request for FERC Deference Regarding Need Determination

It is intended that FERC grant substantial deference to the factual determinations of the ISO, (including the ISO's ADR Procedures), the CPUC, WSCC, or RTG coordinated planning processes as to the need for or construction of a facility, the need for full cost recovery, and the allocation of costs.

9. Expansion Process

9.1 Determination of Facilities

A Participating TO shall perform a Facilities Study in accordance with this Section where (1) the Participating TO is obligated to construct or expand facilities in accordance with Section 24 of the ISO Tariff and this TO Tariff; (2) a Market Participant agrees to pay the costs of the Facilities Study and specifies the project objectives to be achieved in terms of increased capacity or reduced congestion; or (3) the Participating TO is required to perform a Facilities Study pursuant to the ISO Tariff.

9.1.1 Payment of Facilities Study's Cost

9.1.1.1 Market Participant to Pay for Facilities Study

Where a Market Participant requests a Facilities Study and the need for the transmission addition or upgrade has not yet been established in accordance with the procedures established herein and the ISO Tariff, the Market Participant shall pay the cost of the Facilities Study.

9.1.1.2 Project Sponsor or Proponent to Pay for Facilities Study

Where the facilities to be added or upgraded have been determined to be needed in accordance with the procedures established herein and the ISO Tariff, the Project Sponsor, Project Proponent, or the ISO requesting the study shall pay the reasonable cost of the Facilities Study. When the Participating TO is the Project Sponsor in accordance with the ISO Tariff, the costs of the Facilities Study shall be recovered through its Access Charges and transmission rates.

9.1.1.3 Principal Beneficiaries to Pay for Facilities Study

Where the facilities to be added or upgraded have been determined to be needed and the principal beneficiaries have been identified by the ISO or ISO ADR Procedures in accordance with the ISO Tariff, the Project Sponsor and the identified principal beneficiaries shall pay the reasonable cost of the Facilities Study, in such proportions as may be agreed, or, failing agreement, as determined in accordance with the ISO ADR Procedures.

9.1.2 Payment Procedure

Where a Facilities Study is being conducted pursuant to this TO Tariff, the Participating TO shall, as soon as practicable, tender to the Market Participant, Project Sponsor, Project Proponent, ISO, or identified principal beneficiaries, as the case may be, a Facilities Study Agreement that defines the scope, content, assumptions, and terms of reference for such study, the estimated time required to complete it, and such other provisions as the parties may reasonably require and pursuant to which such Market Participant, Project Sponsor, Project Proponent, the ISO, or identified principal beneficiaries agree to reimburse the Participating TO the reasonable cost of performing the required Facilities Study. If the Market Participant, Project Sponsor, Project Proponent, the ISO, or identified principal beneficiaries, as the case may be, agree to the terms of the Facilities Study Agreement, they shall execute the Facilities Study Agreement and return it to the Participating TO within ten Business Days. If such Market Participant, Project Sponsor, Project Proponent, the ISO, or identified principal beneficiary elects not to execute a Facilities Study Agreement, the Participating TO shall have no obligation to complete a Facilities Study.

9.1.3 Facilities Study Procedures

Upon receipt of an executed Facilities Study Agreement, a copy of which has been provided to the ISO by the party requesting the Facilities Study, the Participating TO will use due diligence to complete the required Facilities Study in accordance with the terms of the Facilities Study Agreement.

9.2 Obligation to Build

9.2.1 Due Diligence to Construct

Subject to Section 9.3.3 of this TO Tariff, the Participating TO shall use due diligence to construct, within a reasonable time, additions or upgrades to its transmission system that it is obligated to construct pursuant to the ISO Tariff and this TO Tariff. The Participating TO's obligation to build will be subject to: 1) its ability, after making a good faith effort, to obtain the necessary approvals and property rights under applicable federal, state, and local laws; 2) the presence of a cost recovery mechanism with cost responsibility assigned in accordance with the ISO Tariff; and 3) a signed Participation Agreement. The Participating TO will not construct or expand its existing or planned transmission system, if doing so would impair system reliability as determined through systems analysis based on the Applicable Reliability Criteria.

9.2.2 Delay in Construction or Expansion

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Participating TO shall promptly notify: (1) the Project Sponsor with regard to facilities determined to be needed; (2) the Parties to the Participation Agreement with regard to facilities determined to be needed pursuant to the ISO Tariff where principal beneficiaries were identified; and (3) the ISO. In such circumstances, the Participating TO shall, within thirty days of notifying such Project Sponsor, Parties to the Participation Agreement, and the ISO of such delays, convene a technical meeting with such Project Sponsor, Parties to the Participation Agreement, and the ISO to discuss the circumstances which have arisen and evaluate any options available. The Participating TO also shall make available to such Project Sponsor, Parties to the Participation Agreement, and the ISO, as the case may be, studies and work papers related to the cause and extent of the delay and the Participating TO's ability to complete the new facilities, including all information that is in the possession of the Participating TO that is reasonably needed to evaluate the alternatives.

9.2.2.1 Alternatives to the Original Facility Additions

If the review process of Section 9.2.2 determines that one or more alternatives exist to the originally planned construction project, the Participating TO shall present such alternatives for consideration to the Project Sponsor, Parties to the Participation Agreement, and the ISO, as the case may be. If upon review of any alternatives, such Project Sponsor, the ISO, or Parties to the Participation Agreement wish to evaluate or to proceed with one of the alternative additions or upgrades, such Project Sponsor, the ISO, or Parties to the Participation Agreement may request that the Participating TO prepare a revised Facility Study pursuant to Sections 9.1.1, 9.1.2, and 9.1.3 of this TO Tariff. In the event the Participating TO concludes that no reasonable alternative exists to the originally planned addition or upgrade and the Project Sponsor or Parties to the Participation Agreement or the ISO disagree, the dispute shall be resolved pursuant to the ISO ADR Procedure.

9.2.2.2 Refund Obligation for Unfinished Facility Additions

If the Participating TO and the Project Sponsor, the ISO, or Parties to the Participation Agreement, as the case may be, mutually agree that no other reasonable alternatives exist, the obligation to construct the requested additions or upgrades shall terminate and any deposit not yet applied toward the expended project costs shall be returned with interest pursuant to FERC Regulation 35.19(a)(2)(iii). However, the Project Sponsor and any identified principal beneficiaries, as the case may be, shall be responsible for all costs prudently incurred by the Participating TO through the time the construction was suspended.

9.3 Transmission Construction On the Systems of Other TOs

9.3.1 Responsibility for Third Party Additions

A Participating TO shall not be responsible for making arrangements for any engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Participating TO will undertake reasonable efforts through the coordinated planning process to assist in making such arrangements, including, without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

9.3.2 Coordination of Third-Party System Additions

Where transmission additions or upgrades being built pursuant to the ISO Tariff require additions or upgrades on other systems, to the extent consistent with Section 9.3.3 of this TO Tariff, the Participating TO shall coordinate construction on its own system with the construction required by others. The Participating TO, after consultation with the ISO, the Project Sponsor, and Parties to the Participation Agreement, as the case may be, may defer construction if the new transmission facilities on another system cannot be completed in a timely manner. The Participating TO shall notify such Project Sponsor, Parties to the Participation Agreement, and the ISO, in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of the new facilities. Within forty Business Days of receiving written notification by the Participating TO of its intent to defer construction pursuant to this section, such Project Sponsor, Parties to the Participation Agreement, or the ISO may challenge the decision in accordance with the ISO ADR Procedure.

9.3.3 Expansion by "Local Furnishing Participating TOs"

Notwithstanding any other provision of this TO Tariff, prior to requesting that a Local Furnishing Participating TO construct or expand facilities, the ISO or Project Sponsor shall tender (or cause to be tendered) an application under Section 211 of the FPA requesting FERC to issue an order directing the Local Furnishing Participating TO to construct or expand facilities as necessary to provide transmission service as determined pursuant to the ISO Tariff. Such Local Furnishing Participating TO shall thereafter, within ten Business Days of receiving a copy of the Section 211 application, waive its right to a request for service under Section 213(a) of the FPA and to the issuance of a proposed order under Section 212(c) of the FPA. Upon receipt of a final order from FERC under Section 211 of the FPA that is no longer subject to rehearing or appeal, such Local Furnishing Participating TO shall construct or expand facilities to comply with that FERC order and shall transfer to the ISO Operational Control over the Local Furnishing Participating TO's expanded transmission facilities in accordance with the ISO Tariff.

10. Interconnection Process

10.1 Applicability

All requests for Interconnection of wholesale load directly to the ISO Controlled Grid from parties eligible to request such Interconnection consistent with Section 210(a) of the FPA shall be processed pursuant to the provisions of this Section 10. All requests for Interconnection of wholesale generation directly to the ISO Grid shall be processed pursuant to the provisions of the ISO Tariff.

10.2 Applications

A party requesting Interconnection shall submit a written Interconnection Application which provides the information required in Section 10.3 to the Participating TO and shall send a copy of the application to the ISO. The Participating TO shall time-stamp the application to establish study priority.

10.3 Interconnection Application

An Interconnection Application shall provide all of the information listed in 18 CFR § 2.20, including, but not limited to, the following:

(i) The identity, address, telephone number, and facsimile number of the party requesting interconnection;

(ii) The Interconnection point(s) to the ISO Controlled Grid contemplated by the applicant;

(iii) The resultant (or new) maximum amount of Interconnection capacity;

(iv) The proposed date for i energizing the Interconnection and the term of the Interconnection service;

(v) Such other information as the Participating TO reasonably requires to process the application.

In addition to the information specified above, the following information may also be provided in order to properly evaluate system conditions:

(vi) The electrical location of the source of the power (if known) to be transmitted pursuant to the applicant's request for Interconnection. If the source of the power is not known, a system purchase will be assumed.

Within ten (10) Business Days after receipt of an Interconnection Application, the Participating TO shall determine, whether the application is complete ("Completed Interconnection Application"). Wherever possible, the Participating TO will attempt to remedy deficiencies in the Interconnection Application through informal communications with the applicant. If such efforts are unsuccessful, the Participating TO shall return the Interconnection Application to the applicant.

The Participating TO will treat the information provided in the Interconnection Application, including the applicant's identity, as confidential at the request of the applicant except to the extent that disclosure of this information is required by this TO Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG or ISO transmission information sharing agreements. The Participating TO shall treat this information consistent with the standards of conduct contained in Part 37 of FERC's regulations.

10.4 Review of Completed of Interconnection Application

After receiving a Completed Interconnection Application, the Participating TO, will determine on a non-discriminatory basis whether a System Impact Study is required. Whenever the Participating TO, determines that a System Impact Study is not required and that neither Reliability Upgrades nor changes in existing operating procedures are required, the Participating TO shall notify the applicant within fifteen (15) Business Days of the Completed Application Date. If the Interconnection can be accommodated without any Direct Assignment Facilities, then within thirty (30) Business Days of such notice from the Participating TO, the applicant shall request the Participating TO to tender to the applicant an Interconnection Agreement within thirty (30) Business Days of such request. The Participating TO shall tender to the applicant an Interconnection Agreement as provided in Section 8.1.3. If the Participating TO determines, upon the review of the Completed Interconnection Application, that Direct Assignment Facilities are required, the Participating TO shall tender to the applicant a Facilities Study Agreement within twenty (20) Business Days of the Completed Application Date and continue the interconnection process pursuant to Section 10.8.

10.5 Notice of Need for System Impact Study

If the Participating TO, determines that a System Impact Study is necessary to accommodate the requested Interconnection, the Participating TO shall so inform the applicant, as soon as practicable. In such cases, the Participating TO shall within twenty (20) Business Days of receipt of a Completed Interconnection Application, tender a System Impact Study Agreement that defines the scope, content, assumptions and terms of reference for such study to be completed by the Participating TO, the estimated time required to complete it, and such other provisions as the parties may reasonably require, and pursuant to which the applicant shall agree to reimburse the Participating TO for the reasonable actual costs of performing the required System Impact Study. A description of the Participating TO’s transmission assessment practices for completing a System Impact Study is provided in the Participating TO’s FERC Form 715. For an Interconnection request to remain a Completed Interconnection Application, the applicant shall execute the System Impact Study Agreement and return it to the Participating TO within ten (10) Business Days together with payment for the reasonable estimated cost of performing the System Impact Study. Alternatively, if the applicant requests the Participating TO to proceed with the System Impact Study and commits to abide by the terms, conditions, and cost assignments ultimately determined under the ISO ADR Procedures, including any determination by FERC or appeal of a FERC determination in accordance with that process, the Participating TO shall promptly proceed with the System Impact Study provided that such request is accompanied by payment for the reasonable estimated cost of the System Impact Study, and the parties shall submit the disputed terms for resolution under the ISO's ADR Procedures. If the applicant elects not to execute a System Impact Study Agreement, and does not request that the Participating TO proceed with the System Impact Study, its application shall be deemed withdrawn, and the applicant shall reimburse to the Participating TO all costs reasonably incurred in processing the application.

10.6 System Impact Study Cost Reimbursement

10.6.1 Cost Reimbursement

The System Impact Study Agreement shall clearly specify the charge, based on the Participating TO's estimate of the cost and time for completion of the System Impact Study. The charge shall not exceed the reasonable actual cost of the study. In performing the System Impact Study, the Participating TO shall rely, to the extent reasonably practicable, on existing transmission planning studies. The applicant will not be assessed a charge for such existing studies; however, the applicant will be responsible for the reasonable charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the applicant's request.

10.6.2 Multiple Parties

If multiple parties request Interconnection at the same location, the Participating TO may conduct a single System Impact Study. The costs of that study shall be pro-rated among the parties requesting Interconnection.

10.7 System Impact Study Procedures

Upon receipt of an executed System Impact Study Agreement or initiation of the ISO ADR Procedures and receipt of payment for estimated study costs, the Participating TO will use due diligence to complete the required System Impact Study within a sixty (60) calendar day period. The System Impact Study will identify whether any transmission additions or upgrades are necessary to serve a wholesale load. The System Impact Study will also identify any adverse impact on Encumbrances existing as of the applicants Completed Application Date. In the event that the Participating TO is unable to complete the required System Impact Study within such time period, it shall so notify the applicant, in writing, and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the applicant and the ISO. The Participating TO will use the same due diligence in completing the System Impact Study for others as it uses when completing studies for its affiliated UDC load. The Participating TO shall notify the applicant and the ISO immediately upon completion of the System Impact Study.

10.7.1 Procedures Upon Completion of System Impact Study

Within fifteen (15) Business Days of completion of the System Impact Study, the Participating TO shall notify the applicant whether the transmission system will be adequate to accommodate all of a request for Interconnection. If no costs are likely to be incurred for any Direct Assignment Facilities, any Reliability Upgrades, or implementing any operating procedures, then within thirty (30) Business Days of receipt of the completed System Impact Study, the applicant shall request the Participating TO to tender an Interconnection Agreement within thirty (30) Business Days of such request. The Participating TO shall tender to the applicant an Interconnection Agreement as provided in Section 8.1.3. If costs are likely to be incurred to accommodate a request for Interconnection, the Participating TO shall tender to the applicant a Facilities Study Agreement pursuant to Section 10.8.

10.8 Notice of Need for Facilities Study

If a System Impact Study indicates that additions or upgrades to the ISO Controlled Grid are needed to satisfy an applicant's request for Interconnection, the Participating TO shall, within fifteen (15) Business Days of the completion date of the System Impact Study tender to the applicant a Facilities Study Agreement that defines the scope, content, assumptions and terms of reference for such study; the estimated time required to complete the required study; and such other provisions as the parties may reasonably require, and pursuant to which the applicant agrees to reimburse the Participating TO for the reasonable actual costs of performing the required Facilities Study. For an Interconnection request to remain a Completed Interconnection Application, the applicant shall execute the Facilities Study Agreement and return it to the Participating TO within ten (10) Business Days together with payment for the reasonable estimated costs of performing the Facilities Study. Alternatively, if the applicant requests the Participating TO to proceed with the Facilities Study and commits to abide by the terms, conditions, and cost assignments ultimately determined under the ISO ADR Procedures, including any determination by FERC or appeal of a FERC determination in accordance with that process, the Participating TO shall promptly proceed with the Facilities Study provided that such request is accompanied by payment for the reasonable estimated cost of the Facilities Study, and the parties shall submit the disputed terms for resolution under the ISO ADR Procedures. If the applicant elects not to execute a Facilities Study Agreement and does not request that the Participating TO proceed with the Facilities Study, its application shall be deemed withdrawn and the applicant shall reimburse to the Participating TO all costs reasonably incurred in processing the application not covered by the System Impact Study Agreement.

10.9 Facilities Study Procedures

Upon receipt of an executed Facilities Study Agreement or initiation of the ISO ADR Procedures and receipt of payment for the estimated study costs, the Participating TO will use due diligence to complete the required Facilities Study within a sixty (60) calendar day period. In the event that the Participating TO is unable to complete the required Facilities Study within such time period, it shall so notify the applicant, in writing, and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed Facilities Study shall be made available to the applicant.

10.9.1 Execution of Interconnection Agreement

Within thirty (30) Business Days of receipt of the completed Facilities Study, the applicant shall request the Participating TO to tender an Interconnection Agreement within thirty (30) Business Days of such request. The Participating TO shall tender to the applicant an Interconnection Agreement as provided in Section 8.1.3.

10.10 Partial Interim Service

If the Participating TO determines that there will not be adequate transmission capability to satisfy the full amount requested in a Completed Interconnection Application, the Participating TO nonetheless shall be obligated to offer and provide the portion of the requested Interconnection that can be accommodated without any additional Direct Assignment Facilities or Reliability Upgrades. However, the Participating TO shall not be obligated to provide the incremental amount of requested Interconnection that requires such additional facilities or upgrades until such facilities or upgrades have been placed in service.

10.11 Expedited Interconnection Procedures

In lieu of the procedures set forth above, the applicant shall have the option to expedite the processing of its Completed Interconnection Application. In order to exercise this option, the applicant shall submit in writing a Request for Expedited Interconnection Procedures to the Participating TO, within ten (10) Business Days after receiving a copy of the System Impact Study for the proposed Interconnection. Within ten (10) Business Days after receiving a Request for Expedited Procedures, the Participating TO shall tender an Expedited Interconnection Agreement that requires the applicant to compensate the Participating TO for all costs reasonably incurred pursuant to the terms of this TO Tariff for processing the Completed Interconnection Application and providing the requested Interconnection. While the Participating TO agrees to provide the applicant with its best estimate of the costs of any needed Direct Assignment Facilities and, if applicable, Reliability Upgrades, and other charges that may be incurred, unless otherwise agreed by the parties, such estimate shall not be binding and the applicant must agree in writing to compensate the Participating TO for all actual Interconnection costs reasonably incurred pursuant to the provisions of this TO Tariff. The applicant shall execute and return such Expedited Interconnection Agreement within ten (10) Business Days of its receipt or the applicant's request for Interconnection will cease to be a Completed Interconnection Application and will be deemed terminated and withdrawn. In that event, the applicant shall reimburse the Participating TO for all costs reasonably incurred in processing the application not covered by the terms of the System Impact Study Agreement.

11. Uncontrollable Forces and Indemnification

11.1 Procedures To Follow if Uncontrollable Force Occurs

In the event of the occurrence of an Uncontrollable Force which prevents a Party from performing any of its obligations under this TO Tariff, such Party shall (i) immediately notify the other Parties in writing of the occurrence of such Uncontrollable Force, (ii) not be entitled to suspend performance in any greater scope or longer duration than is required by the Uncontrollable Force, (iii) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance hereunder, (iv) keep the other Parties apprised of such efforts on a continual basis and (v) provide written notice of the resumption of performance hereunder. Notwithstanding any of the foregoing, the settlement of any strike, lockout, or labor dispute constituting an Uncontrollable Force shall be within the sole discretion of the Party to this TO Tariff involved in such strike, lockout, or labor dispute and the requirement that a Party must use its best efforts to remedy the cause of the Uncontrollable Force and mitigate its effects and resume full performance hereunder shall not apply to strikes, lockouts, or labor disputes. No Party will be considered in default as to any obligation under this TO Tariff if prevented from fulfilling the obligation due to the occurrence of an Uncontrollable Force.

11.2 Indemnification

A Market Participant, to the extent permitted by law, shall at all times indemnify, defend, and save the Participating TO harmless from any and all damages, losses, claims, (including claims and actions relating to injury or to death of any person or damage to property), demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Participating TO's performance of its obligations under this TO Tariff on behalf of a Market Participant, except in cases of negligence or intentional wrongdoing by the Participating TO.

12. Regulatory Filings

Nothing contained herein shall be construed as affecting, in any way, the right of any FERC jurisdictional Participating TO furnishing services in accordance with this TO Tariff, or any tariff and rate schedule which results from or incorporates this TO Tariff, unilaterally to make application to FERC as it deems necessary and appropriate to recover its Transmission Revenue Requirements, or for a change in its rates, including changes in rate methodology, or for a change in designation of transmission facilities to be placed under the ISO's control, in each case under Section 205 of the FPA and pursuant to the FERC's Rules and Regulations promulgated thereunder.

12.1 Open Access

For purposes of the Stranded Cost Recovery available under Order Nos. 888 and 888-A, this Tariff, combined with the ISO Tariff and wholesale distribution access tariff, if any, shall be considered an open access tariff under FERC Order Nos. 888 and 888-A.

12.2 Stranded Cost Recovery

If a retail customer becomes a legitimate wholesale transmission customer of a public utility or transmitting utility, e.g., through municipalization, and costs are stranded as a result of the retail turned wholesale customer's access to wholesale transmission under this TO Tariff, the utility may seek recovery of such costs through rates for wholesale transmission services to that customer, as provided in FERC Order Nos. 888 and 888-A, provided that nothing in this Section 12.2 shall be deemed in derogation of stranded cost recovery rights under state law.

13. Creditworthiness

13.1 UDCs, MSSs and Scheduling Coordinators Using Low Voltage

For the purpose of determining the ability of a UDC, MSS or Scheduling Coordinator to meet its obligations related to service hereunder using the Participating TO's Low Voltage Transmission Facilities, the Participating TO may require reasonable credit review procedures for the UDC, MSS or Scheduling Coordinator. This review shall be made in accordance with standard commercial practices. In addition, the Participating TO may require the UDC, MSS or Scheduling Coordinator to provide and maintain in effect during the term of the service, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under this TO Tariff, or an alternative form of security proposed by the UDC, MSS or Scheduling Coordinator and acceptable to the Participating TO, and consistent with commercial practices established by the Uniform Commercial Code, that protect the Participating TO against the risk of non-payment.

13.2 End-Users

Creditworthiness rules applicable to End-Users shall be pursuant to the then-current rules of the applicable Local Regulatory Authority.

14. Disputes

Except as limited below or as otherwise limited by law, the ISO ADR Procedures shall apply to all disputes between parties which arise under this TO Tariff or under or in respect of the proposed terms and conditions of a Facilities Study Agreement, System Impact Study Agreement or Expedited Service Agreement. The ISO ADR Procedures set forth in Section 13 of the ISO Tariff shall not apply to disputes as to whether rates and charges set forth in this TO Tariff (other than charges for studies) are just and reasonable under Sections 205 and 206 of the FPA.

15. Recovery of Reliability Services Costs

All Reliability Services Costs payable by a Participating TO shall be recovered from End-Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule in their Existing Contracts, whichever is applicable, withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system. Reliability services billed to the Participating TO by the ISO include costs which are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area pursuant to the ISO Tariff and are defined as "Reliability Services Costs" in the Master Definitions Supplement, Appendix A to the currently effective ISO Tariff.

16. Miscellaneous

16.1 Notices

Any notice, demand, or request in accordance with this TO Tariff, unless otherwise provided in this TO Tariff, shall be in writing and shall be deemed properly served, given, or made: (i) upon delivery if delivered in person, (ii) five days after deposit in the mail if sent by first class United States mail, postage prepaid, (iii) upon receipt of confirmation by return electronic facsimile if sent by facsimile, or (iv) upon delivery if delivered by prepaid commercial courier service, in each case addressed to a Party at the address set forth in Appendix V. Any Party may at any time, by notice to the other Parties, change the designation or address of the person specified in Appendix V to receive notice on its behalf. Any notice of a routine character in connection with service under this TO Tariff or in connection with operation of facilities shall be given in such a manner as the Parties may determine from time to time, unless otherwise provided in this TO Tariff.

16.2 Waiver

Any waiver at any time by any Party of its rights with respect to any default under this TO Tariff, or with respect to any other matter arising in connection with this TO Tariff, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this TO Tariff. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

16.3 Confidentiality

16.3.1 Maintaining Confidentiality If Not for Public Disclosure

The Participating TO shall maintain the confidentiality of all of the documents, data, and information provided to it by any other Party that such Party may designate as confidential, provided, however, that the information will not be held confidential by the receiving Party if (1) the designating Party is required to provide such information for public disclosure pursuant to this TO Tariff or applicable regulatory requirements, or (2) the information becomes available to the public on a non-confidential basis (other than from the receiving Party).

16.3.2 Disclosure of Confidential Information

Notwithstanding anything in this Section 16.3.2 to the contrary, if any Party is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 16.3.2, the Party may disclose such information; provided, however, that as soon as such Party learns of the disclosure requirement and prior to making such disclosure, such Party shall notify the affected Party or Parties of the requirement and the terms thereof. The affected Party or Parties may, at their sole discretion and own costs, direct any challenge to or defense against the disclosure requirement and the disclosing Party shall cooperate with such affected Party or Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The disclosing Party shall cooperate with the affected Parties to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

16.4 TO Tariff Supersedes Existing Tariffs

This TO Tariff, together with the ISO Tariff and wholesale distribution access tariff, if any, supersedes any pre-existing open access transmission tariff of the Participating TO.

16.5 Titles

The captions and headings in this TO Tariff are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the rates, terms, and conditions of this TO Tariff.

16.6 Severability

If any term, covenant, or condition of this TO Tariff or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest, by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this TO Tariff and their application shall not be affected thereby but shall remain in force and effect. The Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination, unless a court or governmental agency of competent jurisdiction holds that such provisions are not severable from all other provisions of this TO Tariff.

16.7 Preservation of Obligations

Upon termination of this TO Tariff, all unsatisfied obligations of each Party shall be preserved until satisfied.

16.8 Governing Law

This TO Tariff shall be interpreted, governed by, and construed under the laws of the State of California, without regard to the principles of conflict of laws thereof, or the laws of the United States, as applicable, as if executed and to be performed wholly within the State of California.

16.9 Appendices Incorporated

The several appendices to this TO Tariff, as may be revised from time to time, are attached to this TO Tariff and are incorporated by reference as if fully set forth herein.

APPENDIX I:
TRANSMISSION AND RELIABILITY SERVICES
REVENUE REQUIREMENTS

Total revenue requirement associated with transmission facilities and entitlements turned over to the operational control of the ISO by the Participating TO, which reflects a reduction or increase for Transmission Revenue Credits.

1. The Transmission Revenue Requirement for purposes of calculating End-User transmission rates shall be equal to the sum of the Base Transmission Revenue Requirement calculated pursuant to the Formula Rate, Appendix VIII and the TRBAA of ($478,011,578) .

2. For purposes of the ISO's calculation of Access Charges under Section 26.1 of the ISO Tariff:

    a. The High Voltage Transmission Revenue Requirement shall be equal to the sum of a High Voltage Base Transmission Revenue Requirement and a Standby Transmission Demand Revenue credit both calculated pursuant to the Formula Rate, Appendix VIII, and a High Voltage TRBAA of ($286,211,944) .

    b. The Low Voltage Transmission Revenue Requirement shall be equal to the sum of a Low Voltage Base Transmission Revenue Requirement and a Standby Transmission Demand Revenue credit both calculated pursuant to the Formula Rate, Appendix VIII, and a Low Voltage TRBAA of ($131,125,662) .

    c. The forecast of Gross Load at the High Voltage/Low Voltage interface is calculated pursuant to the Formula Rate, Appendix VIII.

3. The Reliability Services Balancing Account shall be equal to $6,860,080, which includes the forecast of Reliability Services payments PG&E will make to the ISO during 2023 of $17,283,634, plus an adjustment of ($10,423,554). This amount shall be effective until amended by PG&E in accordance with Appendix V to this Tariff.

The Reliability Service Balancing Account shall be allocated to End-Use Customers as follows:

	Retail Total
2024 RMR Costs	$17,283,634
Adjustment	($10,423,554)
2024 Revenue Requirement	$6,860,080

The End-Use Customer Refund Balancing Account Adjustment shall be allocated to End-Use Customers and include a Revenue Requirement of ($953,478) .

APPENDIX II:

ACCESS CHARGES FOR WHOLESALE TRANSMISSION

High Voltage Access Charge		See ISO Tariff
Low Voltage Access Charge**	=	Low Voltage TRR / Gross Load
High Voltage Utility-Specific Access Charge**	=	High Voltage TRR / Gross Load

** These rates are calculated pursuant to the Formula Rate, Appendix VIII and posted on www.pge.com.

<u>High Voltage Wheeling Access Charge</u>

High Voltage Wheeling Access Charge	See ISO Tariff

<u>Low Voltage Wheeling Access Charge</u>

High Voltage Wheeling Access Charge	See ISO Tariff
Low Voltage Wheeling Access Charge	See ISO Tariff

APPENDIX III:
ACCESS CHARGES FOR END-USE SERVICE

Base transmission rates for service to End-Use Customers are calculated pursuant to the Formula Rate, Appendix VIII. PG&E will post the base transmission rates applicable to each End-Use rate schedule on its website: www.pge.com.

The ECRBAA Rates for each End-Use Customer Schedule are as follows:

SCHEDULES	ECRBAA RATES
RESIDENTIAL E-1 E-6 E-TOU E-TOU-C EV EV2 EM EM TOU ES ESR ET **Energy Charge ($/kWh)**	($0.00000)
COMMERCIAL and INDUSTRIAL A-1 B-1 A-6 B-6 A-15 TC-1 **Energy Charge ($/kWh)**	($0.00000)
COMMERCIAL and INDUSTRIAL A-10 B-10 E-19 B-19 **Energy Charge ($/kWh)**	($0.00000)
COMMERCIAL and INDUSTRIAL E-20 B-20	($0.00000)

SCHEDULES	ECRBAA RATES
Energy Charge ($/kWh)	
COMMERCIAL and INDUSTRIAL S SB **Energy Charge ($/kWh)**	($0.00000)
COMMERCIAL ELECTRIC VEHICLE E-CEV-S E-CEV-L **Energy Charge ($/kWh)**	($0.00000)
AGRICULTURAL AG-1 AG-R AG-V AG-4 AG-5 AG AG-F **Energy Charge ($/kWh)**	($0.00000)
STREETLIGHTING LS-1 LS-2 LS-3 OL-1 **Energy Charge ($/kWh)**	($0.00000)

In addition, the following transmission rates shall apply to service provided to all End-Use Customers:

TRBAA Rate of ($0.00634) per kWh;

TACBAA Rate of $0.00618 per kWh.

The applicability of these rates is described in the California Public Utilities Commission jurisdictional retail tariffs.

APPENDIX IV:
RATES FOR CERTAIN ANCILLARY SERVICES
AND REPLACEMENT RESERVE

1. Availability: Pacific Gas and Electric Company makes Regulation, Spinning Reserve, on-Spinning Reserve, and Replacement Reserve available at wholesale under this Rate Schedule to the ISO and to others that are self-providing ancillary services to the ISO.

2. Applicability: This Rate Schedule applies to all such wholesale sales of Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve by Pacific Gas and Electric Company that are not otherwise subject to a particular rate schedule or contract to the ISO.

3. Rates: Sales made under this Rate Schedule shall be at rates established between PIC15c Gas and Electric Company and the purchaser of Regulation, Spinning Reserve, Non-Spinning Reserve, and/or Replacement Reserve.

4. Other Terms and Conditions: All other terms and conditions of sale shall be established by agreement between Pacific Gas and Electric Company and the purchaser of Regulation, Spinning Reserve, Non-Spinning Reserve, and/or Replacement Reserve.

5. Prohibited Affiliate Transactions: Sales of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve will not be made pursuant to this rate schedule to PG&E Corporation or any other marketer affiliated with PG&E.

6. Effective Date: This Rate Schedule shall be effective for service rendered on and after November 3, 1998.

Filed in compliance with an Order of the Federal Energy Regulatory Commission issued on the 28th day of October, 1998 in Docket No. ER98-2843-001, et al.

The rates filed under this Appendix for Voltage Support Service in Schedule 4 are cost-based and applicable when PG&E generation resources (other than must-run resources) bid to supply this service to the ISO under the terms of the ISO Tariff. PG&E may bid to supply this

Voltage Support Service subject to the availability of its resources under the applicable terms and conditions of the ISO Tariff. PG&E may submit discounted ancillary service bids on a nondiscriminatory basis. Ancillary Service and Replacement Reserve Service Schedules are listed below.

Spinning Reserve Service:	Schedule 1.
Non-Spinning Reserve Service:	Schedule 2.
Replacement Reserve Service:	Schedule 3.
Voltage Support Service:	Schedule 4.
Regulation Service:	Schedule 5.

SCHEDULE 1

Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by PG&E generating units (other than must run units) that are on-line and loaded at less than maximum output.

The charge for this service will be determined under the ISO Tariff.

SCHEDULE 2

Non-Spinning Reserve Service

Non-Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Non-Spinning Reserve Service may be provided by generating units that are off-line and can be synchronized to the grid and loaded with in 10 minutes with the capability to sustain that load for 2 hours.

The charge for this service will be determined under the ISO Tariff.

SCHEDULE 3

Replacement Reserve Service

Replacement Reserves are those reserves that the ISO may need when system conditions require the ISO to use both Spinning and Non-Spinning Reserves to maintain system stability and reliability.

The charge for this service will be determined under the ISO Tariff.

SCHEDULE 4

Voltage Support Service

In order to maintain transmission voltages on the ISO Controlled Grid within acceptable limits, generation facilities within the ISO Controlled Grid may be operated to produce (or absorb) reactive power.

Voltage Support Service may be provided directly from PG&E generation resources (other than must run units). Cost-based rates for Voltage Support Service are set forth below.

Yearly Service Rate:	$1.52/kW-year
Monthly Service Rate:	$0.1267/kW-month
Weekly Service Rate:	$0.0292/kW-week
Daily Service Rate:	$0.0042/kW-day
Hourly Service Rate:	$0.00017/kW-hour

The charge for this service will be determined under the ISO Tariff.

SCHEDULE 5

Regulation Service

Regulation Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load.

The charge for this service will be determined under the ISO Tariff.

APPENDIX V:
BALANCING ACCOUNT FOR
RELIABILITY SERVICES CHARGES RECOVERY

1. **Applicability**. This balancing account is applicable to End Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule, whichever is applicable, withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system.

2. **Description**. Reliability Services that the ISO may bill to the Participating TO include 1) RMR services provided pursuant to ISO Tariff Section 5.2; and 2) Outof-Market services provided pursuant to ISO Tariff Section 11.2.4.2.1.

3. **Reliability Services Revenue Requirement**. For purposes of this Appendix V, the term "High Voltage" shall also mean "Regional" and the term "Low Voltage" shall also mean "Local" as it applies to Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule, whichever is applicable. The initial reliability services revenue requirement as allocated between High Voltage and Low Voltage Transmission Facilities, which is effective beginning on the Effective Date of this rate schedule, shall be established through a filing by the Participating TO with the FERC under Section 205 of the Federal Power Act. The initial reliability services revenue requirement shall be equal to the forecasted reliability services payments the Participating TO will make to the ISO during the twelve month period following the Effective Date. The Participating TO's initial reliability services revenue requirement is shown on Appendix I.

   Subsequent to the establishment of the initial High Voltage and Low Voltage reliability services revenue requirements, the High Voltage and Low Voltage reliability services revenue requirements and associated High Voltage and Low Voltage Reliability Services Charges shall be revised annually to be effective on January 1 of each year. To implement this annual revision, the Participating TO shall file with the FERC for a revision to the High Voltage and Low Voltage reliability services revenue requirements and Regional and Local Reliability Services Charges by January 31 of the calendar year in which the charges are to be effective, requesting as necessary, waiver of all prior notice requirements. In the annual revision, the High Voltage and Low Voltage reliability services revenue requirements shall be established based on the forecast High Voltage and Low Voltage reliability services payments the Participating TO will make to the ISO for the calendar year, plus the recorded balance in the Reliability Services Balancing Account (RSBA) as of November 30 of the year prior to commencement of the following calendar year.

The first step in calculating the updated Reliability Service Charge rates shall be a calculation of the Reliability Service Charges that would have been allocated to End Use Customers, TO Tariff Wholesale Customers, and Existing Contract customers who take service under the Reliability Services Tariff or a Reliability Services Rate Schedule in their Existing Contracts, whichever is applicable, had actual reliability services costs and actual usage data been used in the reliability services costs allocation. The same formulas used to allocate High Voltage and Low Voltage reliability service costs, and End Use Customer, TO Tariff Wholesale Customer and Existing Contract customer reliability services costs will be repeated using actual data instead of forecasted data. The difference between what was actually collected and what should have been allocated is determined and carried forward in the reliability services cost allocation made in the subsequent year.

The RSBA is a mechanism that is designed to ensure that the Participating TO neither underrecovers nor overrecovers from customers the reliability services costs it is assessed by the ISO. The balance in the account represents the cumulative difference between the revenues billed by the Participating TO under Reliability Charges to Market Participants withdrawing Energy from the ISO Controlled Grid on the Participating TO's transmission system and the Reliability Services Costs paid by the Participating TO to the ISO, plus interest. Interest shall be calculated using the interest rate pursuant to Section 35.19a of the FERC's regulations under the Federal Power Act (18 CFR Section 35.19a). Interest shall be calculated based on the average RSBA balance each month, compounded quarterly.

4. **Reliability Charges**. Charges for recovery of the High Voltage and Low Voltage reliability services revenue requirements are provided in Appendix II for Wholesale Transmission Customers and Appendix VI for End Use Customers.

5. **Effective Date**. This rate schedule is effectively for service rendered on and after the date designated by the Commission.

APPENDIX VI:

RELIABILITY SERVICE CHARGES FOR END-USE SERVICE

TABLE OF CONTENTS

The applicability of these rates is described in the California Public Utilities Commission jurisdictional retail tariffs.

RESIDENTIAL SCHEDULES

SCHEDULE E-1

SCHEDULES E-6

SCHEDULE E-TOU

SCHEDULE E-TOU-C

SCHEDULE EV

SCHEDULE EV2

SCHEDULE EM

SCHEDULE EM TOU

SCHEDULE ES

SCHEDULE ESR

SCHEDULE ET

Energy Charge ($/kWh)	$0.00012

COMMERCIAL & INDUSTRIAL SCHEDULES

SCHEDULE A-1 AND B-1

SCHEDULE A-6 AND B-6

SCHEDULE A-15

SCHEDULE TC-1

Energy Charge ($/kWh)	$0.00008

SCHEDULE A-10 AND B-10

BASIS FOR DEMAND CHARGE: The customer will be billed for demand according to the customer's "maximum demand" each month. The number of kW used will be recorded over 15-minute intervals; the highest 15-minute average in the month will be the customer's maximum demand. SPECIAL CASES: (1) If the customer's use of energy is intermittent or subject to severe fluctuations, a 5-minute interval may be used, and (2) If the customer uses welders, the demand charge will be subject to the minimum demand charges for those welders' ratings, as explained in Section J of PG&E's CPUC Rule 2.

Maximum Demand Charge ($/kW/mo)	$0.02

SCHEDULE E-19 AND B-19

BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals.

Maximum Demand Charge ($/kW/mo)	$0.02

SCHEDULE E-20 AND B-20

BASIS FOR DEMAND CHARGE: Demand will be averaged over 15-minute intervals. "Maximum demand" will be the highest of all the 15-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to severe fluctuations, a 5-minute interval may be used. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of PG&E's CPUC Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 15-minute intervals.

Maximum Demand Charge ($/kW/mo)	$0.03

SCHEDULE S AND SB

RESERVATION CAPACITY: The Reservation Capacity to be used for billing under the above rates shall be as set forth in the customer's contract for service. For new or revised contracts, the Reservation Capacity shall be determined by the customer. However, if the customer's standby demand exceeds this new contracted capacity in any billing month, that standby demand shall become the new Reservation or Contract Capacity for 12 months, beginning with that month. See Special Condition 7 for the definition of Reservation Capacity for Supplemental Standby Service customers.

The Reservation Charge, in dollars per kilowatt (kW), applies to 85 percent of the customer's Reservation Capacity, as defined in Special Condition 1 of the tariffs.

Reservation Charge ($/kW/mo)	$0.00
Energy Charge ($/kWh)	$0.00004

COMMERCIAL ELECTRIC VEHICLE SCHEDULES

Electric Rate Schedule A-6 is used to set the reliability service charge rate component of the Commercial Electric Vehicle rate schedules.

SCHEDULE E-CEV-S

SCHEDULE E-CEV-L

Energy Charge ($/kWh)	$0.00008

AGRICULTURAL SCHEDULES

The CPUC-jurisdictional retail tariffs should be referred to for detailed descriptions of how agricultural demand charges are assessed.

SCHEDULE AG-1

SCHEDULE AG-R

SCHEDULE AG-V

SCHEDULE AG-4

SCHEDULE AG-5

SCHEDULE AG

SCHEDULE AG-F

Energy Charge ($/kWh)	$0.00008

STREETLIGHTING SCHEDULES

SCHEDULE LS-1

SCHEDULE LS-2

SCHEDULE LS-3

SCHEDULE OL-1

Energy Charge ($/kWh)	$0.00007

APPENDIX VII:
NOTICES

Pursuant to Section 16.1, notices, demands or requests to PG&E in accordance with this TO Tariff shall be sent in writing to:

Pacific Gas and Electric Company

Electric Transmission Rates Mail Code B13L

P.O. Box 770000

San Francisco, California 94177

Attention: Manager, Electric Transmission Rates

APPENDIX VIII:
FORMULA RATE

The Protocols set forth in Attachment 1 of this Appendix and the Model set forth in Attachment 2 of this Appendix together comprise the "Formula Rate."

APPENDIX VIII: FORMULA RATE

ATTACHMENT 1: PROTOCOLS

TABLE OF CONTENTS

PROTOCOLS

1. INTRODUCTION

These Protocols describe: (1) the terms and operation of the Formula Rate to calculate the Base Transmission Revenue Requirement (“Base TRR”) and Access Charges and Transmission Rates; (2) PG&E’s commitment to use the Formula Rate to annually update the Base TRR and Access Charges and Transmission Rates; and (3) the terms under which certain Formula Rate provisions may be revised, subject to FERC approval.

The Model and its underlying Schedules are presented as Attachment 2 to Appendix VIII. All references in the Protocols to Schedules refer to Schedules in the Model. The Schedules contain fixed formulas that will be populated with data from PG&E’s most recent annual FERC Form 1 filing or from other PG&E records when appropriate. The sources of the data used in the Formula Rate will be identified in the Model by references to their corresponding location in FERC Form 1 or source from PG&E records.

All capitalized terms used in these Protocols shall have the meanings as set forth herein, elsewhere in the TO Tariff, or in the Model.

2. DEFINED TERMS

2.1 Abandoned or Cancelled Projects

An abandoned or cancelled project is one that will not be completed and not result in assets being placed into service.

2.2 Access Charges and Transmission Rates

The charges and rates described in Section 5 of the TO Tariff.

2.3 Annual True-up Adjustment or ATA

The Annual True-up Adjustment (“ATA”) is a component of the Wholesale Base TRR and is calculated for each Annual Update as described in these Protocols.

2.4 Base Transmission Revenue Requirement

The Transmission Revenue Requirement which does not reflect amounts for the Transmission Revenue Balancing Account Adjustment, Standby Transmission Demand Revenues, or the Reliability Services Balancing Account.

2.5 Draft Annual Update

The draft of the proposed update of the Base TRR and Access Charges and Transmission Rates, for the upcoming Rate Year.

2.6 Errors

A mistake or omission regarding the Formula Rate, such as FERC Form 1 and SEC financial reporting errors, transposition mistakes, arithmetic and other inadvertent computational errors, erroneous Form 1 references, and mechanical errors in application of the Formula Rate such as the formula in an Excel cell containing logic or syntax errors or referencing an incorrect cell. Errors do not include matters involving the exercise of judgment.

2.7 Filing Year

The Filing Year is the calendar year in which an Annual Update is filed.

2.8 Final True-Up Adjustment

The Final True-up Adjustment is the adjustment made for the period spanning the day after the period covered by the most recent ATA that was included in the Base TRR to the expiration of the Formula Rate, as described in these Protocols.

2.9 Formula Rate

The Protocols and the Model in this Appendix VIII.

2.10 Incremental Transmission Revenue Requirement or ITRR

The Incremental Transmission Revenue Requirement ("ITRR") is a component of the Wholesale Base TRR that PG&E anticipates during the Rate Year.

2.11 Initial Technical Conference

The one-day meeting convened by PG&E during the time period specified in Section 4.1 to discuss the Draft Annual Update posted on June 15.

2.12 Interested Party(ies)

Parties interested in the information exchange and review described in these Protocols including, but not exclusive to, customers under the TO Tariff, California state regulatory commissions, consumer advocacy agencies, and the California state attorney general.

2.13 Model

The Model, set forth in Attachment 2 to this Appendix VIII, is the Excel® based spreadsheet containing Schedules (worksheets) that operate as the mechanism for calculating the Base TRR and Access Charges and Transmission Rates.

2.14 Notification List

Parties receiving the Draft Annual Update, as defined in Section 4.2.

2.15 Prior Year

The Prior Year is the calendar year immediately preceding the Filing Year.

2.16 Prior Year TRR

The Prior Year TRR is a component of the Base TRR and represents PG&E's cost of service using Prior Year recorded end of year Rate Base values and is based on cost inputs from PG&E's FERC Form 1 or PG&E records as expressly provided in the Model.

2.17 Privileged Materials

Privileged Materials shall have the meaning identified in Section 3(b)(1) of the Non-Disclosure Agreement that is identified as Exhibit A to the Protocols.

2.18 Protocols

The Protocols set forth in Attachment 1 to this Appendix VIII.

2.19 Rate Base

Rate Base is the value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The components of PG&E's Rate Base are listed in Schedule 1-BaseTRR of the Model.

2.20 Rate Year

Rate Year means the year in which the rates will be effective and is the calendar year immediately following the Filing Year.

2.21 Retail Tax Adjustment

The Retail Tax Adjustment is a component of the Base TRR and is the tax adjustment made in compliance with the methodology prescribed in FERC Order No. 144 for the normalization of certain tax items. The calculation of this adjustment is found in Schedule 23-RetailSGTax of the Model.

2.22 Retail Uncollectible Expense

Retail Uncollectible Expense is a component of the Base TRR and is the adjustment permitted by current retail ratemaking practices adopted by the CPUC as determined by applying a fixed adjustment factor to every dollar of revenue to be collected from retail customers. The calculation of this adjustment is found in Schedule 1-BaseTRR of the Model

2.23 Schedules

The Schedules are individual worksheets in the Model that reflect the components and formulas used to calculate the Base TRR and Access Charges and Transmission Rates.

2.24 Supplemental Technical Conference

The meeting convened by PG&E during the time period specified in Section 4.1 to discuss revisions to the Draft Annual Update identified since its initial posting on June 15.

2.25 True-up TRR

The True-up TRR is a component of the ATA and is calculated in Schedule 3-True-upTRR. The True-up TRR represents the actual amount of costs that PG&E incurred in the Prior Year.

2.26 Wholesale Base TRR

The Wholesale Base TRR is a component of the Base TRR and is calculated in Schedule 1-BaseTRR of the Model.

3. TERM OF THE FORMULA RATE

The Formula Rate shall become effective January 1, 2024, or such other date authorized by FERC. Beginning on that date, PG&E's Base TRR and Access Charges and Transmission Rates shall be subject to true-up and revision in accordance with these Protocols. The Formula Rate shall remain effective until: (1) PG&E files a revised Formula Rate or other rate methodology (*e.g.*, stated rates) to replace the Formula Rate under FPA Section 205 and PG&E's filing is accepted by FERC; (2) an entity(ies) and/or individual(s) file for revisions of the Formula Rate under FPA Section 206 and FERC directs revisions to the Formula Rate as a result of the FPA Section 206 filing; or (3) FERC directs PG&E to revise the Formula Rate.

4. UPDATING THE BASE TRR

4.1 Draft Annual Update Schedule

As set forth below, the procedures for updating the Base TRR and Access Charges and Transmission Rates for the upcoming Rate Year shall be followed while this Formula Rate is in effect. The following is a summary of the events and associated dates for PG&E's performance of these procedures. If any of the dates listed below do not fall on a business day, the due date for the event shall be the following business day.

Event	**Date**
Posting Date of Draft Annual Update	June 15
First Day to Submit Information Requests	June 15
Initial Technical Conference on Draft Annual Update	Between July 7 and 23
Additional Technical Conference(s) and Weekly Calls, as described in Sections 4.4.2 and 4.4.4	August 1 – November 1
Provide a Revised Draft Annual Update with a summary of the changes	November 1
Supplemental Technical Conference on revised Draft Annual Update	Between November 4 and 7
Last Day to Submit Information Requests	December 1*
Annual Update Filed at FERC	December 1
Rates Effective Date	January 1
Last Day for Formal Comments or Protests to Annual Update	January 30
Last Day for PG&E to Submit Answer to Formal Comments or Protests	March 15

* Note: See Section 4.5.2 regarding response timing for information requests received after November 8.

4.2 Draft Annual Update Posting and Notice

In accordance with the schedule set forth in Section 4.1 above, PG&E shall post to its website, pge.com, its Draft Annual Update and will provide electronic notice of such posting to: (1) the CPUC; (2) any person or entity admitted as a party in the FERC proceeding concerning PG&E's Transmission Owner 21 ("TO21") Formula Rate filing; (3) any person or entity admitted as a party in any subsequent Annual Update proceeding filed by PG&E in accordance with these Protocols; and (4) any other Interested Party that requests to be added (collectively, "Notification List"). PG&E shall send via email a PDF version of its FERC Form 1 to the Notification List no later than ten (10) days after submitting its FERC Form 1 to FERC.

4.3 Draft Annual Update Contents and Additional Information

4.3.1 The Draft Annual Update shall set forth the Base TRR and Access Charges and Transmission Rates for the upcoming Rate Year and shall include populated versions of all Schedules in their native format with all formulas and links intact and all workpapers used in the calculation of the Base TRR, in their native format, with all formulas and links intact. Specifically, the Draft Annual Update shall:

(1) Identify all methodological changes to inputs;

(2) Identify any changes to the sources of information from FERC Form 1 or where/how information was obtained from PG&E's records from the description in the Model;

(3) Include all workpapers from which a Formula Rate input is taken, in native format, and with all data used;

(4) Include a workable, data-populated Model in native format with all formulas and links intact;

(5) Provide for the applicable Rate Year the following information related to affiliate cost allocations: (1) a detailed description of the methodologies

used to allocate and directly assign costs between PG&E and its affiliates by service category or function, including any changes to such cost allocation methodologies from the Prior Year and the reasons for those changes; and (2) the magnitude of such costs that have been allocated or directly assigned between PG&E and each affiliate by service category or function;

(6) Identify any change in accounting relative to the Prior Year that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate including: (1) the initial implementation date of a new or revised accounting standard or policy; (2) the initial implementation date of new or revised accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction; (3) correction of Errors and prior period adjustments, including prior period accounting adjustments to correct Errors that impact the inputs to the Formula Rate in the Rate Year; (4) the implementation of new estimation methods or policies that change prior estimates; (5) changes to income tax elections and accounting entries as a result of an amended income tax return; and (6) changes to FERC Form 1 reporting practices for financial or operational data that impact the inputs to the Formula Rate. To the extent these accounting changes affect PG&E's inputs to its Formula Rate, PG&E shall provide a narrative explanation of the individual impact of those items on charges billed under the Formula Rate;

(7) Identify all reorganization, merger, or sale of transmission asset transactions during the previous year;

(8) Identify any known Errors or adjustments in FERC Form 1 data used in the Model; and

(9) Identify items included in the Formula Rate at an amount other than on a historical cost basis (e.g., fair value adjustments).

4.3.2 Within fifteen (15) business days of the posting of the Draft Annual Update, PG&E will e-mail to the Notification List the following:

(1) A report identifying any FERC Account reported on Schedules 18-OandM and 19-AandG that experiences an increase or decrease of $10 million or more over the same value reported in the previous Annual Update; and

(2) A narrative discussion of the reasons for any increase or decrease identified in Section 4.3.2(1) and an explanation as to how the increase or decrease impacts the inputs to Schedules 18 and 19.

4.4 Draft Annual Update Technical Conferences and Weekly Information Request Calls

4.4.1 PG&E will provide notice to the Notification List of a one-day Initial Technical Conference to discuss the Draft Annual Update at least fifteen (15) business days prior to the Initial Technical Conference. If Interested Parties provide a list of topics they would like to address at least seven (7) business days before the Initial Technical Conference, PG&E shall make best efforts to address these topics at the Initial Technical Conference.

4.4.2 After the Initial Technical Conference, an Interested Party may request additional technical conferences to address specific questions. In the request, the Interested Party shall provide a list of the specific questions that it would like to address. Upon such request, PG&E and the Interested Party shall make best efforts to schedule a technical conference as soon as possible, but no later than ten (10) calendar days after the request has been made. PG&E will provide notice to the Notification List of any additional technical conference(s) and the questions to be covered at least five (5) calendar days prior to the additional technical conference(s).

4.4.3 PG&E will provide notice to the Notification List of a Supplemental Technical Conference to discuss revisions to the Draft Annual Update at least five (5) calendar days prior to the Supplemental Technical Conference. At the Supplemental Technical Conference, PG&E will explain revisions to the Draft Annual Update.

4.4.4 PG&E shall host a weekly call to discuss the Draft Annual Update and information requests. If Interested Parties identify via an e-mail to PG&E at least three (3) business days in advance of the weekly call any questions related to the Draft Annual Update or information requests that they would like to discuss, PG&E shall make best efforts to address these topics on the weekly call. PG&E will provide notice to the Notification List of the weekly call and will identify the requests received by Interested Parties since the last weekly call. If no questions are identified for a specific weekly call, PG&E may cancel that weekly call.

4.4.5. All technical conferences convened pursuant to Sections 4.4.1 through 4.4.3 and any weekly calls convened pursuant to Section 4.4.4 shall occur during the time periods specified for such conferences and calls in Section 4.1. Technical conferences and weekly calls may take place in-person, via telephone, video or web-based conference. Remote access will be made available to each technical conference and weekly call. PG&E shall make appropriate personnel available for each technical conference and weekly call.

4.4.6 If, during a technical conference convened pursuant to Sections 4.4.1 through 4.4.3 or during a weekly call convened pursuant to Section 4.4.4, an Interested Party requests a written response of PG&E to memorialize the discussion or to obtain additional information, PG&E shall make a good faith effort to respond in writing within ten (10) business days without the need for the Interested Party to submit an information request pursuant to Section 4.5 below.

4.5 Information Requests

4.5.1 Interested Parties may submit reasonable information requests to PG&E regarding the Draft Annual Update within the time period specified in Section 4.1. Information requests may also include requests for further information regarding:

(1) PG&E's accounting practices, to the extent accounting impacts items included in the determination of the Base TRR and Access Charges and Transmission Rates; (2) procurement methods and cost control methodologies used by PG&E; and (3) possible Errors in prior Annual Updates (whether Errors are identified by PG&E or Interested Parties).

4.5.2 PG&E shall make a good faith effort to respond to information requests in writing within ten (10) business days of receipt, except that, for any information requests submitted to PG&E after November 8, no response will be due until January 3. PG&E shall contemporaneously provide copies of all responses to the Notification List, unless an Interested Party has affirmatively indicated to PG&E that they do not wish to receive such copies. If PG&E, in good faith, finds that an information request is unreasonable, it may object to the request. If PG&E objects to an information request, it will make a good faith effort to provide its objections within ten (10) business days of receipt of the information requests to the party serving the request. PG&E will include in its objection the basis for the objection. PG&E and the Interested Party serving the information request on PG&E will work cooperatively and in good faith to resolve any questions, objections, or disputes relating to the information requests.

4.5.3 Responses to information requests shall not be designated as settlement communications or produced under FERC's rules and regulations governing settlements, unless provided as a privileged settlement communication in a FERC proceeding being conducted under FERC's settlement rules. PG&E may mark materials provided in response to an information request as Privileged Materials in accordance with Exhibit A to the Protocols. To the extent an information request response calls for the production of Privileged Materials, PG&E will only provide such materials to the Interested Parties with whom it has entered into a non-disclosure agreement that is included as Exhibit A.

4.5.4 To the extent PG&E and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Protocols, PG&E or any Interested Party may petition FERC to appoint an Administrative Law Judge as a Discovery Master. Neither PG&E nor any Interested Party shall object to a request for a Discovery Master. The Discovery Master shall have the power to issue orders to resolve discovery disputes, as appropriate, in accordance with these Protocols and consistent with the FERC's discovery rules. The Discovery Master's orders shall be subject to appeal to FERC and to the courts to the same extent and under the same rules as would be applicable to an Initial Decision issued under Rule 708 of FERC's Rules of Practice and Procedure. In the event FERC establishes hearing procedures for an Annual Update, the Discovery Master's responsibilities shall be transferred to the Presiding Judge for such hearing effective upon his or her appointment.

4.5.5 Information request responses will be posted on PG&E's website unless a response includes Privileged Materials.

4.6 Revisions to Draft Annual Update

PG&E shall provide to the Notification List a marked version indicating any revisions to the Draft Annual Update and provide an explanation of the reason for the revisions by no later than the date specified in Section 4.1.

4.7 Annual Update

4.7.1 On or before December 1 of each year, PG&E shall file with FERC its Annual Update as an informational filing setting forth the Base TRR and Access Charges and Transmission Rates for the upcoming Rate Year. The Base TRR and Access Charges and Transmission Rates shall be effective January 1 of the upcoming Rate Year. Each Annual Update shall be filed in a new docket at FERC and shall identify the docket numbers of all prior Annual Updates submitted under this Formula Rate. PG&E shall provide notice of the Annual Update filing to the Notification List the day of the filing and shall provide the new docket number to the Notification List no later than five (5) calendar days after the filing. The

Annual Update shall include PG&E's most current, internally approved gross load forecast, which is typically approved annually in mid-October.

4.7.2 In addition to populated Schedules, the Annual Update shall include: (1) a discussion of the extent of any accounting changes that affect Formula Rate inputs; (2) a detailed description of the methodologies used to allocate and directly assign costs between PG&E and its affiliates by service category or function, including any changes to such cost allocation methodologies from the Prior Year and the reasons for those changes; and (3) the magnitude of such costs that have been allocated or directly assigned between PG&E and each affiliate by service category or function.

4.7.3 The Annual Update shall not modify the Formula Rate or subject the Formula Rate to modification and shall not constitute a rate change filing under Section 205 of the FPA.

4.7.4 No later than the date established in Section 4.1, any person may comment on or protest the Annual Update and may request that FERC establish hearing and/or settlement procedures regarding the Annual Update. PG&E and Interested Parties reserve their rights to oppose such requests on their merits. Comments or protests to the Annual Update are filed pursuant to these Protocols rather than FPA Section 206. Any comments or protests should be filed in the new docket described in Section 4.7.1. Any person may challenge the justness and reasonableness of PG&E's implementation of the Formula Rate with respect to such matters as:

(1) whether the costs and expenditures included for recovery have been or will be prudently incurred, consistent with FERC precedent regarding prudence;

(2) whether PG&E has properly and reasonably applied the Formula Rate, the Model and these Protocols;

(3) whether the costs to be recovered through the Base TRR and Wholesale Base TRR have been accurately stated, properly recorded and accounted for pursuant to applicable FERC accounting rules, and are consistent with the Formula Rate;

(4) whether PG&E's calculation methodologies are consistent with the Formula Rate;

(5) whether any accounting changes are reasonable and consistent with applicable FERC accounting rules; and

(6) whether forecasts and projections have been reasonably made.

4.7.5 PG&E shall make any revisions to the Base TRR and Access Charges and Transmission Rates required by a final FERC order with respect to each Annual Update. Unless otherwise ordered by FERC, such revisions shall be effective as of the first day of the applicable Rate Year and shall be reflected, with interest calculated pursuant to FERC's regulations, in the next Annual Update as a component of the ATA or, if applicable, the Final True-up Adjustment.

4.7.6 If PG&E determines that a previously-filed Annual Update contained Errors that affected the True-up TRR calculated in that Annual Update, including but not limited to filed corrections to its FERC Form 1 that affect the inputs to the Formula Rate or Errors in other input data used in determining the True-up TRR, then PG&E shall:

(1) recalculate the True-up TRR for all affected Prior Years;

(2) compare the difference between the initial incorrect True-up TRR and the revised correct True-up TRR; and

(3) calculate the cumulative amount of the difference, including interest calculated pursuant to FERC's regulations.

Absent a FERC order requiring refunds outside of the true-up process, the difference calculated above shall be included as an additional component to PG&E's ATA in the subsequent Annual Update as a one-time True-up Adjustment in accordance with the Formula Rate.

4.7.7 To the extent any person challenges an Annual Update under Section 4.7.4, consistent with applicable FERC precedent, PG&E will bear the burden of demonstrating the correctness of its Annual Update, including but not limited to its Annual True-up Adjustment. In this regard, PG&E will bear the burden of proving whether it has correctly implemented the Formula Rate, including the correctness of inputs to the Formula Rate. More specifically, PG&E will bear the burden of demonstrating: (1) the correctness-of its Annual Update; (2) the justness and reasonableness of the implementation of its Formula Rate; and (3) that any accounting practice or procedure is consistent with applicable law, FERC precedent, and/or FERC accounting rules.

Nothing herein is intended to alter the burden of proof applied by the Commission with respect to prudence. For the avoidance of doubt, to the extent a person's challenge to an Annual Update creates serious doubt as to the prudence of an expenditure, PG&E will bear the burden of dispelling such doubts and proving the questioned expenditure to have been prudent.

Any person challenging the Formula Rate itself will bear the burden of proof under Section 206 of the FPA.

4.7.8 It is expressly intended by these Protocols that FERC will issue an order taking action, assuming any action is requested and FERC determines that such action is appropriate, on the Annual Update if protests and/or comments on the Annual Update are filed.

4.7.9 Protests to or comments on the Annual Update under this Section 4.7 are limited to challenges for the Rate Year covered by the Annual Update as well as Errors in prior Annual Updates. Persons filing comments or protests cannot raise an issue regarding prior Annual Updates or other time periods other than the Rate Year, except with respect to Errors in prior Annual Updates.

4.7.10 PG&E may file an answer to any protests or comments to an Annual Update in the time period specified in Section 4.1.

5. ANNUAL TRUE-UP ADJUSTMENT

The ATA component of the Wholesale Base TRR ensures that PG&E shall recover its actual costs of owning and operating its transmission facilities under the ISO's control, as prescribed by the True-up TRR, defined below. As described below and shown in Schedule 4-ATA of the Model, the ATA is calculated for each Annual Update for the Prior Year if the Formula Rate was in effect during all or part of that year.

5.1 True-up TRR

5.1.1 PG&E will calculate its actual costs during the Prior Year, as measured by the True-up TRR. The True-up TRR includes the same cost of service items and is calculated in the same manner as the Prior Year TRR, with the following exceptions:

(1) Whereas end of year values were used for certain Rate Base items in the Prior Year TRR, average values are used for those same Rate Base items when calculating the True-up TRR.

(2) If the Return on Equity ("ROE") is updated midway through the Prior Year, the True-up TRR will use a weighted average ROE to compute the Cost of Capital Rate based on the number of days each ROE was in effect in the Prior Year.

(3) The Prior Year TRR includes a Depreciation Expense Rate Adjustment to account for a difference in Depreciation Expense that will occur if there is a difference between as-authorized Depreciation Rates and as-filed

Depreciation Rates. The True-up TRR is based solely on as-authorized Depreciation Rates, therefore no such Adjustment is needed.

(4) The True-up TRR includes the ATA that was included in the Prior Year rates. The addition of the ATA that was included in the Prior Year rates will ensure that previous ATAs are refunded to or collected from transmission customers.

(5) The True-up TRR will be calculated using State and Federal Tax Rates in effect during the Rate Year. If the State or Federal income tax rates change during the Rate Year, the True-Up TRR will use a weighted average tax rate based on the number of days each tax rate was in effect in the Rate Year.

5.1.2 The True-up TRR calculation is shown in Schedule 3-True-upTRR of the Model.

5.2 True-up TRR Comparison to Actual Revenues

5.2.1 PG&E will attribute the True-up TRR to each month based on a volumetric sales-based allocator using the actual monthly volumetric sales for that month divided by total annual volumetric sales from the year in which the revenues are received. For purposes of determining volumetric sales, PG&E will use ISO monthly settlements of PG&E's Gross Load.

5.2.2 PG&E will determine its actual End-User base transmission revenues collected under the Formula Rate on a monthly basis for each month of the Prior Year.

5.2.3 For each month, PG&E will calculate the difference between its monthly True-up TRR and its monthly actual End-User base transmission revenues.

5.2.4 PG&E will calculate the cumulative monthly difference through the end of the Prior Year. The difference is the Cumulative Excess or Shortfall in revenue.

5.3 Interest on Cumulative Excess or Shortfall

5.3.1 On a monthly basis, PG&E will calculate interest on the monthly Excess or Shortfall from the start of the Prior Year through the end of the Filing Year, using monthly FERC interest rates and will then add these monthly interest amounts to calculate the accumulated interest on the Cumulative Excess or Shortfall.

5.3.2 PG&E will add the accumulated interest to the Cumulative Excess or Shortfall to calculate the Total Cumulative Excess Revenue or Shortfall with Interest from the start of the Prior Year through the end of the Filing Year.

5.4 Partial Year True-up Adjustment

A Partial Year True-up Adjustment occurs when the Formula Rate was not in effect for the entire Prior Year and will account only for the months that the Formula Rate was in effect for that Prior Year. A Partial Year True-Up Adjustment will be calculated as follows:

5.4.1 PG&E will calculate the True-up TRR as described in Section 5.1.

5.4.2 PG&E will attribute the True-up TRR to each month of the Prior Year that the Formula Rate was in effect based on a volumetric sales-based allocator using the actual monthly volumetric sales for that month divided by total annual volumetric sales from the Prior Year. For purposes of determining volumetric sales, PG&E will use ISO monthly settlements of PG&E's Gross Load.

5.4.3 PG&E will allocate a portion of the True-up TRR to the months of the Prior Year that the Formula Rate was in effect in the partial year using the monthly amounts developed in Section 5.4.2.

5.4.4 PG&E will determine the Actual Revenue collected for each month of the Prior Year the Model was in effect.

5.4.5 Using the difference between each of the monthly amounts determined in Sections 5.4.3 and 5.4.4, PG&E will calculate its monthly over- or under-recovery for the partial year.

6. FINAL TRUE-UP ADJUSTMENT

6.1.1 On termination of the Formula Rate, PG&E shall calculate a Final True-up Adjustment for the period spanning the day after the period covered by the most recent ATA that was included in the Base TRR up through the termination of the Formula Rate. The Final True-Up Adjustment shall be calculated using the same methodology as the ATA in Schedule 4-ATA.

6.1.2 If the Final True-up Adjustment reflects an overcollection by PG&E, then PG&E shall be required to refund the amount of the Final True-up adjustment to its customers in its successor transmission rates to this Formula Rate. If the True-up Adjustment reflects an undercollection by PG&E, then PG&E shall be entitled and required to recover from its customers the amount of the Final True-up Adjustment in its successor transmission rates to this Formula Rate.

7. TRANSITION FROM THE PRIOR FORMULA RATE

The Prior Year for purposes of the initial True-Up Adjustment used in the Formula Rate is 2022, and the True-up Adjustment for 2022 will be calculated by the prior Model (established by FERC in Docket No. ER19-13) and entered into the Annual True-up Adjustment line in this Model for Rate Year 2024. The Prior Year for purposes of the second year of the Formula Rate is 2023, and the True-up Adjustment for 2023 (which is the Final True-up Adjustment from the prior Model) will also be calculated by the prior Model and entered into the Annual True-up Adjustment line in this Model for Rate Year 2025.

8. INCREMENTAL TRR

The ITRR, calculated in Schedule 2-ITRR of the Model, is the component of the Wholesale Base TRR that represents the amount of TRR, incremental to the Prior Year TRR, that PG&E anticipates during the upcoming Rate Year. The ITRR is based on the forecast of net plant additions that are expected to be in service by the end of the Rate Year multiplied by the Annual Fixed Charged Rate.

9. DEPRECIATION RATES

Depreciation rates for Transmission Plant, and Common, General, and Intangible Plant shall be as stated in Schedule 12-DepRates of the Model.

10. REVISIONS TO FORMULA RATE PROVISIONS

To address the circumstances described in Sections 10.1 to 10.8 below, PG&E may make a Section 205 filing seeking to change a single component in the Formula Rate or a party may make a Section 206 filing to revise a single component in the Formula Rate, but FERC is not bound by any single-issue filings from reviewing any or all components of the Formula Rate. A Section 205 filing or Section 206 filing is referred to as a "Filing" for purposes of this Section 10. All parties will have all applicable rights under the FPA and FERC's rules and regulations with respect to a Filing, except as limited by this Section 10. The Commission is not bound by this provision and may at its discretion broaden the scope of a Filing. No other single-issue rate filing is permitted under the Formula Rate. Parties reserve the right to protest or otherwise oppose a Filing and reserve all Section 206 rights with respect to any Filing.

10.1 Changes to FERC Form 1 or Uniform System of Accounts

PG&E will make a Filing to update the references in the Formula Rate to reflect any changes to the format and/or content of the FERC Form 1 or the Uniform System of Accounts that affect the calculations set forth in the Formula Rate in the event that a FERC order revises the format and/or content of the FERC Form 1 or the Uniform System of Accounts. This Filing shall be submitted within sixty (60) days of the later of: (1) the issuance of any FERC decision or directive to revise the FERC Form 1 or the Uniform System of Accounts; or (2) the date of implementation established in the FERC decision or directive for revisions to its FERC Form 1 or Uniform System of Accounts. In a proceeding commenced under this Section 10.1, the issues that can be addressed are whether the changes proposed by PG&E: (1) address the circumstances described in this Section 10.1; and (2) are just and reasonable.

10.2 Retail Transmission Rates

PG&E will make a Filing to revise Schedules 29-RetailRates-1 and 29-RetailRates-2 of the Formula Rate determination of retail transmission rates to reflect any change in Rate Groups, Rate Schedules, or the design of retail rates applicable to each Rate Schedule subsequent: (1) any final CPUC order that affects these aspects of retail transmission rates; and/or (2) California Energy Commission ("CEC") regulations and requirements in California Code of Regulations, Title 20, Division 2, Chapter 4, Article 5, Section 1623 (Section 1623), or subsequent CEC regulation superseding Section 1623. PG&E will make such a Filing only when the change in Rate Groups, Rate Schedules, or the design of retail rates cannot otherwise be reflected through the normal operation of the Formula Rate. In the Filing to FERC, PG&E will propose revisions to Schedules 29-RetailRates-1 and 29-RetailRates-2 of the Formula Rate that conform to the CPUC order and/or CEC regulation. In a proceeding commenced under this Section 10.2, the issues that can be addressed are whether the changes proposed by PG&E: (1) address the circumstances described in this Section 10.2; (2) are just and reasonable; and (3) correctly implement the applicable CPUC order and/or CEC regulation.

10.3 Depreciation Rates

PG&E may make a Filing to change the Common, General, and Intangible Plant depreciation rates in Schedule 12-DepRates upon approval by the CPUC of revised depreciation rates. PG&E will make such a Filing at FERC, as set forth in this section, between January 1 and March 1 of the year following the year that the CPUC order became effective. In a proceeding commenced under this Section 10.3, the issues that can be addressed are whether the changes proposed by PG&E: (1) address the circumstances described in this Section 10.3; (2) are just and reasonable; and (3) if applicable, correctly implement the applicable CPUC order.

10.4 Transmission Incentives

PG&E will make a Filing to revise the Formula Rate as needed to reflect non-ROE transmission incentives granted by FERC. In a proceeding commenced under this Section 10.4, the issues that can be addressed are whether the changes proposed by PG&E: (1) address the circumstances described in this Section 10.4; (2) are just and reasonable; and (3) correctly implement the applicable FERC order.

10.5 Project-Specific Incentives

If PG&E requests and is authorized by FERC to recover project-specific incentives, PG&E will make a Filing to include the project-specific incentive in its Formula Rate. In a proceeding commenced under this Section 10.5, the issues that can be addressed are whether the changes proposed by PG&E: (1) address the circumstances described in this Section 10.5; (2) are just and reasonable; and (3) correctly implement the applicable FERC order.

10.**6 Pacific Generation**

PG&E will make a Filing to revise the Formula Rate as needed to reflect any changes required by decisions issued by the CPUC and/or FERC after July 1, 2023 to allow the Formula Rate to fully reflect the specific accounting (e.g., operating expenses, rate base, and allocation factor) impacts regarding PG&E's proposed Pacific Generation transaction. In a proceeding commenced under this Section 10.6, the issues that can be addressed are whether the changes proposed by PG&E: (1) address the circumstances described in the decision issued by the CPUC and/or FERC; (2) are just and reasonable; and (3) correctly implement the applicable CPUC and/or FERC decision.

10.7 Wildfire Self-Insurance

PG&E will make a Filing to revise the Formula Rate as needed to reflect any changes required by decisions issued by the CPUC after July 1, 2023 to allow the Formula Rate to reflect any changes to the implementation of PG&E's wildfire self-insurance program approved by the CPUC in Decision 23-01-005, including, if applicable, the implementation of a subsequent wildfire insurance program. In a proceeding commenced under this Section 10.7, the issues that can be addressed are whether the changes proposed by PG&E: (1) address the circumstances described in the decision issued by the CPUC; (2) are just and reasonable; and (3) correctly implement the applicable CPUC decision.

10.8 Citizens Energy Transaction

PG&E will make a Filing to revise the Formula Rate as needed to reflect any changes required by or consistent with decisions issued by the CPUC and/or FERC after October 13, 2023 regarding transactions with Citizens Energy Corporation and/or a subsidiary thereof. In a proceeding commenced under this Section 10.8, the issues that can be addressed are whether the changes proposed by PG&E: (1) address the circumstances described in the decision issued by the CPUC and/or FERC; and (2) are just and reasonable.

11. NETWORK TRANSMISSION PLANT

Network Transmission Plant is a component of Rate Base that represents the Plant-in Service that serves customers from Low Voltage and/or High Voltage Facilities. PG&E adjusts the Transmission Plant reported in PG&E's FERC Form 1 for Asset Retirement costs, Generation Interconnection Plant, and Direct Connect Plant to arrive at the Network Transmission Plant. This calculation is found in Schedule 7-PlantInService.

12. NETWORK TRANSMISSION EXPENSE

12.1 Network Transmission O&M Expense

PG&E shall annually determine the amount of recorded Transmission O&M expense that is attributable to Network Transmission Plant. As set forth in Schedule 18-OandM of the Model, the method used to determine Network Transmission O&M Expense shall be to (1) adjust total recorded Transmission O&M Expense as stated in FERC Form 1, then (2) allocate recorded adjusted Transmission O&M Expense to Network Transmission O&M Expense based on a plant allocation factor found in Schedule 24-Allocators.

12.2 Network Transmission A&G Expense

PG&E shall annually determine the amount of recorded Transmission A&G expense that is attributable to Network Transmission. As set forth in Schedule 19-AandG of the Model, the method used to determine Network Transmission A&G Expense shall be to (1) adjust recorded total company A&G Expense as stated in FERC Form 1, then (2) allocate recorded adjusted total company A&G Expense to Network Transmission using either the Network Transmission O&M labor factor, the Network Transmission Plant asset factor, or a combination of the Network Transmission labor and plant factors, found in Schedule 24-Allocators.

12.3 Network Transmission Property Tax Expense

PG&E shall annually determine the amount of recorded Electric Property Tax expense that is attributable to Network Transmission. As set forth in Schedule 1-BaseTRR of the Model, the method used to determine the Network Transmission Property Tax Expense shall be to allocate the recorded Electric Property Tax expense as stated in FERC Form 1 using the Property Tax Allocation Factor found in Schedule 24-Allocators.

13. AMORTIZATION OF ABANDONED OR CANCELLED PROJECTS AND INCLUSION IN RATE BASE

For Abandoned or Cancelled Projects in Schedule 8-AbandonedProject, PG&E shall not begin amortization or include costs in Rate Base until recovery of those costs is approved by FERC through a Section 205 filing. In its Section 205 filing seeking approval for the recovery of Abandoned or Cancelled Project costs, PG&E shall propose to amortize those costs in its Formula Rate over a single year if the Abandoned or Cancelled Project costs for an individual project divided by PG&E's expected annual Gross Load is less than $0.05/Megawatt-hour ("MWh"). If the Abandoned or Cancelled Project costs divided by PG&E's annual Gross Load is equal to or greater than $0.05/MWh for any single project, PG&E shall propose to amortize the costs over a period longer than one year on a straight-line basis such that the costs will be recovered over the shorter of either: (1) a period that results in a rate impact to Network Electric

Transmission customers of $0.05/MWh in the initial year; or (2) the expected service life of the Abandoned or Cancelled Project asset.

14. USE OF INFORMATION

Information produced pursuant to these Protocols may be used in any proceeding concerning the Model, the Protocols, or the Annual Update; provided, however, that to the extent that any information provided pursuant to these Protocols has been designated and provided as Privileged Materials, subject to the provisions of Exhibit A to these Protocols, the use of such information shall be governed by Exhibit A.

This section shall not apply to any information produced in the course of FERC-established settlement proceedings pursuant to FERC's rules and regulations governing settlement.

15. EXCLUDED COSTS

In addition to costs that are generally determined by FERC to be non-recoverable, the costs for the following will not be included in the transmission revenue requirement or included in any account that informs the Model or any calculation in the Model:

15.1 General Advertising expenses except for safety, education and outreach related.

15.2 Lobbying and public relations expenses (civic/political).

15.3 Dues or other payments made to Electric Power Research Institute.

15.4 Donations and charitable contributions.

15.5 Asset Retirement Obligation related rate base items.

15.6 Abandoned or Cancelled Project costs. The intent of this exclusion is that PG&E cannot recover in rate base Abandoned or Cancelled Project costs unless the recovery of such costs in rate base is approved by FERC.

15.7 No ROE incentive adders related to Abandoned or Cancelled Project cost recovery. The intent of this exclusion is that no ROE incentive adders would apply to Abandoned or Cancelled Project costs, but this would not preclude PG&E recovering Abandoned or Cancelled Project costs if approved by FERC or other non-ROE incentives.

15.8 Merger Goodwill in capital structure, unless approved by FERC.

15.9 Penalties, fines, or disallowances, imposed by a regulatory body or court in a final decision or order.

15.10 PG&E will remove all officer compensation and benefits from Accounts 920, 923, and 926 for Securities and Exchange Commission Section 3b-7 officers. PG&E will provide a workpaper showing the removal of officer compensation and benefits consistent with this provision.

16. LIST OF WORKPAPERS

The following is a list of workpapers that will be provided by PG&E to the Interested Parties with the Draft Annual Update and, upon request, when the Annual Update is filed at FERC. PG&E will notify the Interested Parties of any changes or additions to the workpapers, other than populating the workpapers.

WP 1-BaseTRR_Pyrl_Tax

WP_1-BaseTRR_Tax

WP_7-PlantInService

WP_8-AbandonedPlant

WP_9-PlantAdditions

WP_10-AccDep

WP_11-Depreciation

WP_14-ADIT

WP_15-NUC_EoYandBoY

WP_18-OandM

WP_19-AandG

WP_21-NPandS

WP_23-RetailSGTax

WP_24-Allocators_Labor

WP_25-RFandUFactors

WP_28-GrossLoad

WP_29-RetailRates-PUBLIC

WP_Tax_Support

WP_Tax_Support2

WP_Self-Insurance

WP_AFUDC

EXHIBIT A

NON-DISCLOSURE AGREEMENT

1. This Non-Disclosure Agreement shall govern the use of all Privileged Materials produced by, or on behalf of, any Participant in relation to Pacific Gas and Electric Company's ("PG&E") initial Transmission Owner ("TO") tariff formula rate filing, Annual Update filings, or subsequent proceedings at the Federal Energy Regulatory Commission ("FERC") to update PG&E's TO tariff formula rate. This Non-Disclosure Agreement shall remain in effect until all Privileged Materials are returned to the producing Participant or destroyed by the receiving Participant, as described herein.

2. This Non-Disclosure Agreement applies to the following two categories of materials: (A) a Participant may designate as Privileged those materials which customarily are treated by that Participant as sensitive, private, proprietary or otherwise confidential, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to a risk of competitive disadvantage, breach of confidentiality requirements or commitments, or other business injury; and (B) a Participant shall designate as Privileged those materials which contain critical energy infrastructure information, as defined in 18 CFR § 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions – For purposes of this Agreement:

   (a) The term "Participant" shall mean a Participant as defined in 18 CFR § 385.102(b).

   (b)(1) The term "Privileged Materials" means: (A) materials provided by a Participant in response to a request from another Participant, or in response to settlement discovery requests, and designated by the producing Participant as Privileged; (B) any information contained in or obtained from such designated materials; (C) notes of Privileged Materials; and (D) copies of Privileged Materials. The Participant producing the Privileged Materials shall physically mark them on each page as "PRIVILEGED MATERIALS," or with words of similar import as long as the term "Privileged Materials" is included in that designation, to indicate that they are Privileged Materials. If the Privileged Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information; Do Not Release."

   (2) The term "Notes of Privileged Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Privileged Materials are subject to the same restrictions provided in this Agreement for Privileged Materials.

   (3) Privileged Materials shall not include: (A) any information or document that has been filed with and accepted into the public files of the Federal Energy Regulatory

Commission ("Commission"), or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court; or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Non-Disclosure Agreement. Privileged Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Privileged Materials shall certify their understanding that such access to Privileged Materials is provided pursuant to the terms and restrictions of this Non-Disclosure Agreement, and that such Participants have read the Non-Disclosure Agreement and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) Commission Trial Staff ("Staff") designated as such in this proceeding;

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) an attorney, paralegal, or other employee associated for purposes of this case with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of evaluating the filing made in this docket or advising, preparing for or negotiating a settlement of this proceeding; or

(5) an employee or other representative of a Participant appearing in this proceeding with significant responsibility for this docket.

4. Privileged Materials shall be made available under the terms of this Non-Disclosure Agreement only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Privileged Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Privileged Material is concluded and no longer subject to judicial review. After that date, the Participants shall, within fifteen days of such date, return the Privileged Materials (excluding Notes of Privileged Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Privileged Materials, and Notes of Privileged Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each

Participant shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Privileged Materials and all Notes of Privileged Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Privileged Materials are not returned or destroyed, they shall remain subject to this Non-Disclosure Agreement.

6. All Privileged Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. For documents submitted to Staff, Staff shall follow the notification procedures of 18 CFR § 388.112 before making public any Privileged Materials.

7. Privileged Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 9. Privileged Materials shall not be used except as necessary to evaluate the filing made in this docket or for the conduct of settlement efforts in this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Privileged Materials, but such copies become Privileged Materials. Reviewing Representatives may make notes of Privileged Materials, which shall be treated as Notes of Privileged Materials if they disclose the contents of Privileged Materials. Privileged Materials including without limitation when associated with any information that can reasonably be used to identify an individual, consumer, family, household, residence or non-residential customer shall be protected by each Participant using reasonable security procedures and practices to protect such information from unauthorized access, use, modification or disclosure, including, without limitation, encryption of the Privileged Materials, password-protected workstations, and documented training of all persons with access to the Privileged Materials. Under no circumstances shall any Participant receiving Privileged Materials sell or obtain any consideration for transfer of the Privileged Materials to any third party.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Privileged Materials obtained through this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3 (d) above, the Participant shall seek agreement from the Participant providing the Privileged Materials. If an agreement is reached, that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, that person shall not be given access to Privileged Materials.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Privileged Materials pursuant to this Non-Disclosure Agreement unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Privileged Material to that Reviewing Representative.

   (b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Agreement.

10. Any Reviewing Representative may disclose Privileged Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Privileged Materials are disclosed ceases to be engaged in these proceedings or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Privileged Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Non-Disclosure Agreement and the certification.

11. Nothing in this Non-Disclosure Agreement shall be construed as precluding any Participant from objecting to the use of Privileged Materials on any legal grounds.

12. Nothing in this Non-Disclosure Agreement shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Non-Disclosure Agreement.

13. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Privileged Materials.

14. The contents of Privileged Materials or any other form of information that copies or discloses Privileged Materials shall not be disclosed to anyone other than in accordance with this Non-Disclosure Agreement and shall be used only in connection with evaluating the filing made in this docket or in connection with settlement discussions in this proceeding.

15. Notwithstanding the provisions of this Non-Disclosure Agreement, the following applies only with regard to the California Public Utilities Commission ("CPUC"):

(a) Nothing in this Agreement precludes a Reviewing Representative of the CPUC from sharing Privileged Materials, Notes of Privileged Materials, or information derived from Privileged Materials, with their supervisors, CPUC Commissioners, Commissioner advisors, or other CPUC staff (collectively "CPUC Personnel") as occurs in the normal course of confidential communications within the CPUC and without individually designating such CPUC Personnel as Reviewing Representatives.

(b) If Privileged Materials, Notes of Privileged Materials, or information derived from Privileged Materials are provided to CPUC Personnel, the individual(s) receiving the Privileged Materials shall be informed of the terms of this Non-Disclosure Agreement and shall be informed that they are to maintain the Privileged Materials, Notes of Privileged Materials, or information derived from Privileged Materials as confidential consistent with the terms of this Non-Disclosure Agreement. In addition, all Privileged Materials, Notes of Privileged Materials, or information derived from Privileged Materials provided to CPUC Personnel shall be marked to indicate that Privileged Materials are being provided subject to the terms of this Non-Disclosure Agreement.

16. This Agreement shall be governed and construed according to the laws of the State of California. Participants agree to comply with all applicable federal, state and local laws governing the protection of the Privileged Materials, including, without limitation, the California Consumer Privacy Act and all applicable laws, rules and regulations protecting consumer privacy.

End

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Privileged Materials is provided to me pursuant to the terms and restrictions of the Non-Disclosure Agreement in this proceeding, that I have been given a copy of and have read the Non-Disclosure Agreement, and that I agree to be bound by it. I understand that the contents of the Privileged Materials, any notes or other memoranda, or any other form of information that copies or discloses Privileged Materials, shall not be disclosed to anyone other than in accordance with that Non-Disclosure Agreement.

By: ____________________________________

Printed Name: ____________________________________

Title: ____________________________________

Representing: ____________________________________

Date: ____________________________________

Email: ____________________________________

Pacific Gas and Electric Company
Transmission Owner Tariff

Appendix VIII: Formula Rate
Attachment 2: Model

Pacific Gas and Electric Company
Transmission Owner Tariff
Appendix VIII: Formula Rate
Attachment 2: Model

Table of Contents

25-RFandUFactors	Revenue Fees and Uncollectible Factors
26-WholesaleTRRs	High and Low Voltage Wholesale Revenue Requirement
27-WholesaleRates	Calculation of PG&E Wholesale Rates
28-GrossLoad	Calculation of Gross Load at the CAISO Interface (Area Out)
29-RetailRates-1	Proposed Retail Rates
29-RetailRates-2	Proposed Allocations & Revenues
30-WFSelfInsurance	Wildfire Self-Insurance
31-COO	Cost of Ownership Rates
32-CWIPIncentive	CWIP Incentive - Recorded CWIP for Projects Approved for CWIP Incentive

Formatting and References

FORMATTING:

Shading

In the Schedules and Workpapers, those cells shaded in gold are inputs to the Formula Rate Model.

Number Format

Excel “Currency” number format is used.

Reference Order

Reference order: page (or tab) number, line number, column number, note number. A comma separates each reference element. Notes contained in the FERC Form 1 are not numbered (see example below).

Workpaper Naming Conventions

Workpaper names are prefaced with “WP_” followed by the schedule name to which it corresponds (e.g.: WP_18-O&M). If workpapers in support of a Schedule come from different sources or support distinctly different sections of a Schedule, the workpaper name includes a short description suffix (e.g.: WP_25-RFandUFactors_FF, where FF describes Franchise Fees).

Workpaper Tabs and Structure

Workpaper tabs are numbered and do not have names or otherwise attempt to describe the contents of the workpaper with the exception of the Table of Contents sheet.

The first sheet of a workpaper with multiple sheets is a Table of Contents. The tab for the Table of Contents sheet is named “TOC”. The TOC sheet lists the tab number and the description of the workpaper contents taken from the workpaper heading.

REFERENCES:

REFERENCE	FORM OF REFERENCE	EXAMPLE	NOTES
Column	col (column # or letter)	col k or col 6	
FERC Form No. 1	FF1	FF1 337.2, L. 20, col k FF1 234, Note(s)	
Line (internal reference)	Line (line #)	Line 25	Internal reference – source within the same Schedule or Workpaper sheet
Line (external reference)	L. (line #)	L. 25	External reference – source outside the Schedule or Workpaper sheet
Note	Note(s) (note #, if provided)	Note 1 14-ADIT, Note 1 FF1 450.1, Notes	
Page	(page #)	337.2 or 2-24 337.2, L. 10, col k	Nothing precedes the page number(s).
Schedule	(schedule name)	12-DepRates	Nothing precedes the schedule name
Tabs	(tab #)	WP_29-RetailRates-2 4 WP_28-GrossLoad 2, L. 115, col 6	Nothing precedes the tab number.

Line for extra data	...	...	Some Schedules have a"..." row. These rows are intended for new data to be added in a future update.

Schedule 1-BaseTRR
Base Transmission Revenue Requirement
Input cells are shaded gold

Rate Year:
Prior Year: -2

1) Rate Base

Line		Description	Values	Source	Notes	Line	
		Plant					
100		Transmission Functional Plant	$0	7-PlantInService, L. 112, col 13	End of Year Value	**100**	
101		Common + General + Intangible Plant	#DIV/0!	7-PlantInService, L. 401, col 3	End of Year Value	**101**	
102		Abandoned or Cancelled Projects	$0	8-AbandonedProject, L. 102, col 11	End of Year Value	**102**	
103		**Total Plant**	**#DIV/0!**	Sum of Lines 100 to 102		**103**	
		Working Capital					
104		Materials and Supplies	$0	13-WorkCap, L. 112, col 2	End of Year Value	**104**	
105		Prepayments	#DIV/0!	13-WorkCap, L. 217, col 5	End of Year Value	**105**	
106		Cash Working Capital	#DIV/0!	(Line 500 + Line 501) / 8		**106**	
107		**Total Working Capital**	**#DIV/0!**	Sum of Lines 104 to 106		**107**	
		Accumulated Depreciation Reserve					
108		Transmission Functional Depreciation Reserve	$0	10-AccDep, L. 112, col 13	Negative End of Year Value	**108**	
109		Common + General + Intangible Depreciation Reserve	#DIV/0!	10-AccDep, L. 401, col 3	Negative End of Year Value	**109**	
110		**Total Accumulated Depreciation Reserve**	**#DIV/0!**	Line 108 + Line 109		**110**	
111	**a**	**Accumulated Deferred Income Taxes**	#DIV/0!	14-ADIT, L. 104, col 2	End of Year Value	**111**	**a**
111	**b**	**(Excess)/Deficient Accumulated Deferred Income Taxes**	$0	17-RegAssets-1, L. 201	End of Year Value	**111**	**b**
111	**c**	**Total (Excess)/Deficient and Accumulated Deferred Income Taxes**	**#DIV/0!**	Line 111a + Line 111b	End of Year Value	**111**	**c**
112		**Network Upgrade Credits (Customer Advances)**	$0	15-NUC, L. 103	Negative End of Year Value	**112**	
113		**Unfunded Reserves**	#DIV/0!	16-UnfundedReserves, L. 101	End of Year Value	**113**	
114		**Other Regulatory Assets or Liabilities**	$0	17-RegAssets-1, L. 100	End of Year Value	**114**	
115		**CWIP Incentive**	$0	32-CWIPIncentive, L. 100, col 16	End of Year Value	**115**	
116		**Rate Base**	**#DIV/0!**	Sum of Lines 103, 107, 110 and Lines 111c to 115		**116**	

2) ROE and Capitalization Calculations

Line	Description	Values	Source	Notes	Line
	Debt				
200	Long Term Debt Amount	$0	5-CostofCap-1, L. 103	13-month average	**200**
201	Long Term Debt Cost Percentage	#DIV/0!	5-CostofCap-2, L. 114	13-month average	**201**
202	**Cost of Long Term Debt**	**#DIV/0!**	Line 200 * Line 201		**202**
	Preferred Stock				
203	Preferred Stock Amount	$0	5-CostofCap-1, L. 107	13-month average	**203**
204	Preferred Stock Cost Percentage	#DIV/0!	5-CostofCap-3, L. 106	13-month average	**204**
205	**Cost of Preferred Stock**	**#DIV/0!**	Line 203 * Line 204		**205**
	Equity				
206	Common Stock Equity Amount	$0	5-CostofCap-1, L. 112	13-month average	**206**
207	**Total Capital**	**$0**	Line 200 + Line 203 + Line 206		**207**
	Capital Percentages				
208	Long Term Debt Capital Percentage	#DIV/0!	Line 200 / Line 207		**208**
209	Preferred Stock Capital Percentage	#DIV/0!	Line 203 / Line 207		**209**
210	Common Stock Capital Percentage	#DIV/0!	Line 206 / Line 207		**210**
	Annual Cost of Capital Components				
211	Long Term Debt Cost Percentage	#DIV/0!	Line 201		**211**
212	Preferred Stock Cost Percentage	#DIV/0!	Line 204		**212**

Base Transmission Revenue Requirement
Input cells are shaded gold

Rate Year:
Prior Year: -2

213	**Total Return on Common Equity**	**0.00%**	Sum Lines 214 and 215	**213**
214	PG&E Return on Common Equity			**214**
215	FERC ISO Participation Incentive Adder	0.00%		**215**
	Calculation of Cost of Capital Rate			
216	Weighted Cost of Long Term Debt	#DIV/0!	Line 208 * Line 211	**216**
217	Weighted Cost of Preferred Stock	#DIV/0!	Line 209 * Line 212	**217**
218	Weighted Cost of Common Stock	#DIV/0!	Line 210 * Line 213	**218**
219	**Cost of Capital Rate**	**#DIV/0!**	Sum of Lines 216 to 218	**219**
220	**Equity Rate of Return Including Common and Preferred Stock**	#DIV/0!	Line 217 + Line 218	**220**
221	**FERC Participation Incentive Rate of Return**	#DIV/0!	Line 210 * Line 215	**221**
222	Return on Capital: Rate Base times Cost of Capital Rate	#DIV/0!	Line 219 * Line 116	**222**
223	Remove Return on Abandoned or Cancelled Projects from FERC Participation Incentive	#DIV/0!	Line 102 * Line 221	**223**
224	**Total Return on Capital**	**#DIV/0!**	Line 222 - Line 223	**224**

Base Transmission Revenue Requirement | **Rate Year:**
Input cells are shaded gold | **Prior Year:** -2

3) Other Taxes

Line		Description	Values	Source	Notes	Line	
		Property Taxes					
300		Sub-Total Local Taxes		FF1 262-263, L. 10, col l		**300**	
301		Net Plant Property Tax Allocation Factor	#DIV/0!	24-Allocators, L. 141		**301**	
302		**Total Transmission Property Taxes**	**#DIV/0!**	Line 300 * Line 301		**302**	
		Payroll Tax Expense					
303		Fed Ins Cont Amt -- Current		FF1 262-263, L. 8, col l		**303**	
304		CA SUI Current		FF1 262-263, L. 2, col l		**304**	
305		Fed Unemp Tax Act- Current		FF1 262-263, L. 1, col l		**305**	
306		Business Taxes		WP_1-BaseTRR_Pyrl_Tax 1, L. 106b	Portion of FF1, 262-263, L11, col l Total	**306**	
307		SF Pyrl Exp Tx		WP_1-BaseTRR_Pyrl_Tax 1, L. 107	Portion of FF1, 262-263, L11, col l Total	**307**	
308		**Total Electric Payroll Tax Expense**	**$0**	Sum of Lines 303 to 307		**308**	
309		Network Transmission Labor Factor (Total Electric)	#DIV/0!	24-Allocators, L. 112		**309**	
310		**Total Transmission Payroll Tax Expense**	**#DIV/0!**	Line 309 * Line 308		**310**	
311		**Total Other Taxes**	**#DIV/0!**	Line 302 + Line 310		**311**	

4) Income Taxes

Line		Description		Source	Notes	Line	
400		Federal Income Tax Rate	0.00%	22-TaxRates, L. 100		**400**	
401		State Income Tax Rate	0.00%	22-TaxRates, L. 101		**401**	
402		**Composite Tax Rate**	**0.00%**	(Line 400 + Line 401) - (Line 400 * Line 401)		**402**	
		Calculation of Flowthrough and Permanent Tax Deductions (FPD):					
403		Book Depreciation of AFUDC Equity Book Basis				**403**	
403	**a**	AFUDC Equity Book Depreciation - Total Direct		WP_1-BaseTRR_Tax 1, L. 103		**403**	**a**
403	**b**	Network Electric Transmission Plant Factor (Total Transmission)	#DIV/0!	24-Allocators, L. 122		**403**	**b**
403	**c**	Total Allocated Direct Plant	#DIV/0!	Line 403a * Line 403b		**403**	**c**
403	**d**	AFUDC Equity Book Depreciation - Total Common		WP_1-BaseTRR_Tax 1, L. 117		**403**	**d**
403	**e**	Network Transmission Plant Factor (Total Company)	#DIV/0!	24-Allocators, L. 116		**403**	**e**
403	**f**	Total Allocated Common Plant	#DIV/0!	Line 403d * Line 403e		**403**	**f**
403	**g**	Total Allocated Direct and Common	**#DIV/0!**	Line 403c + Line 403f		**403**	**g**
404		**Flowthrough and Permanent Tax Deductions**	**#DIV/0!**	Line 403g		**404**	
		Calculation of Credits and Other (CO):					
405		Amortization of (Excess) Deficient Deferred Tax Liability			Note 1	**405**	
405	**a**	Amortization of Excess Deferred Tax Liability - Non Protected		WP_1-BaseTRR_Tax 3, L. 101		**405**	**a**
405	**b**	Amortization of Excess Deferred Tax Liability - Protected		WP_1-BaseTRR_Tax 3, L. 106		**405**	**b**
405	**c**	Network Electric Transmission Plant Factor (Total Transmission)	#DIV/0!	24-Allocators, L. 122		**405**	**c**
405	**d**	Total Allocated Direct Plant	#DIV/0!	Line 405b * Line 405c		**405**	**d**
405	**e**	Common Function Group		WP_1-BaseTRR_Tax 3, L. 122		**405**	**e**
405	**f**	Network Transmission Plant Factor (Total Company)	#DIV/0!	24-Allocators, L. 116		**405**	**f**
405	**g**	Total Allocated Common	#DIV/0!	Line 405e * Line 405f		**405**	**g**
405	**h**	Amortization of Excess Deferred Tax Asset - NOL (Protected)		WP_1-BaseTRR_Tax 3, L. 125		**405**	**h**
405	**i**	Total Protected (ARAM) and Non-Protected	**#DIV/0!**	Line 405a + Line 405d + Line 405g + Line 405h		**405**	**i**
406		Federal and State Tax Credits before Allocation		WP_1-BaseTRR_Tax 2, L. 101		**406**	
406	**a**	Network Transmission Labor Factor (Total Company)	#DIV/0!	24-Allocators, L. 113		**406**	**a**
406	**b**	Federal and State Tax Credits after Allocation	**#DIV/0!**	Line 406 * Line 406a		**406**	**b**
407		**Credits and Other**	**#DIV/0!**	Line 405i + Line 406b		**407**	

Base Transmission Revenue Requirement | **Rate Year:**
Input cells are shaded gold | **Prior Year: -2**

408	**Income Taxes:**	**#DIV/0!**	Line 409	**408**
409	Income Taxes = [((RB * ER) + FPD - RAP) * (CTR/(1 – CTR))] + CO/(1 – CTR)]			**409**
	Where:			
410	RB = Rate Base	#DIV/0!	Line 116	**410**
411	ER = Equity Rate of Return Including Common and Preferred Stock	#DIV/0!	Line 220	**411**
412	CTR = Composite Tax Rate	0.00%	Line 402	**412**
413	CO = Credits and Other	#DIV/0!	Line 407	**413**
414	FPD = Flowback and Permanent Tax Deductions	#DIV/0!	Line 404	**414**
415	RAP = Return on Abandoned or Cancelled Projects From CAISO Participation Incentive	#DIV/0!	Line 223	**415**

Base Transmission Revenue Requirement | **Rate Year:**
Input cells are shaded gold | **Prior Year: -2**

Line	Description	Values	Source	Notes	Line
	5) Prior Year Transmission Revenue Requirement				
Line	**Description**	**Values**	**Source**	**Notes**	**Line**
	Prior Year TRR Components				
500	O&M Expense	#DIV/0!	18-OandM, L. 100, col 15		**500**
501	A&G Expense	#DIV/0!	19-AandG, L. 219		**501**
502	Network Upgrade Interest Expense	$0	15-NUC, L. 106		**502**
503	Depreciation Expense (incl. Common + General + Intangible)	#DIV/0!	11-Depreciation, L. 102, col 13 + L. 200, col 3		**503**
504	Depreciation Expense - Rate Adjustment	$0	11-Depreciation, L. 602		**504**
505	Abandoned or Cancelled Projects Amortization Expense	$0	8-AbandonedProject, L. 102, col 7		**505**
506	Return on Capital	#DIV/0!	Line 224		**506**
507	Other Taxes	#DIV/0!	Line 311		**507**
508	Income Taxes	#DIV/0!	Line 408		**508**
509	Revenue Credits	$0	20-RevenueCredits, L. 100, col 7 + L. 1001, col 5	Negative Value	**509**
510	NP&S Credit	$0	21-NPandS, L. 403	Negative Value	**510**
511	Amortization and Regulatory Debits/Credits	$0	17-RegAssets-1, L. 102	Note 2	**511**
512	**Total without FF, Uncollectibles, and South Georgia**	**#DIV/0!**	Sum of Lines 500 to Line 511		**512**
	SFGR Tax and Franchise Fees				
513	Franchise Fees Factor	#DIV/0!	25-RFandUFactors, L. 400		**513**
514	SFGR Tax Factor	#DIV/0!	25-RFandUFactors, L. 401		**514**
515	**Total SFGR Tax and Franchise Fees**	**#DIV/0!**	Line 512 * (Line 513 + Line 514)		**515**
516	**Prior Year TRR**	**#DIV/0!**	Line 512 + Line 515		**516**
	5a) Self-Insurance Funding				
Line	**Description**	**Values**	**Source**	**Notes**	**Line**
517	Wildfire Self-Insurance Initial Funding	#DIV/0!	30-WFSelfInsurance, L. 107, col 2		**517**
518	Wildfire Self-Insurance Replenishment Funding	#DIV/0!	30-WFSelfInsurance, L. 209, col 2		**518**
519	**Total Self-Insurance**	**#DIV/0!**	Line 517 + Line 518		**519**
520	**Total Self-Insurance SFGR Tax and Franchise Fees**	#DIV/0!	Line 519 * (Line 513 + Line 514)		**520**
521	**Total Rate Year Self-Insurance**	**#DIV/0!**	Line 519 + Line 520		**521**
	6) Wholesale Base Transmission Revenue Requirement				
Line	**Description**	**Values**	**Source**	**Notes**	**Line**
600	Prior Year TRR	#DIV/0!	Line 516		**600**
600 a	Rate Year Self-Insurance	#DIV/0!	Line 521		**600 a**
601	ITRR	#DIV/0!	2-ITRR, L. 209		**601**
602	Annual True-up Adjustment	$0	4-ATA, L. 404	Note 3	**602**
603	**Wholesale Base Transmission Revenue Requirement**	**#DIV/0!**	Sum of Lines 600 to Line 602		**603**
	7) Base Transmission Revenue Requirement				
Line	**Description**	**Values**	**Source**	**Notes**	**Line**
700	Uncollectibles Factor	#DIV/0!	25-RFandUFactors, L. 402		**700**
701	Uncollectibles Expense	#DIV/0!	Line 700 * Line 603		**701**
702	Retail (South Georgia) Tax Adjustment	#DIV/0!	23-RetailSGTax, L. 305, col 3		**702**
703	Wholesale Base Transmission Revenue Requirement	#DIV/0!	Line 603		**703**
704	**Retail Base Transmission Revenue Requirement**	**#DIV/0!**	Sum of Lines 701 to Line 703		**704**

Notes:
1) The 'Amortization of Excess Deferred Tax Liability' amount was included in the TO19 Settlement filed on September 21, 2018 and approved by the Commission on December 20, 2018 in 165 FERC ¶ 61,244 (2018). The amount shown equals protected and unprotected amortization.
2) For FERC authorized Other Regulatory Assets in Section 1 of Schedule 17-RegAssets1, which are not otherwise recovered in O&M or A&G expenses.
3) The Annual True-up Adjustments for Prior Year 2022 and 2023 are calculated in the TO20 Model, Schedule 4-ATA and will be included in this TO21 Model, Schedule 4-ATA, Line 403. The Annual True-up Adjustments for Prior Year

Base Transmission Revenue Requirement **Rate Year:**

Input cells are shaded gold **Prior Year: -2**

2024 and after are calculated in this TO21 Model, Schedule 4-ATA. The Annual True-up Adjustments for Prior Year 2024 and after will be shown on this model, Schedule 4-ATA, Lines 400-402. In TO21, Schedule 4-ATA, Line 404, formula is set up to pick up the appropriate annual true-up amount based on the prior year for Line 602 of this schedule.

...

Schedule 2-ITRR
Incremental Transmission Revenue Requirement

Rate Year:
Prior Year: -2

Line	Description	Values	Source	Notes	Line
	1) Annual Fixed Charge Rate ("AFCR") Calculation				
Line	**Description**	**Values**	**Source**	**Notes**	**Line**
100	AFCR = Prior Year TRR / Net Plant				**100**
	Determination of Net Plant:				
101	Transmission Functional Plant:	$0	7-PlantInService, L. 112, col 13		**101**
102	Transmission Functional Accumulated Depreciation:	$0	10-AccDep, L. 112, col 13		**102**
103	**Net Plant:**	**$0**	Line 101 - Line 102		**103**
	Determination of AFCR:				
104	Prior Year TRR without RF&U:	#DIV/0!	1-BaseTRR, L. 512 - [50%*(1-BaseTRR, L. 500 + L. 501)]		**104**
104a	Less: Abandoned or Cancelled Projects Amortization Expense	$0	1-BaseTRR, L. 505	Negative	**104a**
105	Less: Depreciation Expense	#DIV/0!	1-BaseTRR, L. 503 + L. 504 - 11-Depreciation, L. 200, col 3	Negative	**105**
106	Less: Impact of ADIT	#DIV/0!	(1-BaseTRR, L. 111c x 1-BaseTRR, L. 220) x (1+(1-BaseTRR, L. 402)/(1 - 1-BaseTRR, L. 402)) + (1-BaseTRR, L. 111c x 1-BaseTRR, L 216)	Negative	**106**
107	**AFCR Applicable TRR**	**#DIV/0!**	Line 104 + Line 104a + Line 105 + Line 106		**107**
108	AFCR:	#DIV/0!	Line 107 / Line 103		**108**
	2) Calculation of ITRR				
Line	**Description**	**Values**	**Source**	**Notes**	**Line**
200	Forecast Net Plant Additions Balance:	#DIV/0!	9-PlantAdditions, L. 124, col 6		**200**
201	AFCR:	#DIV/0!	Line 108		**201**
202	AFCR prior to Depreciation & ADIT Impacts	#DIV/0!	Line 200 * Line 201		**202**
203	Add: Depreciation Expense	#DIV/0!	9-PlantAdditions, L. 125, Col 3		**203**
204	Add: Impact of ADIT	#DIV/0!	14-ADIT, L. 728, Col 11		**204**
205	**ITRR without RF&U:**	**#DIV/0!**	Sum Line 202 to Line 204		**205**
206	Franchise Fees Factor	#DIV/0!	1-BaseTRR, L. 513		**206**
207	SFGR Tax Factor	#DIV/0!	1-BaseTRR, L. 514		**207**
208	**Total SFGR Tax and Franchise Fees**	**#DIV/0!**	Line 205 * (Line 207 + Line 206)		**208**
209	**Incremental Forecast Period TRR:**	**#DIV/0!**	Line 205 + Line 208		**209**

Notes:
...

Schedule 3-True-upTRR
True-up Transmission Revenue Requirement **Prior Year: -2**
Input cells are shaded gold

1) Rate Base

Line		Description	Values	Source	Notes	Line	
		Plant					
100		Transmission Functional Plant	$0	7-PlantInService, L. 113, col 13	13-Month Avg	**100**	
101		Common + General + Intangible Plant	#DIV/0!	7-PlantInService, L. 402, col 3	BOY EOY Avg	**101**	
102		Abandoned or Cancelled Projects	$0	8-AbandonedProject, L. 102, col 12	BOY EOY Avg	**102**	
103		**Total Plant**	**#DIV/0!**	Sum of Lines 100 to 102		**103**	
		Working Capital					
104		Materials and Supplies	$0	13-WorkCap, L. 113, col 2	13-Month Avg	**104**	
105		Prepayments	#DIV/0!	13-WorkCap, L. 215, col 5	13-Month Avg	**105**	
106		Cash Working Capital	#DIV/0!	(Line 400 + Line 401) / 8		**106**	
107		**Total Working Capital**	**#DIV/0!**	Sum of Lines 104 to 106		**107**	
		Accumulated Depreciation Reserve					
108		Transmission Functional Depreciation Reserve	$0	10-AccDep, L. 113, col 13	Negative 13-Month Avg	**108**	
109		Common + General + Intangible Depreciation Reserve	#DIV/0!	10-AccDep, L. 402, col 3	Negative BOY EOY Avg	**109**	
110		**Total Accumulated Depreciation Reserve**	**#DIV/0!**	Line 108 + Line 109		**110**	
111	**a**	**Accumulated Deferred Income Taxes**	#DIV/0!	14-ADIT, L. 108, col 2	Weighted Average	**111**	**a**
111	**b**	**(Excess)/Deficient Accumulated Deferred Income Taxes**	$0	17-RegAssets-1, L. 202	Weighted Average	**111**	**b**
111	**c**	**Total (Excess)/Deficient and Accumulated Deferred Income Taxes**	#DIV/0!	Line 111a + Line 111b	Weighted Average	**111**	**c**
112		**Network Upgrade Credits (Customer Advances)**	#DIV/0!	15-NUC, L. 109	Negative BOY EOY Avg	**112**	
113		**Unfunded Reserves**	#DIV/0!	16-UnfundedReserves, L. 100	13-Month Avg	**113**	
114		**Other Regulatory Assets or Liabilities**	$0	17-RegAssets, L. 101	BOY EOY Avg	**114**	
115		**CWIP Incentive**	$0	32-CWIPIncentive, L. 100, col 17	13-Month Avg	**115**	
116		**Rate Base**	**#DIV/0!**	Sum of Lines 103, 107, 110 and Lines 111c to 115		**116**	

2) ROE and Capitalization Calculations
Instructions:
1) Input the ROE for the Prior Year on Line 200.

Line	Description	Values	Source	Notes	Line
200	Prior Year Return on Common Equity			ROE from Schedule 1; if there are mid-year changes, a workpaper will be provided	**200**
	Calculation of Cost of Capital Rate				
201	Weighted Cost of Long Term Debt	#DIV/0!	1-BaseTRR, L. 216	13-Month Avg	**201**
202	Weighted Cost of Preferred Stock	#DIV/0!	1-BaseTRR, L. 217		**202**
203	Weighted Cost of Common Stock	#DIV/0!	Line 200 * 1-BaseTRR, L. 210		**203**
204	**Cost of Capital Rate**	**#DIV/0!**	Sum of Lines 201 to 203		**204**
205	**Equity Rate of Return Including Common and Preferred Stock**	**#DIV/0!**	Line 202 + Line 203		**205**

	True-up Transmission Revenue Requirement			**Prior Year: -2**
	Input cells are shaded gold			
206	**FERC Participation Incentive Rate of Return**	**#DIV/0!**	1-BaseTRR, L. 221	**206**
207	Return on Capital: Rate Base times Cost of Capital Rate	#DIV/0!	Line 204 * Line 116	**207**
208	Remove Return on Abandoned or Cancelled Projects from FERC Participation Incentive	#DIV/0!	Line 102 * Line 206	**208**
209	**Total Return on Capital**	**#DIV/0!**	Line 207 - Line 208	**209**

True-up Transmission Revenue Requirement **Prior Year: -2**

Input cells are shaded gold

3) Income Taxes

Instructions:

1) Input the Prior Year Federal and State Income Tax Rates if they are different from the Rate Year Tax Rates.

Line	Description	Values	Source	Notes	Line
300	Federal Income Tax Rate	0.00%	22-TaxRates, L. 200		**300**
301	State Income Tax Rate	0.00%	22-TaxRates, L. 201		**301**
302	**Composite Tax Rate**	**0.00%**	(Line 300 + Line 301) - (Line 300 * Line 301)		**302**
303	**Income Taxes:**	**#DIV/0!**	Line 304		**303**
304	Income Taxes = [(((RB * ER) + FPD - RAP) * (CTR/(1 – CTR))] + CO/(1 – CTR]				**304**
	Where:				
305	RB = Rate Base	#DIV/0!	Line 116		**305**
306	ER = Equity Rate of Return Including Common and Preferred Stock	#DIV/0!	Line 205		**306**
307	CTR = Composite Tax Rate	0.00%	Line 302		**307**
308	CO = Credits and Other	#DIV/0!	1-BaseTRR, L. 407		**308**
309	FPD = Flowback and Permanent Tax Deductions	#DIV/0!	1-BaseTRR, L. 404		**309**
310	RAP = Return on Abandoned or Cancelled Projects From FERC Participation Incentive	#DIV/0!	Line 208		**310**

4) True-up Transmission Revenue Requirement

Instructions:

1) Input the Annual True-up Adjustment that was included in the Prior Year's rates on Line 419 and input the Rate Year the ATA trued-up. (For example, if the Prior Year is 2022, then the ATA that was included in the 2022 rates was the ATA for 2020.)

Line	Description	Values	Source	Notes	Line
	Prior Year TRR Components				
400	O&M Expense	#DIV/0!	1-BaseTRR, L. 500		**400**
401	A&G Expense	#DIV/0!	1-BaseTRR, L. 501		**401**
402	Network Upgrade Interest Expense	$0	1-BaseTRR, L. 502		**402**
403	Depreciation Expense (incl. Common + General + Intangible)	#DIV/0!	1-BaseTRR, L. 503		**403**
404	Abandoned or Cancelled Projects Amortization Expense	$0	8-AbandonedProject, L. 102, col 7		**404**
405	Return on Capital	#DIV/0!	Line 209		**405**
406	Other Taxes	#DIV/0!	1-BaseTRR, L. 507		**406**
407	Income Taxes	#DIV/0!	Line 303		**407**
408	Revenue Credits	$0	20-RevenueCredits, L.100, col 7 + L. 1002, col 5	Negative Value	**408**
409	NP&S Credit	$0	1-BaseTRR, L. 510	Negative Value	**409**
410	Amortization and Regulatory Debits/Credits	$0	1-BaseTRR, L. 511		**410**
411	**Total without FF, Uncollectibles, and South Georgia**	**#DIV/0!**	Sum Lines 400 to 410		**411**
	Wildfire Self-Insurance				
412	Wildfire Self-Insurance Initial Funding				**412**
413	Wildfire Self-Insurance Replenishment Funding				**413**
414	Total Wildfire Self-Insurance Funding	$0	Line 412 + Line 413		**414**
	SFGR Tax and Franchise Fees				
415	Franchise Fees Factor	#DIV/0!	1-BaseTRR, L. 513		**415**
416	SFGR Tax Factor	#DIV/0!	1-BaseTRR, L. 514		**416**
417	**Total SFGR Tax and Franchise Fees**	**#DIV/0!**	(Line 411 + Line 414) * (Line 415 + Line 416)		**417**

	True-up Transmission Revenue Requirement				**Prior Year: -2**
	Input cells are shaded gold				
418	**Total with SFGR Tax and Franchise Fees**	**#DIV/0!**	Line 411 + Line 414 + Line 417		**418**
	Annual True-up Adjustment				
419	ATA that was included in the Prior Year's Rates				**419**
420	**Total with ATA**	**#DIV/0!**	Line 418 + Line 419		**420**
	Uncollectibles and Retail (South Georgia) Tax Adjustment				
421	Uncollectibles Factor	#DIV/0!	1-BaseTRR, L. 700		**421**
422	Uncollectibles Expense	#DIV/0!	Line 420 * Line 421		**422**
423	Retail (South Georgia) Tax Adjustment	#DIV/0!	23-RetailSGTax, L. 305, col 4		**423**
424	**True-up Transmission Revenue Requirement**	**#DIV/0!**	Line 420 + Line 422 + Line 423	Note 1	**424**

Notes:

1) The True-up Transmission Revenue Requirement calculated in this schedule is only applicable for Prior Year 2024 and after. The True-up Transmission Revenue Requirement for prior year 2022 and 2023 will be calculated in TO20 Model.

...

Schedule 4-ATA
Annual True-up Adjustment — **Rate Year:**
Input cells are shaded gold — **Prior Year: -2**

1) Retail Revenues

Instructions:

1) Populate the table with retail revenue data from the Prior Year.
2) Input the Total Sales from the Prior Year FERC Form 1 on Line 113. The total on Line 112, col 8, should match the total on Line 113.

Line	Month	Col 1 Note 1 Retail Transmission	Col 2 Note 2 Other Transmission	Col 3 Distribution	Col 4 Generation	Col 5 Public Purpose Programs	Col 6 Nuclear Decommissioning	Col 7 Other	Col 8 Sum of Col 1 to 7 Total Revenue	Line
100	Jan								$0	100
101	Feb								$0	101
102	Mar								$0	102
103	Apr								$0	103
104	May								$0	104
105	Jun								$0	105
106	Jul								$0	106
107	Aug								$0	107
108	Sep								$0	108
109	Oct								$0	109
110	Nov								$0	110
111	Dec								$0	111
112	Totals:	$0	$0	$0	$0	$0	$0	$0	**$0**	112
113								**Total Sales: FF1 300-301, L. 10, col b**		113

2) Comparison of Monthly True-Up TRR to Monthly Retail Transmission Revenue

Instructions:

1) Input any corrections or adjustments from previous Annual Update Filings on Line 201. Input the Corrected Principle in Col 5 and the Accumulated Interest in Col 8. A workpaper must accompany any correction or adjustment.
2) Input the FERC interest rates (18 C.F.R. §35.19a) for the corresponding Month and Year into Col 6.

Line	True Up TRR:	Source:	Line
200	#DIV/0!	3-True-up TRR, L. 424	200

Line	Month	Col 1 Year	Col 2 Note 3 Retail Monthly True-up TRR	Col 3 Note 4 Retail Transmission Revenues	Col 4 Col 2 - Col 3 Retail Monthly Excess or Shortfall in Revenue	Col 5 Note 5 Cumulative Excess or Shortfall in Retail Revenue without Interest	Col 6 Note 6 FERC Interest Rate	Col 7 Note 7 Monthly Interest	Col 8 Note 8 Accumulated Interest	Col 9 Col 5 + Col 8 Cumulative Excess or Shortfall in Retail Revenue with Interest	Line
201	December	-3	N/A	N/A	N/A	$0	N/A	N/A	$0	$0	201
202	January	-2	$0	$0	$0	$0		$0	$0	$0	202
203	February	-2	$0	$0	$0	$0		$0	$0	$0	203
204	March	-2	$0	$0	$0	$0		$0	$0	$0	204
205	April	-2	$0	$0	$0	$0		$0	$0	$0	205
206	May	-2	$0	$0	$0	$0		$0	$0	$0	206
207	June	-2	$0	$0	$0	$0		$0	$0	$0	207
208	July	-2	$0	$0	$0	$0		$0	$0	$0	208
209	August	-2	$0	$0	$0	$0		$0	$0	$0	209
210	September	-2	$0	$0	$0	$0		$0	$0	$0	210
211	October	-2	$0	$0	$0	$0		$0	$0	$0	211
212	November	-2	$0	$0	$0	$0		$0	$0	$0	212
213	December	-2	$0	$0	$0	$0		$0	$0	$0	213
214	January	-1	N/A	N/A	$0	$0		$0	$0	$0	214
215	February	-1	N/A	N/A	$0	$0		$0	$0	$0	215
216	March	-1	N/A	N/A	$0	$0		$0	$0	$0	216
217	April	-1	N/A	N/A	$0	$0		$0	$0	$0	217
218	May	-1	N/A	N/A	$0	$0		$0	$0	$0	218
219	June	-1	N/A	N/A	$0	$0		$0	$0	$0	219

Annual True-up Adjustment | **Rate Year:**
Input cells are shaded gold | **Prior Year: -2**

220	July	-1	N/A	N/A	$0	$0		$0	$0	$0	**220**
221	August	-1	N/A	N/A	$0	$0		$0	$0	$0	**221**
222	September	-1	N/A	N/A	$0	$0		$0	$0	$0	**222**
223	October	-1	N/A	N/A	$0	$0		$0	$0	$0	**223**
224	November	-1	N/A	N/A	$0	$0		$0	$0	$0	**224**
225	December	-1	N/A	N/A	$0	$0		$0	$0	$0	**225**
			$0								

3) Amortization of the Balance of the Cumulative Excess or Shortfall in Revenue with Interest Over the Rate Year

Instructions:

1) Input the Total Amortization amount on Line 312 that will set the December Month Ending Balance on Line 311, Col 7 equal to $0. (Hint: Use the Goal Seek Function to set the December Month Ending Balance in Col 7 to equal $0)

Line	Month	Col 1 Year	Col 2 Note 9 Month Beginning Balance	Col 3 Amortization	Col 4 Col 2 + Col 3 Month Ending Balance without Interest	Col 5 Note 10 Interest for Current Month	Col 6 Note 11 FERC Interest Rate	Col 7 Col 4 + Col 5 Month Ending Balance		Line
300	January	0	$0	$0	$0	$0	0.00%	$0		**300**
301	February	0	$0	$0	$0	$0	0.00%	$0		**301**
302	March	0	$0	$0	$0	$0	0.00%	$0		**302**
303	April	0	$0	$0	$0	$0	0.00%	$0		**303**
304	May	0	$0	$0	$0	$0	0.00%	$0		**304**
305	June	0	$0	$0	$0	$0	0.00%	$0		**305**
306	July	0	$0	$0	$0	$0	0.00%	$0		**306**
307	August	0	$0	$0	$0	$0	0.00%	$0		**307**
308	September	0	$0	$0	$0	$0	0.00%	$0		**308**
309	October	0	$0	$0	$0	$0	0.00%	$0		**309**
310	November	0	$0	$0	$0	$0	0.00%	$0		**310**
311	December	0	$0	$0	$0	$0	0.00%	$0	Goal Seek has been run.	**311**
312			**Total Amortization:**							**312**

4) Annual True-up Adjustment

Line	ATA for Prior Year 2024 and After	Source		Line
400	$0	Negative Line 312, Col 3		**400**
401	$0		Note 14	**401**
402	$0	Line 400 + Line 401		**402**

Line	ATA for Prior Year 2022 and 2023 from TO20 Model	Source		Line
403			Note 15	**403**

Line	ATA	Source	Line
404	$0	Line 403 if PY is 2022 or 2023, Line 402 if PY is 2024 and after.	**404**

5) Partial Year True-up and TRR Allocation Factors

Instructions:

1) On Line 500, Input 'No' for a Full Year True-up, otherwise Input 'Yes' for a Partial Year True-up

2) If Line 500 is 'Yes', Input 'Yes' or 'No' in Col 4 for each month that the Formula Rate was in effect in the Prior Year and Input the True-up TRR Allocation Factors into Col 2.

Line			Line
500	**Partial Year True-up?**		**500**

Line	Month	Col 1 Prior Year	Col 2 Note 12 True-up TRR Allocation Factor	Col 3 Note 13 PG&E Gross Load (MWh)	Col 4 Formula Rate Effective?	Line
501	January	-2	#DIV/0!			**501**
502	February	-2	#DIV/0!			**502**

Annual True-up Adjustment **Rate Year:**
Input cells are shaded gold **Prior Year: -2**

503	March	-2	#DIV/0!		**503**
504	April	-2	#DIV/0!		**504**
505	May	-2	#DIV/0!		**505**
506	June	-2	#DIV/0!		**506**
507	July	-2	#DIV/0!		**507**
508	August	-2	#DIV/0!		**508**
509	September	-2	#DIV/0!		**509**
510	October	-2	#DIV/0!		**510**
511	November	-2	#DIV/0!		**511**
512	December	-2	#DIV/0!		**512**
513	**Total**		**#DIV/0!**	0	**513**

6) Final True-up Adjustment

Instructions:

1) PG&E shall calculate the Final True-up Adjustment for the period spanning the day after the period covered by the most recent ATA that was included in the Base TRR to the expiration of the Formula Rate.
2) The Final True Up Adjustment shall be calculated using the same methodology as above, with interest through the date of the termination of the Formula Rate.

Notes:

1) Data for cols 1 through 7 are Prior Year revenues from PG&E's Revenue Reporting System, Report R646BRESU. Col 1 only includes Base Retail Transmission Revenues. Any other retail transmission revenues are included in the "Other" Category.
2) Other Transmission Revenues includes: the Transmission Revenue Balancing Account Adjustment (TRBAA) revenues, the Reliability Services Balancing Account Adjustment (RSBAA) revenues, the End-use Customer Refund Balancing Account Adjustment (ECRBAA) revenues, and the Transmission Access Charge Balancing Account Adjustment (TACBAA) revenues.
3) For each month of the Prior Year, the Monthly True-up TRR is calculated by multiplying the True-up TRR on Line 200 by monthly allocation factors from Lines 501 to 512, Col 2.

4) The Retail Transmission Revenues are from Lines 100 to 111, Col 1. For a partial year true-up, only revenues for the months that the Formula Rate was in effect in the Prior Year are included.
5) Corrections or Adjustments applied to Line 201 from previously-filed Annual Updates are outlined in Section 4.7.6 of the Protocols.
6) The FERC interest rate as stated in Instruction 2.
7) Monthly Interest is calculated by summing half of the current month's "Excess or Shortfall in Revenue" with last month's "Cumulative Excess or Shortfall in Revenue with Interest" and multiplying by one-twelve (1/12) of the current month's FERC annual interest rate.
8) Accumulated Interest is the sum of the current month's "Monthly Interest" with last month's "Accumulated Interest".
9) The January 'Month Beginning Balance' on Line 300, Col 2 is equal to the 'Cumulative Excess or Shortall in Revenue with Interest' from Line 225, Col 9.

10) 'Interest for the Current Month' (Col 5) is based on the average of the 'Month Beginning Balance' (Col 2) and the 'Month Ending Balancing without Interest' (Col 4), multiplied by one-twelve of the 'FERC Interest Rate' (Col 6).
11) The 'FERC Interest Rate' is the last known FERC interest rate from Line 225, Col 6.
12) To calculate the monthly allocation factor, take the corresponding month's Gross Load in Col 3 and divide by the total Gross Load in L. 513, Col 3.
13) Data is PG&E's monthly Gross Load as measured by the CASIO monthly settlements of PG&E's Gross Load.
14) Line 401 is to record the ATA for Prior Year 2024 for the period TO21 is not in effect for TO21 RY2026 Annual Update. The value should be zero for Prior Year 2025 and thereafter.
15) Line 403 is to record the ATA for Prior Year 2022 and 2023 to be trued up in Rate Year 2024 and 2025 which are calculated through TO20-RY2024 and TO20-RY2025 Annual Update.

...

Schedule 5-CostofCap-1

Calculation of Components of Cost of Capital Rate **Prior Year: -2**

Input cells are shaded gold

1) Return and Capitalization Calculations

Line	Description	Values	Source	Notes	Line
	Calculation of Long Term Debt Amount				
100	Bonds -- Account 221		WP 5-CostofCap, L 100, col 1	13-month average	**100**
101	(Less) Reacquired Bonds (Acct. 222)		WP 5-CostofCap, L 200, col 1	13-month average, enter negative	**101**
102	(Plus) Other Long-Term Debt (Acct. 224)		WP 5-CostofCap, L 300, col 1	13-month average	**102**
103	**Long Term Debt Amount**	**$0**	Sum of Lines 100 to 102		**103**
	Calculation of Preferred Stock Amount				
104	Preferred Stock Amount -- Account 204		WP 5-CostofCap, L 800, col 1	13-month average	**104**
105	Unamortized Issuance Costs		WP 5-CostofCap, L 900, col 1	13-month average	**105**
106	Net Gain (Loss) From Purchase and Tender Offers		WP 5-CostofCap, L 1000, col 1	13-month average	**106**
107	**Preferred Stock Amount**	**$0**	Sum of Lines 104 to 106		**107**
	Calculation of Common Stock Equity Amount				
108	Total Proprietary Capital		WP 5-CostofCap, L 1300, col 1	13-month average	**108**
109	Less Preferred Stock Amount	$0	Line 107	Same as Line 107, but negative	**109**
110	Less Unappropriated Undist. Sub. Earnings -- Acct. 216.1		WP 5-CostofCap, L 1100, col 1	13-month average, reverse sign	**110**
111	Less Accumulated Other Comprehensive Income -- Account 219		WP 5-CostofCap, L 1200, col 1	13-month average, reverse sign	**111**
112	**Common Stock Equity Amount**	**$0**	Sum of Lines 108 to 111		**112**
113	**Equity Ratio**	**#DIV/0!**	Line 112 ÷ (Line 103 + Line 107 + Line 112)		**113**

Notes:

...

Schedule 5-CostofCap-2
Long Term Debt Cost Percentage **Prior Year: -2**
Input cells are shaded gold

1) Calculation of Cost of Long Term Debt

Line	Description	Values	Source	Notes	Line
	Long-Term Debt Component - Denominator:				
100	(Plus) Bonds (Acct. 221)		WP 5-CostofCap, L 100, col 1	13-month Average	**100**
101	(Less) Reacquired Bonds (Acct. 222)		WP 5-CostofCap, L 200, col 1	13-month Average	**101**
102	(Plus) Other Long-Term Debt (Acct. 224)		WP 5-CostofCap, L 300, col 1	13-month Average	**102**
103	(Plus) Unamortized Premium on Long-Term Debt (Acct. 225)		WP 5-CostofCap, L 400, col 1	13-month Average	**103**
104	(Less) Unamortized Discount on Long-Term Debt-Debit (Acct. 226)		WP 5-CostofCap, L 500, col 1	13-month Average	**104**
105	(Less) Unamortized Debt Expenses (Acct. 181)		WP 5-CostofCap, L 600, col 1	13-month Average	**105**
106	(Less) Unamortized Loss on Reacquired Debt (Acct. 189)		WP 5-CostofCap, L 700, col 1	13-month Average	**106**
107	**LTD = Long Term Debt**	**$0**	Lines ((100 + 102 + 103) - (101 + 104 + 105 + 106))	13-month Average	**107**
	Long-Term Debt Component - Numerator:				
108	(Plus) Interest on Long-Term Debt (Acct. 427)		WP 5-CostofCap, L 1400, col 1	Year-To-Date	**108**
109	(Plus) Amort. of Debt Disc. and Expense (Acct. 428)		WP 5-CostofCap, L 1500, col 1	Year-To-Date	**109**
110	(Plus) Amortization of Loss on Reacquired Debt (Acct. 428.1)		WP 5-CostofCap, L 1600, col 1	Year-To-Date	**110**
111	(Less) Amort. of Premium on Debt-Credit (Acct. 429)		WP 5-CostofCap, L 1700, col 1	Year-To-Date	**111**
112	(Less) Amortization of Gain on Reacquired Debt-Credit (Acct. 429.1)		WP 5-CostofCap, L 1800, col 1	Year-To-Date	**112**
113	**LTD interest**	**$0**	Lines ((108 + 109 + 110) - (111 + 112))		**113**
114	**Cost of Long-Term Debt:**	**#DIV/0!**	Line 113 / Line 107		**114**

Notes:
...

Schedule 5-CostofCap-3
Preferred Stock Cost Percentage — **Prior Year: -2**
Input cells are shaded gold

1) Calculation of "Preferred Stock Cost Percentage"

Line	Description	Amount	Reference	Line
100	Total Annual Cost of Preferred Stock:	$0	Line 208, Col 9	100
101	Total Reacquired Preferred Stock Cost:	$0	Line 305, Col 6	101
102	**Total Annual Cost of Preferred:**	**$0**	Line 100 + Line 101	102
103	Total Preferred Stock Amount Outstanding:	$0	Line 208, Col 5	103
104	Total Premium/Discount	$0	Line 208, Col 6	104
105	**Total Preferred Balance:**	**$0**	Line 103 + Line 104	105
106	**Preferred Stock Cost Percentage:**	**#DIV/0!**	Line 102 / Line 105	106

2) Preferred Stock Information for each Outstanding Series

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	
	PG&E Records Note 1	PG&E Records Note 1	FF1 250-251, col a	PG&E Records Note 1	FF1 250-251, col f	PG&E Records Note 1	FF1 250-251, col e	= Col 5 + Col 6	= Col 4 x Col 7 Note 2	
Line	**Preferred Stock Series Name**	**Issue Date**	**Dividend Rate**	**Dividend**	**Face Value/ Amount Outstanding**	**Total Premium/ Discount Cost**	**Shares Outstanding**	**Net Proceeds at Issuance**	**Annual Dividend**	**Line**
200								$0	$0	200
201								$0	$0	201
202								$0	$0	202
203								$0	$0	203
204								$0	$0	204
205								$0	$0	205
206								$0	$0	206
207								$0	$0	207
208	**Total Amount Outstanding (sum of above):**				**$0**	**$0**	**0**	**$0**	**$0**	208

3) Reacquired Preferred Stock Information

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6		
Line	**Preferred Stock**	**Call Date**	**Total Issuance Cost**	**Unamortized Issuance Cost**	**Amortization Period**	**Issuance Amortization Cost**	**Notes and Sources**	**Line**
300								300
301								301
302								302
303								303
304	---							304
305	**Total Annual Cost (sum of above):**			$ -		$ -		305

Notes:
1) PG&E's Treasury uses an internal monthly Excel-based report to track historical information associated with preferred stock issuances. Due to the age of each preferred stock series, many of the original hard copy records are no longer available, and electronic records were not available at time of issuance.
2) Annual dividend calculation consistent with 18 CFR 35.13 (22) (iii)
...

Schedule 6-PlantJursidiction

Transmission Plant Jurisdiction **Prior Year: -2**

Input cells are shaded gold

Transmission Plant in FERC Form 1 for Prior Year:

Transmission Plant balances are Prior Year ending balances from PG&E's FERC Form 1.

FERC Transmission Plant represents only Network Transmission plant that is eligible for inclusion in rate base and recoverable through the TO rate case.

CPUC Transmission Plant represents Transmission Plant not recoverable through the TO rate case.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	
					Note 1			Col 1 + Col 3 - Col 4	
			FERC Form 1			FERC		CPUC	
Line	FERC Account	Account Description	Transmission Plant	Source for Col 1	Adjustments	Transmission Plant	Source for Col 4	Transmission Plant	Line
100	350	Land and Land Rights		FF1 204-207, L. 48, col g		$0	7-PlantInService, L. 112, col 1 + col 2	$0	**100**
101	352	Structures and Improvements		FF1 204-207, L. 49, col g		$0	7-PlantInService, L. 112, col 3 + col 4	$0	**101**
102	353	Station Equipment		FF1 204-207, L. 50, col g		$0	7-PlantInService, L. 112, col 5 + col 6	$0	**102**
103	354	Towers and Fixtures		FF1 204-207, L. 51, col g		$0	7-PlantInService, L. 112, col 7	$0	**103**
104	355	Poles and Fixtures		FF1 204-207, L. 52, col g		$0	7-PlantInService, L. 112, col 8	$0	**104**
105	356	Overhead Conductors and Devices		FF1 204-207, L. 53, col g		$0	7-PlantInService, L. 112, col 9	$0	**105**
106	357	Underground Conduit		FF1 204-207, L. 54, col g		$0	7-PlantInService, L. 112, col 10	$0	**106**
107	358	Underground Conductor and Devices		FF1 204-207, L. 55, col g		$0	7-PlantInService, L. 112, col 11	$0	**107**
108	359	Roads and Trails		FF1 204-207, L. 56, col g		$0	7-PlantInService, L. 112, col 12	$0	**108**
109	359.1	Asset Retirement Costs for Transmission Plant		FF1 204-207, L. 57, col g		$0	Note 2	$0	**109**
110		**Total Transmission Plant**	**$0**		**$0**	**$0**		**$0**	**110**

Notes:

...

Schedule 7-PlantInService
Network Transmission Plant In Service **Prior Year: -2**
Input cells are shaded gold

1) Total Network Transmission Functional Plant

Total Network Transmission Functional Plant is the total of High Voltage (Section 2) and Low Voltage (Section 3) Network Transmission Plant. The monthly balances in Lines 100 -112 are the end-of-month balances for Prior Year and December of Prior Year minus 1.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13		
			Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Total of Col 1-12		
		FERC Account:	**350.01**	**350.02**	**352.01**	**352.02**	**353.01**	**353.02**	**354**	**355**	**356**	**357**	**358**	**359**			
Line	**Month**	**Year**	**ETP35001**	**ETP35002**	**ETP35201**	**ETP35202**	**ETP35301**	**ETP35302**	**ETP35400**	**ETP35500**	**ETP35600**	**ETP35700**	**ETP35800**	**ETP35900**	**Total**	**Source**	**Line**
100	December	-3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 200 + Line 300	**100**
101	January	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 201 + Line 301	**101**
102	February	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 202 + Line 302	**102**
103	March	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 203 + Line 303	**103**
104	April	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 204 + Line 304	**104**
105	May	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 205 + Line 305	**105**
106	June	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 206 + Line 306	**106**
107	July	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 207 + Line 307	**107**
108	August	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 208 + Line 308	**108**
109	September	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 209 + Line 309	**109**
110	October	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 210 + Line 310	**110**
111	November	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 211 + Line 311	**111**
112	December	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 212 + Line 312	**112**
113	**13-Month Average**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		**113**

2) Network Transmission Functional Plant - High Voltage

Network Transmission High Voltage Functional Plant balances are extracted from PowerPlan, PG&E's fixed asset system of record, by querying by Asset Class, FERC Account and UCC. The balances are then adjusted to include only the FERC Jurisdiction Transmission plant that is eligible for inclusion in rate base, and recoverable through the TO rate case (as shown in WP_7-PlantInService 1). The monthly balances in Lines 200 - 212 are the end-of-month balances for Prior Year and December of Prior Year minus 1.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	
															Total of Col 1-12	
		FERC Account:	**350.01**	**350.02**	**352.01**	**352.02**	**353.01**	**353.02**	**354**	**355**	**356**	**357**	**358**	**359**		
Line	**Month**	**Year**	**ETP35001**	**ETP35002**	**ETP35201**	**ETP35202**	**ETP35301**	**ETP35302**	**ETP35400**	**ETP35500**	**ETP35600**	**ETP35700**	**ETP35800**	**ETP35900**	**Total**	**Line**
200	December	-3													$0	**200**
201	January	-2													$0	**201**
202	February	-2													$0	**202**
203	March	-2													$0	**203**
204	April	-2													$0	**204**
205	May	-2													$0	**205**
206	June	-2													$0	**206**
207	July	-2													$0	**207**
208	August	-2													$0	**208**
209	September	-2													$0	**209**
210	October	-2													$0	**210**
211	November	-2													$0	**211**
212	December	-2													$0	**212**
213	**13-Month Average**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**213**

Network Transmission Plant In Service | **Prior Year: -2**

Input cells are shaded gold

3) Network Transmission Functional Plant - Low Voltage

Network Transmission Low Voltage Functional Plant balances are extracted from PowerPlan, PG&E's fixed asset system of record, by querying by Asset Class, FERC Account and UCC. The balances are then adjusted to include only the FERC Jurisdiction Transmission plant that is eligible for inclusion in rate base, and recoverable through the TO rate case (as shown in WP_7-PlantInService 1). The monthly balances in Lines 300 - 312 are the end-of-month balances for Prior Year and December of Prior Year minus 1.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13 Total of Col 1-12	
		FERC Account:	350.01	350.02	352.01	352.02	353.01	353.02	354	355	356	357	358	359		
Line	**Month**	**Year**	**ETP35001**	**ETP35002**	**ETP35201**	**ETP35202**	**ETP35301**	**ETP35302**	**ETP35400**	**ETP35500**	**ETP35600**	**ETP35700**	**ETP35800**	**ETP35900**	**Total**	**Line**
300	December	-3													$0	300
301	January	-2													$0	301
302	February	-2													$0	302
303	March	-2													$0	303
304	April	-2													$0	304
305	May	-2													$0	305
306	June	-2													$0	306
307	July	-2													$0	307
308	August	-2													$0	308
309	September	-2													$0	309
310	October	-2													$0	310
311	November	-2													$0	311
312	December	-2													$0	312
313	**13-Month Average**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**313**

4) Network Transmission Common, General and Intangible (CGI) Plant

Network Transmission Common, General and Intangible (CGI) Plant is the portion of total PG&E CGI Plant allocated to Network Transmission using O&M labor allocation factors.

			Col 1	Col 2 24-Allocators, L. 113	Col 3 Col 1 * Col 2	Col 4 Col 3 * 24-Allocators, L. 126	Col 5 Col 3 * 24-Allocators, L. 127		
Line	**Month**	**Year**	**Total PG&E CGI Plant**	**Network Transmission Labor Factor (Total Company)**	**Total Network Transmission CGI Plant**	**Total High Voltage CGI Plant**	**Total Low Voltage CGI Plant**	**Source**	**Line**
400	December	-3		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	See WP_7-PlantInService 5, L. 122, col 14 (or col 10) from annual update for Prior Year minus 1	400
401	December	-2		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	See WP_7-PlantInService 5, L. 122, col 10	401
402	**Average**		**#DIV/0!**		**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	(Line 400 + Line 401)/2	**402**

Notes:

...

Schedule 8-AbandonedProject

Significant Abandoned or Cancelled Projects Balance and Amortization **Prior Year: -2**

Input cells are shaded gold

PG&E will include recoverable costs in this Schedule for significant abandoned or cancelled projects approved or pending approval by the Commission for rate base recovery.

1) Prior Year Abandoned or Cancelled Projects

Line		Col 1 Voltage	Col 2 Total Project Costs	Col 3 Recoverable Costs	Col 4 Amortization Period (yrs)	Col 5 Start of Amortization	Col 6 BOY Balance	Col 7 Prior Year Amortization	Col 8 EOY Balance	Col 9 (Col 6 + Col 8)/2 Average Balance	Col 10 Col 9 * Composite Tax Rate ADIT	Col 11 Col 8 - Col 10 EOY Balance Net of ADIT	Col 12 Col 9 - Col 10 Average Balance Net of ADIT	Col 13 FERC Docket Number	Col 14 Authorization Status	Line
100	Total High Voltage Abandoned or Cancelled Projects (sum from below)	High	$0	$0			$0	$0	$0	$0	$0	$0	$0			100
101	Total Low Voltage Abandoned or Cancelled Projects (sum from below)	Low	$0	$0			$0	$0	$0	$0	$0	$0	$0			101
102	Totals			$0			$0	$0	$0	$0	$0	$0	$0			102
103										$0	$0	$0	$0			103
104	…									$0	$0	$0	$0			104

Notes:

…

Schedule 9-PlantAdditions

Forecast Net Plant Additions for Network Transmission Plant **Prior Year: -2**

Input cells are shaded gold

Forecast Network Transmission Net Plant Additions balances are calculated using the forecast capital expenditures for Functional Plant major work categories for the two calendar years after the Prior Year.
The 13-month average (including Prior Year + 2 and December of Prior Year + 1) of Net Plant Additions balances is multiplied by the AFCR to calculate the ITRR.

1) Total Forecast Net Plant Additions

Total Forecast Net Plant Additions are the total of High Voltage Net Plant Additions (Section 2) and Low Voltage Net Plant Additions (Section 3).

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	
			Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	
	Forecast Period		Gross	Incremental	Depreciation	Cost of Removal	Incremental	Net	
Line	Month	Year	Plant Adds	Gross Plant	Accrual	Spend	Reserve	Plant Additions	Line
100	January	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	100
101	February	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	101
102	March	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	102
103	April	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	103
104	May	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	104
105	June	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	105
106	July	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	106
107	August	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	107
108	September	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	108
109	October	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	109
110	November	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	110
111	December	-1	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	111
112	January	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	112
113	February	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	113
114	March	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	114
115	April	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	115
116	May	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	116
117	June	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	117
118	July	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	118
119	August	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	119
120	September	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	120
121	October	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	121
122	November	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	122
123	December	0	$0	$0	#DIV/0!	$0	#DIV/0!	#DIV/0!	123
124	**13-Month Average (Sum Lines 111 to 123)/13:**			**$0**				**#DIV/0!**	124
125	**Rate Year Depr Exp (Sum Jan - Dec of the Rate Year)**				**#DIV/0!**				125

2) High Voltage Net Plant Additions

High Voltage Net Plant Additions is the total of the forecasted Incremental Gross Plant less the Incremental Reserve. Incremental Gross Plant is the total of forecast Gross Plant Additions.
Incremental Reserve is the cumulative total of the calculated depreciation accruals related to the Incremental Gross Plant less the forecast Cost of Removal Spend.
For the calculation of forecast Gross Plant Additions and Cost of Removal Spend by planning order, see workpaper WP_9-PlantAdditions 1-4.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	
			Note 1	Prior Month + Col 1	Col 2 * (12-DepRates, L. 110, col 9)/12 Note 3	Note 2	Prior Month + Col 3 - Col 4	Col 2 - Col 5	
	Forecast Period		Gross	Incremental	Depreciation	Cost of Removal	Incremental	Net	
Line	Month	Year	Plant Additions	Gross Plant	Accrual	Spend	Reserve	Plant Additions	Line

Forecast Net Plant Additions for Network Transmission Plant **Prior Year: -2**

Input cells are shaded gold

Forecast Network Transmission Net Plant Additions balances are calculated using the forecast capital expenditures for Functional Plant major work categories for the two calendar years after the Prior Year.
The 13-month average (including Prior Year + 2 and December of Prior Year + 1) of Net Plant Additions balances is multiplied by the AFCR to calculate the ITRR.

200	January	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**200**
201	February	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**201**
202	March	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**202**
203	April	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**203**
204	May	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**204**
205	June	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**205**
206	July	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**206**
207	August	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**207**
208	September	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**208**
209	October	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**209**
210	November	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**210**
211	December	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	**211**
212	January	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**212**
213	February	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**213**
214	March	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**214**
215	April	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**215**
216	May	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**216**
217	June	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**217**
218	July	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**218**
219	August	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**219**
220	September	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**220**
221	October	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**221**
222	November	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**222**
223	December	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	**223**
224		**13-Month Average:**		**$0**				**#DIV/0!**	**224**

Forecast Net Plant Additions for Network Transmission Plant **Prior Year: -2**

Input cells are shaded gold

Forecast Network Transmission Net Plant Additions balances are calculated using the forecast capital expenditures for Functional Plant major work categories for the two calendar years after the Prior Year.
The 13-month average (including Prior Year + 2 and December of Prior Year + 1) of Net Plant Additions balances is multiplied by the AFCR to calculate the ITRR.

3) Low Voltage Net Plant Additions

Low Voltage Net Plant Additions are the total of the forecasted Incremental Gross Plant less the Incremental Reserve. Incremental Gross Plant is the total of forecast Gross Plant Additions.
Incremental Reserve is the total of the calculated depreciation accruals related to the Incremental Gross Plant less the forecast Cost of Removal Spend.
For the calculation of forecast Gross Plant Additions and Cost of Removal by planning order, see workpaper WP_9-PlantAdditions 1-4.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	
			Note 1	Prior Month + Col 1	Col 2 * (12-DepRates, L. 110, col 9)/12 Note 3	Note 2	Prior Month + Col 3 - Col 4	Col 2 - Col 5	
	Forecast Period		Gross	Incremental	Depreciation	Cost of Removal	Incremental	Net	
Line	Month	Year	Plant Additions	Gross Plant	Accrual	Spend	Reserve	Plant Additions	Line
300	January	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	300
301	February	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	301
302	March	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	302
303	April	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	303
304	May	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	304
305	June	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	305
306	July	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	306
307	August	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	307
308	September	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	308
309	October	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	309
310	November	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	310
311	December	-1		$0	#DIV/0!		#DIV/0!	#DIV/0!	311
312	January	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	312
313	February	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	313
314	March	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	314
315	April	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	315
316	May	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	316
317	June	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	317
318	July	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	318
319	August	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	319
320	September	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	320
321	October	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	321
322	November	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	322
323	December	0		$0	#DIV/0!		#DIV/0!	#DIV/0!	323
324		**13-Month Average:**		**$0**				**#DIV/0!**	**324**

Notes:

...

Schedule 10-AccDep

Accumulated Depreciation for Network Transmission Assets **Prior Year: -2**

Input cells are shaded gold

1) Total Accumulated Depreciation for Network Transmission Functional Plant

Total Accumulated Depreciation for Network Transmission Functional Plant is the total of the Accumulated Depreciation related to High Voltage (Section 2) and Low Voltage (Section 3) Network Transmission Plant.
The monthly balances in Lines 100 -112 are the end-of-month balances for Prior Year and December of Prior Year - 1.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13		
			Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Section 2 + Section 3	Total of Col 1-12		
		FERC Account:	**350.01**	**350.02**	**352.01**	**352.02**	**353.01**	**353.02**	**354**	**355**	**356**	**357**	**358**	**359**			
Line	**Month**	**Year**	**ETP35001**	**ETP35002**	**ETP35201**	**ETP35202**	**ETP35301**	**ETP35302**	**ETP35400**	**ETP35500**	**ETP35600**	**ETP35700**	**ETP35800**	**ETP35900**	**Total**	**Source**	**Line**
100	December	-3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 200 + Line 300	**100**
101	January	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 201 + Line 301	**101**
102	February	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 202 + Line 302	**102**
103	March	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 203 + Line 303	**103**
104	April	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 204 + Line 304	**104**
105	May	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 205 + Line 305	**105**
106	June	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 206 + Line 306	**106**
107	July	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 207 + Line 307	**107**
108	August	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 208 + Line 308	**108**
109	September	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 209 + Line 309	**109**
110	October	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 210 + Line 310	**110**
111	November	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 211 + Line 311	**111**
112	December	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Line 212 + Line 312	**112**
113	**13-Month Average**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		**113**

2) Accumulated Depreciation for Network Transmission Functional Plant - High Voltage

Accumulated Depreciation balances for Network Transmission High Voltage Functional Plant are extracted from PowerPlan, PG&E's fixed asset system of record, by querying by Asset Class, FERC Account and UCC. The balances are then adjusted to include only the amounts related to FERC Jurisdiction Transmission Plant that are eligible for inclusion in rate base and recoverable through the TO rate case. The monthly balances in Lines 200 - 212 are the end-of-month balances for Prior Year and December of Prior Year minus 1.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	
															Total of Col 1-12	
		FERC Account:	**350.01**	**350.02**	**352.01**	**352.02**	**353.01**	**353.02**	**354**	**355**	**356**	**357**	**358**	**359**		
Line	**Month**	**Year**	**ETP35001**	**ETP35002**	**ETP35201**	**ETP35202**	**ETP35301**	**ETP35302**	**ETP35400**	**ETP35500**	**ETP35600**	**ETP35700**	**ETP35800**	**ETP35900**	**Total**	**Line**
200	December	-3													$ -	**200**
201	January	-2													$ -	**201**
202	February	-2													$ -	**202**
203	March	-2													$ -	**203**
204	April	-2													$ -	**204**
205	May	-2													$ -	**205**
206	June	-2													$ -	**206**
207	July	-2													$ -	**207**
208	August	-2													$ -	**208**
209	September	-2													$ -	**209**
210	October	-2													$ -	**210**
211	November	-2													$ -	**211**
212	December	-2													$ -	**212**
213	**13-Month Average**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$ -**	**213**

Accumulated Depreciation for Network Transmission Assets **Prior Year: -2**

Input cells are shaded gold

3) Accumulated Depreciation for Network Transmission Functional Plant - Low Voltage

Accumulated Depreciation balances for Network Transmission Low Voltage Functional Plant are extracted from PowerPlan, PG&E's fixed asset system of record, by querying by Asset Class, FERC Account and UCC. The balances are then adjusted to include only the amounts related to FERC Jurisdiction Transmission Plant that are eligible for inclusion in rate base and recoverable through the TO rate case. The monthly balances in Lines 300 - 312 are the end-of-month balances for Prior Year and December of Prior Year minus 1.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	
															Total of Col 1-12	
		FERC Account:	350.01	350.02	352.01	352.02	353.01	353.02	354	355	356	357	358	359		
Line	Month	Year	ETP35001	ETP35002	ETP35201	ETP35202	ETP35301	ETP35302	ETP35400	ETP35500	ETP35600	ETP35700	ETP35800	ETP35900	Total	Line
300	December	-3													$0	300
301	January	-2													$0	301
302	February	-2													$0	302
303	March	-2													$0	303
304	April	-2													$0	304
305	May	-2													$0	305
306	June	-2													$0	306
307	July	-2													$0	307
308	August	-2													$0	308
309	September	-2													$0	309
310	October	-2													$0	310
311	November	-2													$0	311
312	December	-2													$0	312
313	**13-Month Average**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	313

4) Accumulated Depreciation for Network Transmission Common, General and Intangible (CGI) Plant

Accumulated Depreciation balances for Network Transmission CGI Plant is the portion of total PG&E CGI Plant allocated to Network Transmission using O&M labor allocation factors.

			Col 1	Col 2	Col 3	Col 4	Col 5		
				24-Allocators, L. 113	Col 1 * Col 2	Col 3 * 24-Allocators, L. 126	Col 3 * 24-Allocators, L. 127		
Line	Month	Year	Total PG&E CGI Accumulated Depreciation	Network Transmission Labor Factor (Total Company)	Total Network Transmission CGI Accumulated Depreciation	Total High Voltage CGI Accumulated Depreciation	Total Low Voltage CGI Accumulated Depreciation	Source	Line
400	December	-3		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	See WP_10-AccDep 4, L. 122, col 14 (or col 10) from annual update for Prior Year minus 1	400
401	December	-2		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	See WP_10-AccDep 4, L. 122, col 10	401
402	**Average**		**#DIV/0!**		**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	(Line 400 + Line 401)/2	402

Notes:

...

Schedule 11-Depreciation
Network Transmission Depreciation Expense **Prior Year: -2**
Input cells are shaded gold

1) Depreciation Expense for Network Transmission Functional Plant

Prior Year recorded Depreciation Expense is extracted from PowerPlan, PG&E's fixed asset system of record, by querying by Asset Class. It is then allocated to UCC and Functional Area based on Prior Year ending plant balances.
The Depreciation Expense amounts by FERC Account and Asset Class in Lines 100 and 101 represent the amounts related to High Voltage and Low Voltage Network Transmission Plant.

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	
														Total of Col 1-12	
	FERC Account:	350.01	350.02	352.01	352.02	353.01	353.02	354	355	356	357	358	359		
Line	Voltage	ETP35001	ETP35002	ETP35201	ETP35202	ETP35301	ETP35302	ETP35400	ETP35500	ETP35600	ETP35700	ETP35800	ETP35900	Total	Line
100	High Voltage													$0	100
101	Low Voltage													$0	101
102	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	102

2) Depreciation Expense for Network Transmission Common, General and Intangible (CGI) Plant

Depreciation Expense for Network Transmission CGI Plant is the portion of total PG&E CGI Plant allocated to Network Transmission using O&M labor allocation factors.

		Col 1	Col 2	Col 3	Col 4	Col 5	
		Note 1	24-Allocators, L. 113	Col 1 * Col 2	Col 3 * 24-Allocators, L. 126	Col 3 * 24-Allocators, L. 127	
Line	Year	Total PG&E CGI Depreciation Expense	Network Transmission Labor Factor (Total Company)	Total Network Transmission CGI Depreciation Expense	Total High Voltage CGI Depreciation Expense	Total Low Voltage CGI Depreciation Expense	Line
200	-2		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	200

Calculation of the Depreciation Expense Rate Adjustment

The following sections (Sections 3-6) are used to calculate the Depreciation Expense Rate Adjustment, which is a method to account for the potential difference in the Base TRR that would result from changing the depreciation rates for Network Transmission Functional Plant.
The Depreciation Expense Rate Adjustment factors into the Base TRR in filings where there are proposed depreciation rates for the rate year that are different from the rates used to record depreciation expense in the Prior Year.
It is also included in 1-BaseTRR for each annual update to account for (i.e., remove) any journal entries not derived from the same period's ending Plant balance and authorized depreciation rates.

Network Transmission Depreciation Expense **Prior Year: -2**

Input cells are shaded gold

3) Total Network Transmission Functional Plant

Total Network Transmission Functional Plant Prior Year balances are from 7-PlantInService, L. 101-112.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	
			7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	7-PlantInService	Total of Col 1-12	
		FERC Account:	**350.01**	**350.02**	**352.01**	**352.02**	**353.01**	**353.02**	**354**	**355**	**356**	**357**	**358**	**359**		
Line	**Month**	**Year**	**ETP35001**	**ETP35002**	**ETP35201**	**ETP35202**	**ETP35301**	**ETP35302**	**ETP35400**	**ETP35500**	**ETP35600**	**ETP35700**	**ETP35800**	**ETP35900**	**Total**	**Line**
300	January	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**300**
301	February	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**301**
302	March	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**302**
303	April	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**303**
304	May	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**304**
305	June	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**305**
306	July	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**306**
307	August	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**307**
308	September	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**308**
309	October	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**309**
310	November	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**310**
311	December	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**311**

4) Proposed Network Transmission Functional Plant Depreciation Rates

Proposed Network Transmission Functional Plant Depreciation Rates are from 12-DepRates. The Depreciation Rates for Columns 3-12 are from 12-DepRates, L. 100 - 109.
The rates listed below are annual rates.

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	
		Note 2	Note 3	12-DepRates, L. 100	12-DepRates, L. 101	12-DepRates, L. 102	12-DepRates, L. 103	12-DepRates, L. 104	12-DepRates, L. 105	12-DepRates, L. 106	12-DepRates, L. 107	12-DepRates, L. 108	12-DepRates, L. 109	
Line		**ETP35001**	**ETP35002**	**ETP35201**	**ETP35202**	**ETP35301**	**ETP35302**	**ETP35400**	**ETP35500**	**ETP35600**	**ETP35700**	**ETP35800**	**ETP35900**	**Line**
400	Proposed Depreciation Rates	0.00%	1.84%	1.63%	1.70%	3.63%	1.75%	2.91%	3.24%	3.43%	1.53%	1.99%	1.90%	**400**

5) Calculated Depreciation Expense for Prior Year Recorded Network Transmission Functional Plant Using Proposed Rates

The Prior Year recorded plant balances are multiplied by the proposed depreciation rates to calculate the total Prior Year depreciation expense that would have resulted from using the proposed rates.

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	
			Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Section 3 * (Section 4)/12	Total of Col 1-12	
	FERC Account:		**350.01**	**350.02**	**352.01**	**352.02**	**353.01**	**353.02**	**354**	**355**	**356**	**357**	**358**	**359**		
Line	**Month**	**Year**	**ETP35001**	**ETP35002**	**ETP35201**	**ETP35202**	**ETP35301**	**ETP35302**	**ETP35400**	**ETP35500**	**ETP35600**	**ETP35700**	**ETP35800**	**ETP35900**	**Total**	**Line**
500	January	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**500**
501	February	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**501**
502	March	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**502**
503	April	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**503**
504	May	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**504**
505	June	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**505**
506	July	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**506**
507	August	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**507**
508	September	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**508**
509	October	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**509**
510	November	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**510**
511	December	-2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**511**
512	**Total**		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**512**

6) Depreciation Expense Rate Adjustment

The Depreciation Expense Rate Adjustment is the difference between the recorded Prior Year depreciation expense and the depreciation expense amount that would have resulted from using the proposed rates.

Line				**Line**
600	Calculated Depreciation Expense for Recorded Plant Using Proposed Rates	$0	Section 5, Line 512, col 13	**600**
601	Total Prior Year Recorded Depreciation Expense	$0	Section 1, Line 102, col 13	**601**
602	**Depreciation Expense Rate Adjustment**	**$0**	Line 600 minus Line 601	**602**

Notes:

...

Schedule 12-DepRates
DEPRECIATION RATES (Note 1)

1) ELECTRIC TRANSMISSION PLANT - TO21 DEPRECIATION RATES

					Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	
					7-PlantInService, L. 112, Col 3-12		Col 1 x Col 2	10-AccDep, L. 112, Col 3-12	Col 1 - Col 3 - Col 4			Col 1 x Col 9				
					ORIGINAL	NET SALVAGE		BOOK	FUTURE	SURVIVOR	REMAINING	ANNUAL ACCRUAL				
Line	**Func**	**FERC Account**	**Asset Class**	**Asset Class Description**	**COST**	**PCT.**	**AMOUNT**	**RESERVE**	**ACCRUALS**	**CURVE**	**LIFE**	**AMOUNT**	**RATE**	**LIFE RATE**	**COR RATE**	**Line**
100	ETP	352.01	ETP35201	STRUCTURES AND IMPROVEMENTS	$0	(20)	$0	$0	$0	70 - R3	53.82	$0	1.63%	1.33%	0.30%	**100**
101	ETP	352.02	ETP35202	STRUCTURES AND IMPROVEMENTS - EQUIPMENT	$0	(20)	$0	$0	$0	70 - R3	60.38	$0	1.70%	1.41%	0.29%	**101**
102	ETP	353.01	ETP35301	STATION EQUIPMENT	$0	(60)	$0	$0	$0	47 - R2	37.27	$0	3.63%	2.13%	1.50%	**102**
103	ETP	353.02	ETP35302	STATION EQUIPMENT - STEP-UP TRANSFORMERS	$0	(5)	$0	$0	$0	55 - R2	32.92	$0	1.75%	1.61%	0.14%	**103**
104	ETP	354	ETP35400	TOWERS AND FIXTURES	$0	(100)	$0	$0	$0	75 - R4	57.16	$0	2.91%	1.27%	1.65%	**104**
105	ETP	355	ETP35500	POLES AND FIXTURES	$0	(80)	$0	$0	$0	56 - R1.5	49.51	$0	3.24%	1.74%	1.50%	**105**
106	ETP	356	ETP35600	OVERHEAD CONDUCTORS AND DEVICES	$0	(110)	$0	$0	$0	65 - R1.5	55.87	$0	3.43%	1.48%	1.95%	**106**
107	ETP	357	ETP35700	UNDERGROUND CONDUIT	$0	0	$0	$0	$0	65 - R4	50.51	$0	1.53%	1.53%	0.01%	**107**
108	ETP	358	ETP35800	UNDERGROUND CONDUCTORS AND DEVICES	$0	(10)	$0	$0	$0	55 - R3	39.88	$0	1.99%	1.75%	0.23%	**108**
109	ETP	359	ETP35900	ROADS AND TRAILS	$0	(10)	$0	$0	$0	60 - R1.5	54.09	$0	1.90%	1.69%	0.21%	**109**
110		**TOTAL TRANSMISSION PLANT**			**$0**		**$0**	**$0**	**$0**			**$0**	**#DIV/0!**	1.84%	#DIV/0!	**110**

2) ELECTRIC TRANSMISSION PLANT - TO20 AUTHORIZED DEPRECIATION RATES (Note 2) (Note 3)

The depreciation rates in this table will only be utilized for TO21-RY2024 to calculate the depreciation accruals in Column 3 of 7-PlantInService for the forecast periods in 2023.
Forecast periods in 2023 accrue depreciation expense from the authorized TO20 depreciation rates. All other forecast periods beyond 2023 in Column 3 of 7-PlantInService will be calculated using the depreciation rates in Table 1 (above) of this tab (12-DepRates).

					Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	
					7-PlantInService, L. 112, Col 3-12		Col 1 x Col 2	10-AccDep, L. 112, Col 3-12	Col 1 - Col 3 - Col 4			Col 1 x Col 9				
					ORIGINAL	NET SALVAGE		BOOK	FUTURE	SURVIVOR	REMAINING	ANNUAL ACCRUAL				
Line	**Func**	**FERC Account**	**Asset Class**	**Asset Class Description**	**COST**	**PCT.**	**AMOUNT**	**RESERVE**	**ACCRUALS**	**CURVE**	**LIFE**	**AMOUNT**	**RATE**	**LIFE RATE**	**COR RATE**	**Line**
200	ETP	352.01	ETP35201	STRUCTURES AND IMPROVEMENTS	$0	(20)	$0	$0	$0	70 - R3	57.45	$0	1.63%	1.33%	0.31%	**200**
201	ETP	352.02	ETP35202	STRUCTURES AND IMPROVEMENTS - EQUIPMENT	$0	(20)	$0	$0	$0	70 - R3	63.80	$0	1.71%	1.41%	0.30%	**201**
202	ETP	353.01	ETP35301	STATION EQUIPMENT	$0	(60)	$0	$0	$0	46 - R2	37.87	$0	3.13%	2.13%	1.00%	**202**
203	ETP	353.02	ETP35302	STATION EQUIPMENT - STEP-UP TRANSFORMERS	$0	(5)	$0	$0	$0	55 - R1.5	34.30	$0	1.66%	1.54%	0.12%	**203**
204	ETP	354	ETP35400	TOWERS AND FIXTURES	$0	(100)	$0	$0	$0	75 - R4	57.03	$0	2.30%	1.19%	1.11%	**204**
205	ETP	355	ETP35500	POLES AND FIXTURES	$0	(80)	$0	$0	$0	54 - R1.5	46.49	$0	3.16%	1.71%	1.44%	**205**
206	ETP	356	ETP35600	OVERHEAD CONDUCTORS AND DEVICES	$0	(110)	$0	$0	$0	65 - R2	51.91	$0	2.72%	1.36%	1.36%	**206**
207	ETP	357	ETP35700	UNDERGROUND CONDUIT	$0	0	$0	$0	$0	65 - R4	54.80	$0	1.53%	1.52%	0.01%	**207**
208	ETP	358	ETP35800	UNDERGROUND CONDUCTORS AND DEVICES	$0	(10)	$0	$0	$0	55 - R3	43.69	$0	1.99%	1.76%	0.23%	**208**
209	ETP	359	ETP35900	ROADS AND TRAILS	$0	(10)	$0	$0	$0	60 - R1.5	52.76	$0	1.86%	1.65%	0.22%	**209**
210		**TOTAL TRANSMISSION PLANT**			**$0**		**$0**	**$0**	**$0**			**$0**	**#DIV/0!**	1.83%	#DIV/0!	**210**

3) COMMON, GENERAL AND INTANGIBLE (CGI) PLANT (Note 5)

Line	**Func**	**FERC Account**	**Asset Class**	**Asset Class Description**	**DEPRECIATION ACCRUAL RATES**	**Line**
300			CMP30101	ORGANIZATION - COMMON PLANT	0.00	**300**
301			CMP30200	FRANCHISES AND CONSENTS - COMMON PLANT	0.00	**301**
302			CMP30301	MISCELLANEOUS INTANGIBLE PLANT	3.39	**302**
303			CMP30302	SOFTWARE	17.36	**303**
304			CMP30304	SOFTWARE CIS	9.01	**304**
305			CMP38901	LAND - COMMON PLANT	0.00	**305**
306			CMP38902	LAND RIGHTS	2.58	**306**
307			CMP39000	STRUCTURES AND IMPROVEMENTS	1.97	**307**
308			CMP39001	COMM PLANT: LEASEHOLD IMPR	20.00	**308**
309			CMP39101	OFFICE MACHINES	27.31	**309**
310			CMP39102	PC HARDWARE	14.17	**310**
311			CMP39103	OFFICE FURNITURE AND EQUIPMENT	7.50	**311**
312			CMP39104	OFFICE MACHINES AND COMPUTER EQUIPMENT - CIS - FULLY ACCRUED	27.31	**312**
313			CMP39201	TRANSPORTATION EQUIPMENT - AIR	1.36	**313**
314			CMP39202	TRANSPORTATION EQUIPMENT - CLASS P	13.48	**314**
315			CMP39203	TRANSPORTATION EQUIPMENT - CLASS C2	9.92	**315**
316			CMP39204	TRANSPORTATION EQUIPMENT - CLASS C4	10.13	**316**
317			CMP39205	TRANSPORTATION EQUIPMENT - CLASS T1	10.11	**317**
318			CMP39206	TRANSPORTATION EQUIPMENT - CLASS T3	9.10	**318**
319			CMP39207	TRANSPORTATION EQUIPMENT - CLASS T4	6.82	**319**
320			CMP39208	TRANSPORTATION EQUIPMENT - VESSELS	4.15	**320**
321			CMP39209	TRANSPORTATION EQUIPMENT - TRAILERS	3.07	**321**
322			CMP39300	STORES EQUIPMENT	6.25	**322**
323			CMP39400	TOOLS, SHOP AND GARAGE EQUIPMENT	3.34	**323**
324			CMP39500	LABORATORY EQUIPMENT	7.77	**324**
325			CMP39600	POWER OPERATED EQUIPMENT	6.45	**325**
326			CMP39701	COMMUNICATION EQUIPMENT - NON-COMPUTER	14.45	**326**
327			CMP39702	COMMUNICATION EQUIPMENT - COMPUTER	20.47	**327**

328	CMP39703	COMMUNICATION EQUIPMENT - RADIO SYSTEMS	15.25	**328**
329	CMP39704	COMMUNICATION EQUIPMENT - VOICE SYSTEMS	14.61	**329**
330	CMP39705	COMMUNICATION EQUIPMENT - TRANSMISSION SYSTEMS	4.79	**330**
331	CMP39706	COMMUNICATION EQUIPMENT - TRANSMISSION SYSTEMS, GAS AMI	5.14	**331**
332	CMP39707	COMMUNICATION EQUIPMENT - TRANSMISSION SYSTEMS, ELECTRIC AMI	0.83	**332**
333	CMP39708	AMI COMMUNICATION NETWORK	4.87	**333**
334	CMP39800	MISCELLANEOUS EQUIPMENT	5.36	**334**
335	CMP39900	OTHER TANGIBLE PROPERTY	0.21	**335**
336	EGP38901	LAND	0.00	**336**
337	EGP38902	LAND RIGHTS	2.99	**337**
338	EGP39000	STRUCTURES AND IMPROVEMENTS	1.58	**338**
339	EGP39100	OFFICE FURNITURE AND EQUIPMENT	5.93	**339**
340	EGP39400	TOOLS, SHOP AND WORK EQUIPMENT	3.94	**340**
341	EGP39500	LABORATORY EQUIPMENT	4.74	**341**
342	EGP39600	POWER OPERATED EQUIPMENT	7.89	**342**
343	EGP39700	COMMUNICATION EQUIPMENT	6.92	**343**
344	EGP39708	AMI COMMUNICATION NETWORK	4.96	**344**
345	EGP39800	MISCELLANEOUS EQUIPMENT	6.85	**345**
346	EIP30201	FRANCHISES AND CONSENTS	2.40	**346**
347	EIP30301	USBR - LIMITED TERM ELECTRIC	0.00	**347**
348	EIP30303	COMPUTER SOFTWARE	20.42	**348**

Notes:

1) Depreciation Rates in this Schedule cannot be changed without FERC authorization from a Section 205 or 206 filing.
2) Depreciation Rates in Lines 200-209, cols 9, 10, and 11 are TO20 authorized rates. Please see the Offer of Settlement from PG&E's October 15, 2020 global settlement filing.
3) Depreciation Rates in Lines 200-210 will only be used for TO21-RY2024 for forecasted periods in 2023. It will remain presented in subsequent TO21 Annual Update Filings, but will not be used to calculate forecasted depreciation accruals in Schedule 9 (9-PlantAdditions).
4) Account 350.02-Land Rights, was calculated by using the composite depreciation rate excluding net salvage for transmission plant, as of December 31, 2022, to arrive at the stated rate shown (Line 110, col 10). This rate cannot be changed absent a section 205 or 206 filing.
5) See CPUC Decision 20-12-005. In the event the CPUC modifies these depreciation rates in the future, pursuant to the Protocols, PG&E will make a single issue filing at FERC to modify these rates.
...

Schedule 13-WorkCap
Calculation of Components of Working Capital
Input cells are shaded gold

Prior Year: -2

1) Calculation of Materials and Supplies

Materials and Supplies balances are recorded in FERC Account 154 and are assigned to Network Transmission based on warehouse data at the Major Work Category level.

			Col 1	Col 2	Col 3	Col 4	
			Note 1	Note 2	Col 2 * 24-Allocators, L. 126	Col 2 * 24-Allocators, L. 127	
Line	Month	Year	Total Company Materials & Supplies	Total Network Transmission	High Voltage	Low Voltage	Line
100	December	-3			#DIV/0!	#DIV/0!	100
101	January	-2			#DIV/0!	#DIV/0!	101
102	February	-2			#DIV/0!	#DIV/0!	102
103	March	-2			#DIV/0!	#DIV/0!	103
104	April	-2			#DIV/0!	#DIV/0!	104
105	May	-2			#DIV/0!	#DIV/0!	105
106	June	-2			#DIV/0!	#DIV/0!	106
107	July	-2			#DIV/0!	#DIV/0!	107
108	August	-2			#DIV/0!	#DIV/0!	108
109	September	-2			#DIV/0!	#DIV/0!	109
110	October	-2			#DIV/0!	#DIV/0!	110
111	November	-2			#DIV/0!	#DIV/0!	111
112	December	-2			#DIV/0!	#DIV/0!	112
113	**13-Month Average**		**$0**	**$0**	**#DIV/0!**	**#DIV/0!**	113

2) Calculation of Prepayments

Prepaid property insurance is allocated to Electric Transmission Network (ETN) based on plant ratios. Prepaid liability insurance is allocated to ETN based on a 50% plant, 50% labor ratio. Other prepayments are allocated to ETN based on the labor ratio.

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	
	Data Source:		FF1 110-111, L. 57, col c	Note 3	col 3 - col 4	Note 4	Note 5	Note 6	
				Less:		Detail of Adjusted Total Prepaids			
Line	Month	Year	Total Company Prepayments	Direct Assignments	Adjusted Total	Property Insurance	Liability Insurance	Misc.	Line
200	December	-3			$0				200
201	January	-2			$0				201
202	February	-2			$0				202
203	March	-2			$0				203
204	April	-2			$0				204
205	May	-2			$0				205
206	June	-2			$0				206
207	July	-2			$0				207
208	August	-2			$0				208
209	September	-2			$0				209
210	October	-2			$0				210
211	November	-2			$0				211

Calculation of Components of Working Capital **Prior Year: -2**

Input cells are shaded gold

212	December	-2			$0				**212**
	Allocation Method from Total Company to Electric Transmission Network					**Network Transmission Plant Factor (Total Company)**	**50% Plant / 50% Labor Network Transmission Blended Factor (Total Company)**	**Network Transmission Labor Factor (Total Company)**	
213	Allocation Factor	24-Allocators, L. 116, L. 135, L. 113				#DIV/0!	#DIV/0!	#DIV/0!	**213**
214	**a) 13 Month Avg Calculation**	(Sum Line 200 to Line 212) / 13	#DIV/0!	#DIV/0!	$0	#DIV/0!	#DIV/0!	#DIV/0!	**214**
215	Allocated Prepayments	Line 213 * Line 214			**#DIV/0!**	#DIV/0!	#DIV/0!	#DIV/0!	**215**
216	**b) EOY Calculation**	Line 212	$0	$0	$0	$0	$0	$0	**216**
217	Allocated Prepayments	Line 213 * Line 216			**#DIV/0!**	#DIV/0!	#DIV/0!	#DIV/0!	**217**

Notes:

1) Materials and Supplies month-end balances are extracted from SAP by querying by General Ledger (GL) Account. December balances are from FF1 227, L. 12, cols b and c.

2) PG&E's supply chain management team uses Materials and Supplies balances at the Major Work Category level by warehouse to assign to functional areas.
For warehouses that serve as distribution centers for multiple functional areas, PG&E allocates to functional areas based on the respective warehouse's historical consumption data.

3) PG&E conducted a query of the subaccounts of General Ledger (GL) Account 165 and removed all prepayments that are directly assigned to PG&E's Generation department in col 4.

4) PG&E conducted a query of GL Acct 165 for prepaid amounts related to A&G account 924 property insurance and reflected the month-end recorded balances in col 6.

5) PG&E conducted a query of GL Acct 165 for prepaid amounts related to A&G account 925 general liability insurance and reflected the month-end recorded balances in col 7.

6) PG&E conducted a query of GL Acct 165 for other prepaid amounts consisting of Acct 308.1 excise taxes, property taxes and miscellaneous and reflected the month-end recorded balances in col 8.

...

Schedule 14-ADIT
Accumulated Deferred Income Taxes | Prior Year: -2
Input cells are shaded gold

1) Summary of Accumulated Deferred Income Taxes

a) End of Year Accumulated Deferred Income Taxes

Line	Col 1 Account	Col 2 Total ADIT	Col 3 Source	Line
100	Account 190	#DIV/0!	Line 212, Col. 2	100
101	Account 282	#DIV/0!	Line 309, Col. 2	101
102	Account 283	#DIV/0!	Line 406, Col. 2	102
103	Account 255	#DIV/0!	Line 505, Col. 2	103
104	Total Accumulated Deferred Income Taxes	#DIV/0!	Sum of Lines 100 to 103	104

b) Beginning of Year Accumulated Deferred Income Taxes

Line		BOY ADIT	Source	Line
105	Total Accumulated Deferred Income Taxes		WP_14-ADIT 1, L. 100, col 7	105

c) Average of Beginning and End of Year Accumulated Deferred Income Taxes

Line		Average ADIT	Source	Line
106	Weighted Average ADIT:	#DIV/0!	Line 614, Col. 8	106
107	Adjustment for Forecasted Proration vs Actual Proration:	$0	WP_14_ADIT, Tab 8, Col 13, Line 130	107
108	Adjusted Average ADIT	#DIV/0!	Line 106 + Line 107	108

2) Account 190 Detail

Line	ACCT 190	Col 1 DESCRIPTION	Col 2 END BAL per G/L Sum Col 3 to Col 6	Col 3 Gas and Other Non-ISO Related Costs	Col 4 ISO Only	Col 5 Electric Plant Related	Col 6 Electric Labor Related	Col 7 Description	Reference	Line
	Electric:									
200			$0						WP_14-ADIT 2, L. 100, Col 2	200
201			$0						WP_14-ADIT 2, L. 101, Col 2	201
202			$0						WP_14-ADIT 2, L. 102, Col 2	202
203			$0						WP_14-ADIT 2, L. 103, Col 2	203
204			$0						WP_14-ADIT 2, L. 104, Col 2	204
205			$0						WP_14-ADIT 2, L. 105, Col 2	205
206			$0						WP_14-ADIT 2, L. 106, Col 2 and WP_14-ADIT 3, L. 113	206
207			$0						WP_14-ADIT 2, L. 107, Col 2	207
208			$0						WP_14-ADIT 2, L. 108, Col 2	208
209			$0						WP_14-ADIT 2, L. 109, Col 2 and Notes	209
210		Total Account 190	$0	$0	$0	$0	$0	Sum of Above Lines beginning on Line 200		210
211		Allocation Factors (Plant and Labor)		$0		#DIV/0!	#DIV/0!	24-Allocators, L. 119, 112		211
212		**Total Account 190 ADIT** (Sum of amounts in Columns 4 to 6)	**#DIV/0!**		$0	#DIV/0!	#DIV/0!	Line 210 * Line 211 for Cols 5 and 6		212
213		FERC Form 1 Account 190		Must match amount on Line 210 Col 2					FF1 234, L. 18, col c	213

3) Account 282 Detail

Line	ACCT 282	Col 1 DESCRIPTION	Col 2 END BAL per G/L Sum Col 3 to Col 6	Col 3 Gas and Other Non-ISO Related Costs	Col 4 ISO Only	Col 5 Total Company Plant Related	Col 6 Total Company Labor Related	Col 7 Description		Line
300			$0						WP_14-ADIT 4, L. 103, Col 2	300
301			$0							301
302			$0						WP_14-ADIT 4, L. 117, Col 2	302
303			$0							303
304			$0							304
305			$0							305
306			$0							306
307		Total Account 282	$0	$0	$0	$0	$0	Sum of Above Lines beginning on Line 300		307
308		Allocation Factors (Plant and Labor)			#DIV/0!	#DIV/0!	#DIV/0!	24-Allocators, L. 122, 116, 113		308
309		**Total Account 282 ADIT** (Sum of amounts in Columns 4 to 6)	**#DIV/0!**		#DIV/0!	#DIV/0!	#DIV/0!	Line 307 * Line 308 for Cols 4 to 6		309
310		FERC Form 1 Account 282							FF1 274-275, L. 9, col k	310
311		Not Used								311
312		FERC Form 1 Account 282	$0	Must match amount on Line 307 Col 2						312

Accumulated Deferred Income Taxes **Prior Year: -2**

Input cells are shaded gold

4) Account 283 Detail

Line	ACCT 283	Col 1 DESCRIPTION	Col 2 END BAL per G/L Sum Col 3 to Col 6	Col 3 Gas and Other Non-ISO Related Costs	Col 4 ISO Only	Col 5 Total Company Plant Related	Col 6 Total Company Labor Related	Col 7 Description		Line
	Electric:									
400			$0						FF1 276-277, L. 3 + L. 11, col k	400
401			$0						FF1 276-277, L. 4 + L. 12, col k	401
402			$0						FF1 276-277, L. 5 + L. 14 + L.18, col k	402
403										403
404		Total Account 283	$0	$0	$0	$0	$0	Sum of Above Lines beginning on Line 400		404
405		Allocation Factors (Plant and Labor)				#DIV/0!	#DIV/0!	24-Allocators, Lines 116, 113		405
406		**Total Account 283 ADIT**	**#DIV/0!**		$0	#DIV/0!	#DIV/0!	Line 404 * Line 405 for Cols 5 and 6		406
		(Sum of amounts in Columns 4 to 6)								
407		FERC Form 1 Account 283		Must match amount on Line 404 Col 2						407
									FF1 276-277, L. 19, col k	

5) Account 255 Detail

Line	ACCT 255	Col 1 DESCRIPTION	Col 2 END BAL per G/L Sum Col 3 to Col 6	Col 3 Gas and Other Non-ISO Related Costs	Col 4 ISO Only	Col 5 Total Company Plant Related	Col 6 Total Company Labor Related	Col 7 Description		Line
	Electric:									
500			$0						WP_14-ADIT 5, L. 100, Col 4	500
501			$0						WP_14-ADIT 5, L. 101 , col 4	501
502			$0							502
503		Total Electric 255	$0	$0	$0	$0	$0	Sum of Above Lines beginning on Line 500		503
504		Allocation Factors (Plant and Labor)			#DIV/0!	#DIV/0!	#DIV/0!	24-Allocators, L. 122, 116, 113		504
505		**Total Account 255 ADIT**	**#DIV/0!**		#DIV/0!	#DIV/0!	#DIV/0!	Line 503 * Line 504 for Cols 4 to 6		505
		(Sum of amounts in Columns 4 to 6)								
506		FERC Form 1 Account 255		Must match amount on Line 503 Col 2					FF1 266-267, L. 8 + L. 12, col h	506

6) Tax Normalization Calculation Pursuant to Treas. Reg §1.167(l)-1(h)(6); PLR 9313008; 9202029; 9224040; 201717008

Line	Year	Col 1 Future Test Period	Col 2 See Note 1 Mthly Deferred Tax Amount	Col 3 See Note 2 Deferred Tax Balance	Col 4 Days in Month	Col 5 Number of Days Left in Period	Col 6 Col 5 / Tot. Days Prorate Percentages	Col 7 = Col 2 * Col 6 Monthly Prorata Amounts	Col 8 Prior Month Col 8 + Col 7 Annual Accumulated Prorata Calculation	Line
600		Beginning Deferred Tax Balance (Line 105, Col. 2)		$0		365	100.00%		0	600
601	-2	January	#DIV/0!	#DIV/0!	31	335	91.78%	#DIV/0!	#DIV/0!	601
602	-2	February	#DIV/0!	#DIV/0!	28	307	84.11%	#DIV/0!	#DIV/0!	602
603	-2	March	#DIV/0!	#DIV/0!	31	276	75.62%	#DIV/0!	#DIV/0!	603
604	-2	April	#DIV/0!	#DIV/0!	30	246	67.40%	#DIV/0!	#DIV/0!	604
605	-2	May	#DIV/0!	#DIV/0!	31	215	58.90%	#DIV/0!	#DIV/0!	605
606	-2	June	#DIV/0!	#DIV/0!	30	185	50.68%	#DIV/0!	#DIV/0!	606
607	-2	July	#DIV/0!	#DIV/0!	31	154	42.19%	#DIV/0!	#DIV/0!	607
608	-2	August	#DIV/0!	#DIV/0!	31	123	33.70%	#DIV/0!	#DIV/0!	608
609	-2	September	#DIV/0!	#DIV/0!	30	93	25.48%	#DIV/0!	#DIV/0!	609
610	-2	October	#DIV/0!	#DIV/0!	31	62	16.99%	#DIV/0!	#DIV/0!	610
611	-2	November	#DIV/0!	#DIV/0!	30	32	8.77%	#DIV/0!	#DIV/0!	611
612	-2	December	#DIV/0!	#DIV/0!	31	1	0.27%	#DIV/0!	#DIV/0!	612
613		Ending Balance		#DIV/0!						613
614								Weighted Average ADIT Balance:	**#DIV/0!**	614

Accumulated Deferred Income Taxes

Input cells are shaded gold

Prior Year: -2

7) Tax Normalization Calculation Pursuant to Treas. Reg §1.167(l)-1(h)(6); PLR 9313008; 9202029; 9224040; 201717008 for the Forecasted Plant Additions

		Assumption Tax Depreciation - MACRS Half Year Convention over 15-Year Tax Life			Year 1 Tax Depr Rate	Year 2 Tax Depr Rate							
			Gross		5.00%	9.50%	0.00%	1-BaseTRR, Line 405		Prorata	Monthly	Accumulated	
			Plant Adds	Book Deprec	Tax Deprec	Tax Deprec	ADIT projected	Amortization of Excess ADIT	Adjusted ADIT Projected	Percentages	ADIT	ADIT	
		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	
Line	Year	Plant Additions	9-PlantAdditions Col 1, Lines 100-111	Col 2 * 12-DepRates, Col 9, Line 110/12 * Remaining Months	Col 2 * Col 1, Line 729		Col 3 - Col 4 * 1-BaseTRR Line 402	1-BaseTRR, Line 405/12	Col 6 + Col 7	Col 6, Lines 600-612	Col 8 * Col 9	Prior Month Col 11 + Col 10	
700	-1	January	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	91.78%	#DIV/0!	#DIV/0!	700
701	-1	February	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	84.11%	#DIV/0!	#DIV/0!	701
702	-1	March	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	75.62%	#DIV/0!	#DIV/0!	702
703	-1	April	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	67.40%	#DIV/0!	#DIV/0!	703
704	-1	May	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	58.90%	#DIV/0!	#DIV/0!	704
705	-1	June	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	50.68%	#DIV/0!	#DIV/0!	705
706	-1	July	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	42.19%	#DIV/0!	#DIV/0!	706
707	-1	August	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	33.70%	#DIV/0!	#DIV/0!	707
708	-1	September	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	25.48%	#DIV/0!	#DIV/0!	708
709	-1	October	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	16.99%	#DIV/0!	#DIV/0!	709
710	-1	November	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	8.77%	#DIV/0!	#DIV/0!	710
711	-1	December	$0	#DIV/0!	-		#DIV/0!	$0	#DIV/0!	0.27%	#DIV/0!	#DIV/0!	711
712		Sub-total Additions	**$0**	**#DIV/0!**	**-**		**#DIV/0!**	**$0**	**#DIV/0!**				712
713		Balance					#DIV/0!		#DIV/0!	100%	#DIV/0!	#DIV/0!	713

			Plant Adds	Filing Year & Rate Year Plt Adds Book Deprec Rate Year	Rate Year Plt Adds Rate Year Tax Deprec	Filing Year Plt Adds Rate Year Tax Deprec	ADIT projected	Amortization of Excess ADIT	Adjusted ADIT Projected	Prorata Percentages	Monthly ADIT	Accumulated ADIT	
Line		Rate Year Plant Additions	9-PlantAdditions Col 1, Lines 112-123	((Col 2, Line 712/12)*12-DepRates, Col 9, Line 110) + ((Col 2*12-DepRates, Col 9, Line 110/)12 * Remaining Months)	Col 2 * Col 1, Line 729	Col 2, Line 712 * Col 1, Line 730/12	Col 3 - Col 4 - Col 5 * 1-BaseTRR Line 402	1-BaseTRR, Line 405/12	Col 6 + Col 7	Col 6, Lines 600-612	Col 8 * Col 9	Prior Month Col 11 + Col 10	
714	0	January	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	91.78%	#DIV/0!	#DIV/0!	714
715	0	February	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	84.11%	#DIV/0!	#DIV/0!	715
716	0	March	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	75.62%	#DIV/0!	#DIV/0!	716
717	0	April	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	67.40%	#DIV/0!	#DIV/0!	717
718	0	May	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	58.90%	#DIV/0!	#DIV/0!	718
719	0	June	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	50.68%	#DIV/0!	#DIV/0!	719
720	0	July	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	42.19%	#DIV/0!	#DIV/0!	720
721	0	August	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	33.70%	#DIV/0!	#DIV/0!	721
722	0	September	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	25.48%	#DIV/0!	#DIV/0!	722
723	0	October	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	16.99%	#DIV/0!	#DIV/0!	723
724	0	November	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	8.77%	#DIV/0!	#DIV/0!	724
725	0	December	$0	#DIV/0!	-	-	#DIV/0!	$0	#DIV/0!	0.27%	#DIV/0!	#DIV/0!	725
726		Sub-total Additions	**$0**	**#DIV/0!**	**-**	**-**	**#DIV/0!**	**$0**	**#DIV/0!**				726
727		**Total Additions**	**$0**	**#DIV/0!**	**$0**	**$0**	**#DIV/0!**					#DIV/0!	727
728		Impact of ADIT on Forecasted Plant Additions Plus Amortization of Excess ADIT										#DIV/0!	728
												Note 3	

Line	Year	Table 1 - MACRS 15-Yr Prop	Line
729	1	5.00%	729
730	2	9.50%	730
731	3	8.55%	731
732	4	7.70%	732
733	5	6.93%	733
734	6	6.23%	734
735	7	5.90%	735
736	8	5.90%	736
737	9	5.91%	737
738	10	5.90%	738
739	11	5.91%	739
740	12	5.90%	740
741	13	5.91%	741
742	14	5.90%	742
743	15	5.91%	743
744	16	2.95%	744

Notes:

1) The monthly deferred tax amounts are equal to the ending ADIT balance minus the beginning ADIT balance, divided by 12 months.

2) For January through December = previous month balance plus amount in col 2.

3) Formula for Line 728 (Line 727 x 1-BaseTRR L. 220) x (1-BaseTRR L. 402/(1 - 1-BaseTRR L. 402))+(Line 727 x 1-BaseTRR L 216)

...

Schedule 15-NUC
Network Upgrade Credit and Interest Expense **Prior Year: -2**
Input cells are shaded gold

Beginning of Year Balances

Line	Description	Balance	Source	Notes	Line
100	Outstanding Network Upgrade Credits Recorded in FERC Acct 252		WP_15-NUC 1, L. 100, col 10		100
101	FERC Acct 252 Other	$0	Line 102 - Line 100		101
102	Total Acct 252 - Customer Advances for Construction		FF1 112-113, L. 56, col d		102

End of Year Balances

Line	Description	Balance	Source	Notes	Line
103	Outstanding Network Upgrade Credits		WP_15-NUC 2, L. 100, col 10		103
104	FERC Acct 252 - Other	$0	Line 105 - Line 103		104
105	Total Acct 252 - Customer Advances for Construction		FF1 112-113, L. 56, col c		105
106	Interest on Network Upgrade Credits Recorded in FERC Acct 431		WP_15-NUC 2, L. 101, col 7		106
107	FERC Acct 431 - Other	$0	Line 108 - Line 106		107
108	Total Acct 431 - Other Interest Expense		FF1 114-117, L. 68, col c		108
109	**Average of EOY and BOY**	**#DIV/0!**	Average of Lines 100 and 103		109

Notes:

...

Schedule 16-UnfundedReserves
Unfunded Reserves **Prior Year: -2**
Input cells are shaded gold

Line		Values	Source	Notes	Line
	1) Summary of Unfunded Reserves Average Balances				
100	Sum of 13-Month Averages	#DIV/0!	Sum Lines 219, 316, 416, 516, ...		**100**
101	Sum of EOY Values	#DIV/0!	Sum Lines 216, 314, 414, 514, ...		**101**

2) Calculation of Allocated Accrued Vacation

Line	Month	Year	Total Company Monthly Value	Source	Notes	Line
200	December	-3			Note 1	**200**
201	January	-2			Note 1	**201**
202	February	-2			Note 1	**202**
203	March	-2			Note 1	**203**
204	April	-2			Note 1	**204**
205	May	-2			Note 1	**205**
206	June	-2			Note 1	**206**
207	July	-2			Note 1	**207**
208	August	-2			Note 1	**208**
209	September	-2			Note 1	**209**
210	October	-2			Note 1	**210**
211	November	-2			Note 1	**211**
212	December	-2			Note 1	**212**
213	Less: Permanent Accounting Adjustment				Note 2	**213**
214	EOY Net Accrued Vacation		$0	Line 212 + Line 213		**214**
215	Network Transmission Labor Factor (Total Company)		#DIV/0!	24-Allocators, Line 113		**215**
216	**EOY Allocated Accrued Vacation**		**#DIV/0!**	Line 214 * Line 215		**216**
217	13-Month Average Company Accrued Vacation Liability		#DIV/0!	Average of Lines 200 - 212		**217**
218	13-Month Average Net Accrued Vacation		#DIV/0!	Line 217 + Line 213		**218**
219	**13-Month Average Allocated Accrued Vacation**		**#DIV/0!**	Line 215 * Line 218		**219**

3) Calculation of Injuries and Damages

Line	Month	Year	Total Company Monthly Value	Source	Notes

300	December	-3		WP_16-UnfundedReserves, L. 201, Col 8	300
301	January	-2		WP_16-UnfundedReserves, L. 202, Col 8	301
302	February	-2		WP_16-UnfundedReserves, L. 203, Col 8	302
303	March	-2		WP_16-UnfundedReserves, L. 204, Col 8	303
304	April	-2		WP_16-UnfundedReserves, L. 205, Col 8	304
305	May	-2		WP_16-UnfundedReserves, L. 206, Col 8	305
306	June	-2		WP_16-UnfundedReserves, L. 207, Col 8	306
307	July	-2		WP_16-UnfundedReserves, L. 208, Col 8	307
308	August	-2		WP_16-UnfundedReserves, L. 209, Col 8	308
309	September	-2		WP_16-UnfundedReserves, L. 210, Col 8	309
310	October	-2		WP_16-UnfundedReserves, L. 211, Col 8	310
311	November	-2		WP_16-UnfundedReserves, L. 212, Col 8	311
312	December	-2		WP_16-UnfundedReserves, L. 213, Col 8	312
313	Network Transmission Blended Factor (Total Company)		#DIV/0!	24-Allocators, Line 135	313
314	**EOY Allocated Injuries and Damages**		**#DIV/0!**	Line 312 * Line 313	**314**
315	13-Month Average Injuries and Damages		#DIV/0!	Average of Lines 300 - 312	315
316	**13-Month Average Allocated Injuries and Damages**		**#DIV/0!**	Line 315 * Line 313	**316**

4) Calculation of Severances

Line	Month	Year	Total Company Monthly Value	Source	Notes	
400	December	-3		WP_16-UnfundedReserves, L. 301, Col 4		400
401	January	-2		WP_16-UnfundedReserves, L. 302, Col 4		401
402	February	-2		WP_16-UnfundedReserves, L. 303, Col 4		402
403	March	-2		WP_16-UnfundedReserves, L. 304, Col 4		403
404	April	-2		WP_16-UnfundedReserves, L. 305, Col 4		404
405	May	-2		WP_16-UnfundedReserves, L. 306, Col 4		405
406	June	-2		WP_16-UnfundedReserves, L. 307, Col 4		406
407	July	-2		WP_16-UnfundedReserves, L. 308, Col 4		407
408	August	-2		WP_16-UnfundedReserves, L. 309, Col 4		408
409	September	-2		WP_16-UnfundedReserves, L. 310, Col 4		409
410	October	-2		WP_16-UnfundedReserves, L. 311, Col 4		410
411	November	-2		WP_16-UnfundedReserves, L. 312, Col 4		411
412	December	-2		WP_16-UnfundedReserves, L. 313, Col 4		412
413	Network Transmission Labor Factor (Total Company)		#DIV/0!	24-Allocators, Line 113		413
414	**EOY Allocated Severances**		**#DIV/0!**	Line 412 * Line 413		414
415	13-Month Average Severances		#DIV/0!	Average of Lines 400 - 412		415
416	**13-Month Average Allocated Severances**		**#DIV/0!**	Line 415 * Line 413		416

5) Placeholder for New Unfunded Reserves (to specify) - Note 3

Line	Month	Year	Total Company Monthly Value	Source	Notes	
500	December	-3				500
501	January	-2				501
502	February	-2				502
503	March	-2				503
504	April	-2				504
505	May	-2				505
506	June	-2				506
507	July	-2				507
508	August	-2				508
509	September	-2				509
510	October	-2				510
511	November	-2				511
512	December	-2				512
513	Allocation Factor (to specify)					513
514	**EOY Allocated**		**$0**	Line 512 * Line 513		514

515	13-Month Average	#DIV/0!	Average of Lines 500 - 512	515
516	**13-Month Average Allocated**	**#DIV/0!**	Line 513 * Line 515	516

Notes:
1) PG&E conducts a query in SAP of GL Acct 2420024 Accrued Vacation Liability and reflects 13 months of balances.
2) The amount of $45,700,000 represents a one-time accounting adjustment to increase the vacation accrual that was never reflected in operating expenses, never recovered from customers and was instead absorbed by shareholders. For Rate Year 2024 100% of the adjustment is applied, for Rate Year 2025, 70% is applied, for Rate Year 2026, 30% is applied, and for Rate Year 2027 and beyond, 0% is applied.

3) PG&E defines a new unfunded reserve as: (1) funds included in the revenue requirement or otherwise recovered from TO customers; (2) significantly in advance of expenditure; (3) that have not been set aside in a trust, escrow, restricted, or interest-earning account; and (4) that meet the FERC definition of a contingent liability. PG&E will identify new unfunded reserves on a case-by-case basis.
For each new unfunded reserve identified, PG&E will add in a new section similar to Lines 500 - 516 to provide the 13-month values and apply with an appropriate factor to determine the unfunded reserve rate base on the allocated end of year balances as well as 13-month average balances.
The formula on Line 100 and 101 would require update to pick up the appropriate value when new unfunded reserves are identified.
...

Schedule 17-RegAssets-1

Regulatory Assets and Liabilities and Associated Amortization and Regulatory Debits and Credits **Prior Year: -2**

Input cells are shaded gold

Other Regulatory Assets and Liabilities are a component of Rate Base representing costs that have been deferred to a future period and recorded in Other Regulatory Assets (Account 182.3) and Regulatory Liabilities (Account 254). This Schedule does not include Abandoned or Cancelled Projects costs recovered through Schedule 8.

PG&E will include a non-zero amount of Other Regulatory Assets and Liabilities only with Commission approval received subsequent to a PG&E Section 205 filing requesting such treatment.

Amortization and Regulatory Debits and Credits are costs of revenues that are approved for recovery from or return to customers in this formula transmission rate. Approved costs are amortized as expenses or revenue in the Base TRR, consistent with a Commission Order.

1) Calculation of Regulatory Assets and Liabilities and Amortization of Debits and Credits

Instructions:

1) Upon Commission approval of recovery of Other Regulatory Assets and Liabilities, Amortization and Regulatory Debits and Credits costs through this formula transmission rate:

a) Fill in Description for issue in above table.

b) Enter costs in columns 1-3 in above table for the applicable Prior Year.

2) Insert additional lines as necessary for additional issues.

Line		Prior Year Amount	Calculation or Source	Line
100	Other Regulatory Assets and Liabilities (EOY):	$0	Line 103, col 2	100
101	Other Regulatory Assets and Liabilities (BOY/EOY average):	$0	Avg. of Line 103 col 1 and col 2	101
102	Amortization and Regulatory Debits and Credits:	$0	Line 103, col 3	102

Line	Description of Issue Resulting in Other Regulatory Asset/Liability	col 1 Prior Year BOY Other Reg Asset/Liability	col 2 Prior Year EOY Other Reg Asset/Liability	col 3 Prior Year Amortization or Regulatory Debit/Credit	Commission Order Granting Approval of Regulatory Liability	Source	Line
103	**Sum of below**	$0	$0	$0			103
104	Issue #1						104
105	Issue #2						105
106	Issue #3						106
107	…						107

2) Unamortized Excess ADIT and Tax Normalization Calculation Pursuant to Treas. Reg §1.167(l)-1(h)(6); PLR 9313008; 9202029; 922404; 201717008

Line	Description	Value	Source	Line
200	BOY Unamortized Excess Federal Accumulated Deferred Income Taxes	$0	17-RegAssets-2, L. 110, Col 17 + 17-RegAssets-3, L. 110, Col 17 (zero in 2017 only)	200
201	EOY Unamortized Excess Federal Accumulated Deferred Income Taxes	$0	17-RegAssets-2, L. 110, Col 24 + 17-RegAssets-3, L. 110, Col 24	201
202	Weighted Average ADIT Balance	$0	Line 217, Col 8	202

Line	Year	Col 1 Future Test Period	Col 2 See Note 1 Mthly Deferred Tax Amount	Col 3 See Note 2 Deferred Tax Balance	Col 4 Days in Month	Col 5 Number of Days Left in Period	Col 6 Col 5 / Tot. Days Prorata Percentages	Col 7 = Col 2 * Col 6 Monthly Prorata Amounts	Col 8 Prior Month Col 8 + Col 7 Annual Accumulated Prorata Calculation	Line
203		Beginning Deferred Tax Balance (Line 200)		$0		365	100.00%		0	203
204	-2	January	$0	$0	31	335	91.78%	$0	0	204
205	-2	February	$0	$0	28	307	84.11%	$0	0	205
206	-2	March	$0	$0	31	276	75.62%	$0	0	206
207	-2	April	$0	$0	30	246	67.40%	$0	0	207
208	-2	May	$0	$0	31	215	58.90%	$0	0	208
209	-2	June	$0	$0	30	185	50.68%	$0	0	209
210	-2	July	$0	$0	31	154	42.19%	$0	0	210
211	-2	August	$0	$0	31	123	33.70%	$0	0	211
212	-2	September	$0	$0	30	93	25.48%	$0	0	212
213	-2	October	$0	$0	31	62	16.99%	$0	0	213
214	-2	November	$0	$0	30	32	8.77%	$0	0	214
215	-2	December	$0	$0	31	1	0.27%	$0	0	215
216		Ending Balance		$0						216
217							Weighted Average ADIT Balance:		**0**	217

Notes:
1) The monthly deferred tax amounts are equal to the ending ADIT balance minus the beginning ADIT balance, divided by 12 months.
2) For January through December = previous month balance plus amount in col 2.
...

Schedule 17-RegAssets-2
Amortization of (Excess)/Deficient Deferred Federal and State Income Taxes (Note 1)
Input cells are shaded gold

Prior Year: -2

Line	DESCRIPTION		Originating Excess/Deficient ADIT Recorded Account	Col 0 Originating Timing Difference 12/31/2017	Order 864 Permanent Worksheet(s) Category 1 Information Col 1 ADIT Balance Prior to TCJA @ 35% FIT 12/31/2017	Col 2 Remeasurement ADIT Balance @ 21% FIT 12/31/2017	Col 3 Col 1 - Col 2 (Excess)/Deficient ADIT Note F Balance 12/31/2017	Category 2 Information Col 4 FERC Account (Excess)/Deficient ADIT Recorded Acct 182.3 / Acct 254	Category 3 Information Col 5 UNAMORTIZED EXCESS FEDERAL ACCUMULATED DEFERRED INCOME TAXES Beg Bal PROTECTED FIXED ASSETS	Col 6 Beg Bal UNPROTECTED FIXED ASSETS	Col 7 Beg Bal UNPROTECTED NON FIXED ASSETS	Col 8 Sum Col 5 to Col 7 Beg Bal TOTALS	Category 5 Information Col 9 Amortization Period ARAM/Years	Col 10 PRIOR PERIOD AMORTIZATION OF EXCESS FEDERAL ACCUMULATED DEFERRED INCOME TAXES Amortization Expense PROTECTED FIXED ASSETS	Col 11 Amortization Expense UNPROTECTED FIXED ASSETS	Col 12 Amortization Expense UNPROTECTED NON FIXED ASSETS	Category 4 Information Col 13 FERC Account ADIT Amortization Recorded Acct 410.1 / Acct 411.1
100	Method Life	Note A	Acct # 282	0	0	0	0	Acct # 254	0	0	0	0	ARAM	0	0	0	Acct # 411.1
101	Cost of Removal	Note B	Acct # 282	0	0	0	0	Acct # 254	0	0	0	0	ARAM	0	0	0	Acct # 411.1
102	Fixed Assets Book Tax Basis Differences	Note C	Acct # 282	0	0	0	0	Acct # 254	0	0	0	0	130 Months (Note G)	0	0	0	Acct # 411.1
103	Non Fixed Assets Book Tax Basis Differences	Note D	Acct # 190/ # 282	0	0	0	0	Acct # 182.3	0	0	0	0	130 Months (Note G)	0	0	0	Acct # 410.1
104	Non Fixed Asset Book Tax Differences	Net Operating Loss Carryover Note E	Acct # 190	0	0	0	0	Acct # 182.3	0	0	0	0	ARAM	0	0	0	Acct # 410.1
105	Total			0	0	0	0		0	0	0	0		0	0	0	
106	Adjustments to December 31, 2017 Amounts																
107	Adjustment for Repairs Off-System			0	0	0	0	Acct #	0	0	0	0	ARAM	0	0	0	Acct #
108	...			0	0	0	0	Acct #	0	0	0	0	ARAM	0	0	0	Acct #
109	...			0	0	0	0	Acct #	0	0	0	0	ARAM	0	0	0	Acct #
110	Total Including Adjustments			0	0	0	0		0	0	0	0		0	0	0	
Line	Details of ADIT	Note 1															
200	Total Method Life			0	0	0	0		0	0	0	0		0	0	0	
201	FERC CA Method/Life	Includes Cost of Removal	Acct # 282					Acct # 254	0	0	0	0	ARAM		0	0	Acct # 411.1
202	FERC Fed Method/Life	Includes Cost of Removal	Acct # 282					Acct # 254	0	0	0	0	ARAM		0	0	Acct # 411.1
203	FERC St Off Method/Life	Includes Cost of Removal	Acct # 282					Acct # 254	0	0	0	0	ARAM		0	0	Acct # 411.1
204	...								0	0	0	0			0	0	
205	...								0	0	0	0			0	0	
Line																	
300	Total Cost of Removal			0	0	0	0		0	0	0	0		0	0	0	
301	Cost of Removal	TBD	Acct # 282					Acct # 254	0	0	0	0				0	
302	Cost of Removal	TBD	Acct # 282					Acct # 254	0	0	0	0				0	
303	Cost of Removal	TBD	Acct # 282					Acct # 254	0	0	0	0				0	
304	...								0	0	0	0				0	
305	...								0	0	0	0				0	
Line																	
400	Total Fixed Assets Book Tax Basis Differences			0	0	0	0		0	0	0	0		0	0	0	
401	FERC Audit Adjustment		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
402	FERC Fed 1033 Involuntary Conv		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
403	FERC Fed 263a F&C 2014		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
404	FERC Fed 263a F&C Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
405	FERC Fed AFUDC Equity		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
406	FERC Fed Audit Adj Bonus		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
407	FERC Fed Casualty Loss 2008		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
408	FERC Fed CIAC		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
409	FERC Fed COR Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
410	FERC Fed ITC Basis Red		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
411	FERC Fed Other Book Only		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
412	FERC Fed Overheads		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
413	FERC Fed Repair 2014		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
414	FERC Fed Repair 2014 Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
415	FERC Fed Repair Allow		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
416	FERC Fed Repair Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
417	FERC Fed Software		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
418	FERC Fed Software CA NO		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
419	FERC Fed Software FT-		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
420	FERC Fed TOA Capitalization		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
421	FERC Fed TOA Capitalization CA Norm		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
422	FERC Fed TOA Software Other		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
423	FERC Reg Plant Disallowance		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
424	FERC St Off 1033 Involuntary Conv		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
425	FERC St Off 263a F&C 2014		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
426	FERC St Off 263a F&C CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
427	FERC St Off 263a F&C Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
428	FERC St Off AFUDC Equity		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
429	FERC St Off AFUDC Equity CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
430	FERC St Off Audit Adjustment		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
431	FERC St Off Audit Adjustment CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
432	FERC St Off Casualty Loss 2008		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
433	FERC St Off CIAC		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
434	FERC St Off COR Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
435	FERC St Off ITC Basis Red		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
436	FERC St Off ITC Basis Red CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
437	FERC St Off Other Book Only		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
438	FERC St Off Overheads		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
439	FERC St Off Overheads CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
440	FERC St Off Reg Plant Disallow Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
441	FERC St Off Repair 2014		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
442	FERC St Off Repair 2014 CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
443	FERC St Off Repair 2014 Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
444	FERC St Off Repair Allow		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
445	FERC St Off Repair Allow CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
446	FERC St Off Repair CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
447	FERC St Off Repair Fed		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
448	FERC St Off Software		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
449	FERC St Off Software CA NO		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
450	FERC St Off Software FT-		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
451	FERC St Off TOA Capital CA Norm		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
452	FERC St Off TOA Capitaliz CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
453	FERC St Off TOA Capitalization		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
454	FERC St Off TOA Other CA		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
455	FERC St Off TOA Software Other		Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1
456	...								0	0	0	0		0		0	
457	...								0	0	0	0		0		0	
Line																	
500	Total Non Fixed Assets Book Tax Basis Differences			0	0	0	0		0	0	0	0		0	0	0	
501	Vacation Pay Timing Differences		Acct # 190					Acct # 182.3	0	0	0	0	130 Months	0	0		Acct # 410.1
502	Property Tax Timing Differences		Acct # 190					Acct # 182.3	0	0	0	0	130 Months	0	0		Acct # 410.1
502a	Property Tax - Correction of 2017 FERC Form 1 Error		Acct # 190					Acct # 182.3	0	0	0	0	130 Months	0	0		Acct # 410.1
503	FERC Fed AFUDC Debt		Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1
504	FERC Fed FAS34 Cap Int		Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1
505	FERC Fed Sec 263a Cap Int		Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1
506	FERC St Off AFUDC Debt		Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1
507	FERC St Off FAS34 Cap Int		Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1
508	FERC St Off Sec 263a Cap Int		Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1
509	...								0	0	0	0		0	0		
510	...								0	0	0	0		0	0		
Line																	
600	Total Non Fixed Asset Book Tax Differences			0	0	0	0		0	0	0	0		0	0	0	
601	Net Operating Loss Deferred Taxes		Acct # 190					Acct # 182.3	0	0	0	0	ARAM		0	0	Acct # 410.1
602	...		Acct # 190					Acct # 182.3	0	0	0	0	ARAM		0	0	Acct # 410.1
603	...								0	0	0	0			0	0	
604									0	0	0	0			0	0	
605									0	0	0	0			0	0	
Line																	
700	Adjustments to December 31, 2017 Amounts			0	0	0	0		0	0	0	0		0	0	0	
701	FERC Fed 2017 481a Adj								0	0	0	0					
702	FERC Fed 2017 481a Bon Add Back								0	0	0	0					
703	FERC Fed St Off 2017 481a Adj CA								0	0	0	0					
704	...								0	0	0	0					
705	...								0	0	0	0					

Category 3 Information Col 14 Col 5 - Col 10 UNAMORTIZED EXCESS FEDERAL ACCUMULATED DEFERRED INCOME TAXES - BEGINNING BALANCE End Bal PROTECTED FIXED ASSETS	Col 15 Col 6 - Col 11 End Bal UNPROTECTED FIXED ASSETS	Col 16 Col 7 - Col 12 End Bal UNPROTECTED NON FIXED ASSETS	Col 17 Sum Col 14 to Col 16 End Bal TOTALS	Col 18 CURRENT PERIOD AMORTIZATION OF EXCESS FEDERAL ACCUMULATED DEFERRED INCOME TAXES Amortization Expense PROTECTED FIXED ASSETS	Col 19 Amortization Expense UNPROTECTED FIXED ASSETS	Col 20 Amortization Expense UNPROTECTED NON FIXED ASSETS	Category 3 Information Col 21 Col 14 - Col 18 UNAMORTIZED EXCESS FEDERAL ACCUMULATED DEFERRED INCOME TAXES - ENDING BALANCE End Bal PROTECTED FIXED ASSETS	Col 22 Col 15 - Col 19 End Bal UNPROTECTED FIXED ASSETS	Col 23 Col 16 - Col 20 End Bal UNPROTECTED NON FIXED ASSETS	Col 24 Sum Col 21 to Col 23 End Bal TOTALS	Col 25 Col 24 x Gross-up (Excess)/Deficient ADIT Including Gross- 1.38857	Reference	Line
0	0	0	0	0	0	0	0	0	0	0	0		100
0	0	0	0	0	0	0	0	0	0	0	0		101
0	0	0	0	0	0	0	0	0	0	0	0		102
0	0	0	0	0	0	0	0	0	0	0	0		103
0	0	0	0	0	0	0	0	0	0	0	0		104
0	0	0	0	0	0	0	0	0	0	0	0		105
													106
0	0	0	0	0	0	0	0	0	0	0	0		107
0	0	0	0	0	0	0	0	0	0	0	0		108
0	0	0	0	0	0	0	0	0	0	0	0		109
0	0	0	0	0	0	0	0	0	0	0	0		110
													Line
0	0	0	0	0	0	0	0	0	0	0	0		200
0	0	0	0		0	0	0	0	0	0	0		201
0	0	0	0		0	0	0	0	0	0	0		202
0	0	0	0		0	0	0	0	0	0	0		203
0	0	0	0		0	0	0	0	0	0	0		204
0	0	0	0		0	0	0	0	0	0	0		205
													Line
0	0	0	0	0	0	0	0	0	0	0	0		300
0	0	0	0			0	0	0	0	0	0		301
0	0	0	0			0	0	0	0	0	0		302
0	0	0	0			0	0	0	0	0	0		303
0	0	0	0			0	0	0	0	0	0		304
0	0	0	0			0	0	0	0	0	0		305
													Line
0	0	0	0	0	0	0	0	0	0	0	0		400
0	0	0	0	0		0	0	0	0	0	0		401
0	0	0	0	0		0	0	0	0	0	0		402
0	0	0	0	0		0	0	0	0	0	0		403
0	0	0	0	0		0	0	0	0	0	0		404
0	0	0	0	0		0	0	0	0	0	0		405
0	0	0	0	0		0	0	0	0	0	0		406
0	0	0	0	0		0	0	0	0	0	0		407
0	0	0	0	0		0	0	0	0	0	0		408
0	0	0	0	0		0	0	0	0	0	0		409
0	0	0	0	0		0	0	0	0	0	0		410
0	0	0	0	0		0	0	0	0	0	0		411
0	0	0	0	0		0	0	0	0	0	0		412
0	0	0	0	0		0	0	0	0	0	0		413
0	0	0	0	0		0	0	0	0	0	0		414
0	0	0	0	0		0	0	0	0	0	0		415
0	0	0	0	0		0	0	0	0	0	0		416
0	0	0	0	0		0	0	0	0	0	0		417
0	0	0	0	0		0	0	0	0	0	0		418
0	0	0	0	0		0	0	0	0	0	0		419
0	0	0	0	0		0	0	0	0	0	0		420
0	0	0	0	0		0	0	0	0	0	0		421
0	0	0	0	0		0	0	0	0	0	0		422
0	0	0	0	0		0	0	0	0	0	0		423
0	0	0	0	0		0	0	0	0	0	0		424
0	0	0	0	0		0	0	0	0	0	0		425
0	0	0	0	0		0	0	0	0	0	0		426
0	0	0	0	0		0	0	0	0	0	0		427
0	0	0	0	0		0	0	0	0	0	0		428
0	0	0	0	0		0	0	0	0	0	0		429
0	0	0	0	0		0	0	0	0	0	0		430
0	0	0	0	0		0	0	0	0	0	0		431
0	0	0	0	0		0	0	0	0	0	0		432
0	0	0	0	0		0	0	0	0	0	0		433
0	0	0	0	0		0	0	0	0	0	0		434
0	0	0	0	0		0	0	0	0	0	0		435
0	0	0	0	0		0	0	0	0	0	0		436
0	0	0	0	0		0	0	0	0	0	0		437
0	0	0	0	0		0	0	0	0	0	0		438
0	0	0	0	0		0	0	0	0	0	0		439
0	0	0	0	0		0	0	0	0	0	0		440
0	0	0	0	0		0	0	0	0	0	0		441
0	0	0	0	0		0	0	0	0	0	0		442
0	0	0	0	0		0	0	0	0	0	0		443
0	0	0	0	0		0	0	0	0	0	0		444
0	0	0	0	0		0	0	0	0	0	0		445
0	0	0	0	0		0	0	0	0	0	0		446
0	0	0	0	0		0	0	0	0	0	0		447
0	0	0	0	0		0	0	0	0	0	0		448
0	0	0	0	0		0	0	0	0	0	0		449
0	0	0	0	0		0	0	0	0	0	0		450
0	0	0	0	0		0	0	0	0	0	0		451
0	0	0	0	0		0	0	0	0	0	0		452
0	0	0	0	0		0	0	0	0	0	0		453
0	0	0	0	0		0	0	0	0	0	0		454
0	0	0	0	0		0	0	0	0	0	0		455
0	0	0	0	0		0	0	0	0	0	0		456
0	0	0	0	0		0	0	0	0	0	0		457
													Line
0	0	0	0	0	0	0	0	0	0	0	0		500
0	0	0	0	0	0		0	0	0	0	0		501
0	0	0	0	0	0		0	0	0	0	0		502
0	0	0	0	0	0		0	0	0	0	0		502a
0	0	0	0	0	0		0	0	0	0	0		503
0	0	0	0	0	0		0	0	0	0	0		504
0	0	0	0	0	0		0	0	0	0	0		505
0	0	0	0	0	0		0	0	0	0	0		506
0	0	0	0	0	0		0	0	0	0	0		507
0	0	0	0	0	0		0	0	0	0	0		508
0	0	0	0	0	0		0	0	0	0			509
0	0	0	0	0	0		0	0	0	0			510
													Line
0	0	0	0	0	0	0	0	0	0	0	0		600
0	0	0	0		0	0	0	0	0	0	0		601
0	0	0	0		0	0	0	0	0	0	0		602
0	0	0	0		0	0	0	0	0	0	0		603
0	0	0	0		0	0	0	0	0	0	0		604
0	0	0	0		0	0	0	0	0	0	0		605
0	0	0	0				0	0	0	0			
													Line
0	0	0	0	0	0	0	0	0	0	0	0		700
0	0	0	0				0	0	0	0	0		701
0	0	0	0				0	0	0	0	0		702
0	0	0	0				0	0	0	0	0		703
0	0	0	0				0	0	0	0	0		704
0	0	0	0				0	0	0	0	0		705

Note 1 This Schedule 17-RegAsset-2 reflects the federal income tax rate change due to the Tax Cuts and Job Act (TCJA). This Schedule will be replicated for each tax rate change after the TCJA (see 17-RegAsset-3).
Note A Reflects the deferred tax liability (DTL) for the difference between book and tax depreciation methods and depreciable lives on plant capitalized for both book and tax. Method life is a protected timing difference.
Note B Reflects the deferred tax asset (DTA) difference between the book accrual and actual spending for cost of removal.
Note C Reflects the DTL difference between tax basis deductions and book depreciation on these tax basis deductions.
Note D Reflects the DTA difference between non-fixed asset tax deductions and book deductions.
Note E Reflects the tax net operating loss DTA. The net operating loss DTA is protected.
Note F Basis for allocation is the 2017 value from Tab 24-Allocators, Rows 17 and 23 for common and direct function groups, respectively.
Note G Pursuant to ER17-2154-002 OFFER OF SETTLEMENT AND STIPULATION, Section 2.1.1.
Note H The “grossed-up” portion from Column 25 is excluded from rate base.
Note I The TO19 settlement provided for a base 130-months amortization subject to adjustment per Section 2.2.1. As a result, the overall amortization period may not be 130-months.
...

Schedule 17-RegAssets-3
Amortization of (Excess)/Deficient Deferred Federal and State Income Taxes (Note 1)
Input cells are shaded gold

Prior Year: -2

Line	DESCRIPTION			Originating Excess/Deficient ADIT Recorded Account	Col 0 Originating Timing Difference 12/31/2017	Col 1 ADIT Balance Prior to ~~TCJA~~ @ 21% FIT 12/31/2017	Col 2 Remeasurement ADIT Balance @ xx% FIT 12/31/2017	Col 3 Col 1 - Col 2 (Excess)/Deficient ADIT Note F ~~ADIT~~ Balance 12/31/2017	Col 4 FERC Account (Excess)/Deficient ADIT Recorded Acct 182.3 / Acct 254	Col 5 Beg Bal PROTECTED FIXED ASSETS	Col 6 Beg Bal UNPROTECTED FIXED ASSETS	Col 7 Beg Bal UNPROTECTED NON FIXED ASSETS	Col 8 Sum Col 5 to Col 7 Beg Bal TOTALS	Col 9 Amortization Period ARAM/Years	Col 10 Amortization Expense PROTECTED FIXED ASSETS	Col 11 Amortization Expense UNPROTECTED FIXED ASSETS	Col 12 Amortization Expense UNPROTECTED NON FIXED ASSETS	Col 13 FERC Account ADIT Amortization Recorded Acct 410.1 / Acct 411.1	Col 14 Col 5 - Col 10 End Bal PROTECTED FIXED ASSETS	Col 15 Col 6 - Col 11 End Bal UNPROTECTED FIXED ASSETS	Col 16 Col 7 - Col 12 End Bal UNPROTECTED NON FIXED ASSETS	Col 17 Sum Col 14 to Col 16 End Bal TOTALS	Col 18 Amortization Expense PROTECTED FIXED ASSETS	Col 19 Amortization Expense UNPROTECTED FIXED ASSETS	Col 20 Amortization Expense UNPROTECTED NON FIXED ASSETS	Col 21 Col 14 - Col 18 End Bal PROTECTED FIXED ASSETS	Col 22 Col 15 - Col 19 End Bal UNPROTECTED FIXED ASSETS	Col 23 Col 16 - Col 20 End Bal UNPROTECTED NON FIXED ASSETS	Col 24 Sum Col 21 to Col 23 End Bal TOTALS	25 Col 24 x Gross-up (Excess)/Deficient ADIT Including Gross-up of 1.38857	Reference	Line
						Order 864 Permanent Worksheet(s) Category 1 Information			Category 2 Information	Category 3 Information				Category 5 Information				Category 4 Information	Category 3 Information							Category 3 Information						
										UNAMORTIZED (EXCESS)/DEFICIENT FEDERAL ACCUMULATED DEFERRED INCOME TAXES					PRIOR PERIOD AMORTIZATION OF (EXCESS)/DEFICIENT FEDERAL ACCUMULATED DEFERRED INCOME TAXES				UNAMORTIZED (EXCESS)/DEFICIENT FEDERAL ACCUMULATED DEFERRED INCOME TAXES - BEGINNING BALANCE				CURRENT PERIOD AMORTIZATION OF (EXCESS)/DEFICIENT FEDERAL ACCUMULATED DEFERRED INCOME TAXES			UNAMORTIZED (EXCESS)/DEFICIENT FEDERAL ACCUMULATED DEFERRED INCOME TAXES - ENDING BALANCE						
100	Method Life		Note A	Acct # 282	0	0	0	0	Acct # 254	0	0	0	0	ARAM	0	0	0	Acct # 411.1	0	0	0	0	0	0	0	0	0	0	0	0		100
101	Cost of Removal		Note B	Acct # 282	0	0	0	0	Acct # 254	0	0	0	0	ARAM	0	0	0	Acct # 411.1	0	0	0	0	0	0	0	0	0	0	0	0		101
102	Fixed Assets Book Tax Basis Differences		Note C	Acct # 282	0	0	0	0	Acct # 254	0	0	0	0	130 Months (Note G)	0	0	0	Acct # 411.1	0	0	0	0	0	0	0	0	0	0	0	0		102
103	Non Fixed Assets Book Tax Basis Differences		Note D	Acct # 190/ # 282	0	0	0	0	Acct # 182.3	0	0	0	0	131 Months (Note G)	0	0	0	Acct # 410.1	0	0	0	0	0	0	0	0	0	0	0	0		103
104	Non Fixed Asset Book Tax Differences	Net Operating Loss Carryover	Note E	Acct # 190	0	0	0	0	Acct # 182.3	0	0	0	0	ARAM	0	0	0	Acct # 410.1	0	0	0	0	0	0	0	0	0	0	0	0		104
105	Total				0	0	0	0		0	0	0	0		0	0	0		0	0	0	0	0	0	0	0	0	0	0	0		105
106	Adjustments to December 31, 2017 Amounts																															106
107	ADIT Item 1	Adjustment for Abandoned or Cancelled Projects			0	0	0	0	Acct #	0	0	0	0	ARAM	0	0	0	Acct #	0	0	0	0	0	0	0	0	0	0	0	0		107
108	...				0	0	0	0	Acct #	0	0	0	0	ARAM	0	0	0	Acct #	0	0	0	0	0	0	0	0	0	0	0	0		108
109	...				0	0	0	0	Acct #	0	0	0	0	ARAM	0	0	0	Acct #	0	0	0	0	0	0	0	0	0	0	0	0		109
110	Total Including Adjustments				0	0	0	0		0	0	0	0		0	0	0		0	0	0	0	0	0	0	0	0	0	0	0		110
Line	Details of ADIT		Note 1																													Line
200	Total Method Life				0	0	0	0		0	0	0	0		0	0	0		0	0	0	0	0	0	0	0	0	0	0	0		200
201	FERC CA Method/Life		Includes Cost of Removal	Acct # 282					Acct # 254	0	0	0	0	ARAM		0	0	Acct # 411.1	0	0	0	0		0	0	0	0	0	0	0		201
202	FERC Fed Method/Life		Includes Cost of Removal	Acct # 282					Acct # 254	0	0	0	0	ARAM		0	0	Acct # 411.1	0	0	0	0		0	0	0	0	0	0	0		202
203	FERC St Off Method/Life		Includes Cost of Removal	Acct # 282					Acct # 254	0	0	0	0	ARAM		0	0	Acct # 411.1	0	0	0	0		0	0	0	0	0	0	0		203
204	...									0	0	0	0			0	0		0	0	0	0		0	0	0	0	0	0	0		204
205	...									0	0	0	0			0	0		0	0	0	0		0	0	0	0	0	0	0		205
Line																																Line
300	Total Cost of Removal				0	0	0	0		0	0	0	0		0	0	0		0	0	0	0	0	0	0	0	0	0	0	0		300
301	Cost of Removal		TBD	Acct # 282					Acct # 254	0	0	0	0				0		0	0	0	0			0	0	0	0	0	0		301
302	Cost of Removal		TBD	Acct # 282					Acct # 254	0	0	0	0				0		0	0	0	0			0	0	0	0	0	0		302
303	Cost of Removal		TBD	Acct # 282					Acct # 254	0	0	0	0				0		0	0	0	0			0	0	0	0	0	0		303
304	...									0	0	0	0				0		0	0	0	0			0	0	0	0	0	0		304
305	...									0	0	0	0				0		0	0	0	0			0	0	0	0	0	0		305
Line																																Line
400	Total Fixed Assets Book Tax Basis Differences				0	0	0	0		0	0	0	0		0	0	0		0	0	0	0	0	0	0	0	0	0	0	0		400
401	FERC Audit Adjustment			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		401
402	FERC Fed 1033 Involuntary Conv			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		402
403	FERC Fed 263a F&C 2014			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		403
404	FERC Fed 263a F&C Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		404
405	FERC Fed AFUDC Equity			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		405
406	FERC Fed Audit Adj Bonus			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		406
407	FERC Fed Casualty Loss 2008			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		407
408	FERC Fed CIAC			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		408
409	FERC Fed COR Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		409
410	FERC Fed ITC Basis Red			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		410
411	FERC Fed Other Book Only			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		411
412	FERC Fed Overheads			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		412
413	FERC Fed Repair 2014			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		413
414	FERC Fed Repair 2014 Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		414
415	FERC Fed Repair Allow			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		415
416	FERC Fed Repair Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		416
417	FERC Fed Software			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		417
418	FERC Fed Software CA NO			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		418
419	FERC Fed Software FT-			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		419
420	FERC Fed TOA Capitalization			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		420
421	FERC Fed TOA Capitalization CA Norm			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		421
422	FERC Fed TOA Software Other			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		422
423	FERC Reg Plant Disallowance			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		423
424	FERC St Off 1033 Involuntary Conv			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		424
425	FERC St Off 263a F&C 2014			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		425
426	FERC St Off 263a F&C CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		426
427	FERC St Off 263a F&C Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		427
428	FERC St Off AFUDC Equity			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		428
429	FERC St Off AFUDC Equity CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		429
430	FERC St Off Audit Adjustment			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		430
431	FERC St Off Audit Adjustment CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		431
432	FERC St Off Casualty Loss 2008			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		432
433	FERC St Off CIAC			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		433
434	FERC St Off COR Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		434
435	FERC St Off ITC Basis Red			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		435
436	FERC St Off ITC Basis Red CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		436
437	FERC St Off Other Book Only			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		437
438	FERC St Off Overheads			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		438
439	FERC St Off Overheads CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		439
440	FERC St Off Reg Plant Disallow Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		440
441	FERC St Off Repair 2014			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		441
442	FERC St Off Repair 2014 CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		442
443	FERC St Off Repair 2014 Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		443
444	FERC St Off Repair Allow			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		444
445	FERC St Off Repair Allow CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		445
446	FERC St Off Repair CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		446
447	FERC St Off Repair Fed			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		447
448	FERC St Off Software			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		448
449	FERC St Off Software CA NO			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		449
450	FERC St Off Software FT-			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		450
451	FERC St Off TOA Capital CA Norm			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		451
452	FERC St Off TOA Capitaliz CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		452
453	FERC St Off TOA Capitalization			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		453
454	FERC St Off TOA Other CA			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		454
455	FERC St Off TOA Software Other			Acct # 282					Acct # 254	0	0	0	0	ARAM	0		0	Acct # 411.1	0	0	0	0	0		0	0	0	0	0	0		455
456	...									0	0	0	0		0		0		0	0	0	0	0		0	0	0	0	0	0		456
457	...									0	0	0	0		0		0		0	0	0	0	0		0	0	0	0	0	0		457
Line																																Line
500	Total Non Fixed Assets Book Tax Basis Differences				0	0	0	0		0	0	0	0		0	0	0		0	0	0	0	0	0	0	0	0	0	0	0		500
501	Vacation Pay Timing Differences			Acct # 190					Acct # 182.3	0	0	0	0	130 Months	0	0		Acct # 410.1	0	0	0	0	0	0		0	0	0	0	0		501
502	Property Tax Timing Differences			Acct # 190					Acct # 182.3	0	0	0	0	130 Months	0	0		Acct # 410.1	0	0	0	0	0	0		0	0	0	0	0		502
503	FERC Fed AFUDC Debt			Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1	0	0	0	0	0	0		0	0	0	0	0		503
504	FERC Fed FAS34 Cap Int			Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1	0	0	0	0	0	0		0	0	0	0	0		504
505	FERC Fed Sec 263a Cap Int			Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1	0	0	0	0	0	0		0	0	0	0	0		505
506	FERC St Off AFUDC Debt			Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1	0	0	0	0	0	0		0	0	0	0	0		506
507	FERC St Off FAS34 Cap Int			Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1	0	0	0	0	0	0		0	0	0	0	0		507
508	FERC St Off Sec 263a Cap Int			Acct # 282					Acct # 254	0	0	0	0	130 Months	0	0		Acct # 411.1	0	0	0	0	0	0		0	0	0	0	0		508
509	...									0	0	0	0		0	0			0	0	0	0	0	0		0	0	0	0	0		509
508	...									0	0	0	0		0	0			0	0	0	0	0	0		0	0	0	0	0		508
Line																																Line
600	Total Non Fixed Asset Book Tax Differences				0	0	0	0		0	0	0	0		0	0	0		0	0	0	0	0	0	0	0	0	0	0	0		600
601	Net Operating Loss Deferred Taxes			Acct # 190					Acct # 182.3	0	0	0	0	ARAM		0	0	Acct # 410.1	0	0	0	0		0	0	0	0	0	0	0		601
602	Net Operating Loss Deferred Taxes - 2018 True Up			Acct # 190					Acct # 182.3	0	0	0	0	ARAM		0	0	Acct # 410.1	0	0	0	0		0	0	0	0	0	0	0		602
603	...									0	0	0	0			0	0		0	0	0	0		0	0	0	0	0	0	0		603
604	...									0	0	0	0			0	0		0	0	0	0		0	0	0	0	0	0	0		604
605	...									0	0	0	0			0	0		0	0	0	0		0	0	0	0	0	0	0		605
																			0	0												
Line																																Line
700	Adjustments to December 31, 2017 Amounts				0	0	0	0		0	0	0	0		0	0	0		0	0	0	0	0	0	0	0	0	0	0	0		700
701	ADIT Item 1									0	0	0	0						0	0	0	0				0	0	0	0	0		701
702	...									0	0	0	0						0	0	0	0				0	0	0	0	0		702
703	...									0	0	0	0						0	0	0	0				0	0	0	0	0		703
704	...									0	0	0	0						0	0	0	0				0	0	0	0	0		704
705	...									0	0	0	0						0	0	0	0				0	0	0	0	0		705

Note 1 This Schedule 17-RegAssets-3 will reflect tax rate changes occurring after the TCJA.
Note A Reflects the deferred tax liability (DTL) for the difference between book and tax depreciation methods and depreciable lives on plant capitalized for both book and tax. Method life is a protected timing difference.
Note B Reflects the deferred tax asset (DTA) difference between the book accrual and actual spending for cost of removal.
Note C Reflects the DTL difference between tax basis deductions and book depreciation on these tax basis deductions.
Note D Reflects the DTA difference between non-fixed asset tax deductions and book deductions.
Note E Reflects the tax net operating loss DTA. The net operating loss DTA is protected.
Note F Basis for allocation is the 2017 value from Tab 24-Allocators, Rows 17 and 23 for common and direct function groups,
Note G Pursuant to ER17-2154-002 OFFER OF SETTLEMENT AND STIPULATION, Section 2.1.1.
...

Schedule 18-OandM
Operations and Maintenance Expense
Input cells are shaded gold

Prior Year: -2

Network Transmission O&M Expense (Line 100, Col 15) #DIV/0!

Source / Line	Col 1 FERC Account	Col 2 FERC Account Description	Col 3 Note 1 FF1 Recorded O&M Expense FF1 320-323, L. 83-98 and L. 101-110, col b Labor	Col 4 Note 1 Non-Labor	Col 5 Col 3 + Col 4, Note 2 Total	Col 6 Note 1, Note 4 Adjustments Labor	Col 7 Note 1, Note 4 Non-Labor	Col 8 Col 6 + Col 7 Total	Col 9 Col 3 + Col 6 Recorded Adjusted O&M Expense Labor	Col 10 Col 4 + Col 7 Non-Labor	Col 11 Col 9 + Col 10 Total	Col 12 Note 3 Network Transmission %	Col 13 Col 9 * Col 12 Network Transmission O&M Expense Labor	Col 14 Col 10 * Col 12 Non-Labor	Col 15 Col 13 + Col 14 Total	Line
100		**Total Transmission O&M**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**100**
101	560	Operation Supervision and Engineering			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**101**
102	561.1	Load Dispatch - Reliability			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**102**
103	561.2	Load Dispatch - Monitor and Operate Transmission System			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**103**
104	561.3	Load Dispatch - Transmission Service and Scheduling			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**104**
105	561.4	Scheduling, System Control and Dispatch Services (CAISO GMC)			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**105**
106	561.5	Reliability Planning and Standards Development			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**106**
107	561.6	Transmission Service Studies			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**107**
108	561.7	Generation Interconnection Studies			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**108**
109	561.8	Reliability Planning and Standards Development Services (CAISO GMC)			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**109**
110	562	Station Expenses			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**110**
111	562.1	Operation of Energy Storage Equipment			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**111**
112	563	Overhead Line Expenses			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**112**
113	564	Underground Line Expenses			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**113**
114	565	Transmission of Electricity by Others			$0			$0	$0	$0	$0		$0	$0	$0	**114**
115	566	Miscellaneous Transmission Expenses			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**115**
116	567	Rents			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**116**
117	568	Maintenance Supervision and Engineering			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**117**
118	569	Maintenance of Structures			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**118**
119	569.1	Maintenance of Computer Hardware			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**119**
120	569.2	Maintenance of Computer Software			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**120**
121	569.3	Maintenance of Communication Equipment			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**121**
122	569.4	Maintenance of Miscellaneous Regional Transmission Plant			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**122**
123	570	Maintenance of Station Equipment			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**123**
124	570.1	Maintenance of Energy Storage Equipment			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**124**
125	571	Maintenance of Overhead Lines			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**125**
126	572	Maintenance of Underground Lines			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**126**
127	573	Maintenance of Miscellaneous Transmission Plant			$0			$0	$0	$0	$0	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	**127**

Notes:
1) Data are extracted from SAP for all costs (broken down into labor and non-labor components) in the Prior Year that are recorded in electric transmission operations and maintenance expense accounts.
2) The Total FF1 Recorded O&M Expense is the sum of Labor and Non-labor FF1 Recorded O&M Expense (obtained as explained in Note 1) and tie to the amounts provided in FF1 320-323, L. 112, col b.

4) See WP_18-OandM for adjustment details.
...

Schedule 19-AandG
Administrative and General Expenses
Input Cells are shaded in gold

Prior Year: 2022

Line	Acct.	Description	Col 1 FERC Form 1 Amount	Col 2 Data Source	Col 3 See Note 1 Total Electric Amount Excluded	Col 4 Reference	Col 5 = Col 1 - Col 3 Total Electric Adj A&G Expense	Line
100	1) Calculation of Total Electric Adjusted A&G Expense							100
104	920	A&G Salaries		FF1 320-323, L. 181, col b		WP_19-AandG 1, L. 106	$0	104
105	921	Office Supplies and Expenses		FF1 320-323, L. 182, col b		WP_19-AandG 1, L. 206	$0	105
106	922	A&G Expenses Transferred		FF1 320-323, L. 183, col b		WP_19-AandG 1, L. 306	$0	106
107	923	Outside Services Employed		FF1 320-323, L. 184, col b		WP_19-AandG 1, L. 406	$0	107
108	924	Property Insurance		FF1 320-323, L. 185, col b		WP_19-AandG 1, L. 506	$0	108
109	925	Injuries and Damages		FF1 320-323, L. 186, col b		WP_19-AandG 1, L. 606	$0	109
110	926	Employee Pensions and Benefits		FF1 320-323, L. 187, col b		WP_19-AandG 1, L. 706	$0	110
111	927	Franchise Requirements		FF1 320-323, L. 188, col b		WP_19-AandG 1, L. 806	$0	111
112	928	Regulatory Commission Expenses		FF1 320-323, L. 189, col b			$0	112
113	929	Duplicate Charges		FF1 320-323, L. 190, col b			$0	113
114	930.1	General Advertising Expense		FF1 320-323, L. 191, col b		WP_19-AandG 1, L. 906	$0	114
115	930.2	Miscellaneous General Expense		FF1 320-323, L. 192, col b		WP_19-AandG 1, L. 906	$0	115
116	931	Rents		FF1 320-323, L. 193, col b			$0	116
117	935	Maintenance of General Plant		FF1 320-323, L. 196, col b		WP_19-AandG 1, L. 1006	$0	117
118		**Total A&G Expenses:**	**$0**	FF1 320-323, L. 197, col b	**$0**		**$0**	118

Line	2) Calculation of Network Transmission A&G Expense	Amount	Source	Line
201	**Based on Labor Allocation Factors**			201
202	A&G Expense after Adjustments	$0	Line 118, col 5	202
203	Less Account 924 Property Insurance nonnuclear:	$0	Line 108, col 5	203
204	Less General Liability Insurance and Injuries and Damages		WP_19-AandG 2, L. 102	204
205	Total A&G Expense Applicable to the Network Transmission Labor Factor (Total Electric):	**$0**	Line 202 - Line 203 - Line 204	205
206	Network Transmission Labor Factor (Total Electric):	#DIV/0!	24-Allocators, L. 112	206
207	Transmission Portion of A&G from Labor Allocation Factors:	**#DIV/0!**	Line 205 * Line 206	207
208	**Based on Plant Allocation Factors**			208
209	Account 924 Property Insurance nonnuclear:	$0	Line 203	209
210	Network Transmission Plant Factor (Total Electric)	#DIV/0!	24-Allocators, L. 119	210
211	Transmission Portion of Property Insurance Account 924	**#DIV/0!**	Line 209 * Line 210	211
212	**Based on Blended Labor and Plant Factor**			212
213	General Liability Insurance and Injuries and Damages:	**$0**	Line 204	213
214	Network Transmission Blended Factor (Total Electric)	#DIV/0!	24-Allocators, L. 136	214
215	Transmission Portion of General Liability Insurance and Injuries and Damages:	**#DIV/0!**	Line 213 * Line 214	215
216				216
217	Total Transmission Portion of Administrative and General Expenses:	**#DIV/0!**	Line 207 + Line 211 + Line 215	217
218	Other Administrative and General Expenses Adjustment(s)	$0		218
219		**#DIV/0!**	Line 217 + Line 218	219

Line	Acct.	3) Summary of Total Electric Adjustments	Total by FERC Account									Line
300												300
301												301
302												302
303	920	A&G Salaries	$0									303
304	921	Office Supplies and Expenses	$0									304
305	922	A&G Expenses Transferred	$0									305
306	923	Outside Services Employed	$0									306
307	924	Property Insurance	$0									307
308	925	Injuries and Damages	$0									308
309	926	Employee Pensions and Benefits	$0									309
310	927	Franchise Requirements	$0									310
311	928	Regulatory Commission Expenses	$0									311
312	929	Duplicate Charges	$0									312
313	930.1	General Advertising Expense	$0									313
314	930.2	Miscellaneous General Expense	$0									314
315	931	Rents	$0									315
316	935	Maintenance of General Plant	$0									316
317		**Total by Adjustment Type**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	317

Notes:

1 The adjustments shown in the Table above are from WP_19-AandG. Sources of adjustments are individual SAP reports by FERC account with detailed descriptions of activity and accounting information.

... ...

Schedule 20-RevenueCredits
Electric Revenue Credits
Input cells are shaded gold

Prior Year: -2
Rate Year:

1) Electric Revenue Credits

Instructions:
1) Insert additional lines as necessary for additional items.

Line	Col 1 FERC ACCT	Col 2 NATURAL ACCT	Col 3 ACCT DESCRIPTION	Col 4 Total Electric	Col 5 Network ET - High Voltage	Col 6 Network ET - Low Voltage	Col 7 Col 5 + Col 6 Total Network ET	Col 8 NP&S Transmission	Col 9 Notes	Line
100			**Totals**	**$0**	**$0**	**$0**	**$0**	**$0**	Sum Lines 201, 301, 401, 501, 601, 701, 801 and 901	100
	Forfeited Discounts									
200			**FF1 300-301, L. 16, col b**							200
201			**Acct 450 Total**	**$0**	**$0**	**$0**	**$0**	**$0**		201
202	450	4500000	Forfeited Discounts				$0		Note 2	202
203							$0			203
204	...						$0			204
	Miscellaneous Service Revenues									
300			**FF1 300-301, L. 17, col b**							300
301			**Acct 451 Total**	**$0**	**$0**	**$0**	**$0**	**$0**		301
302	451	4510000	Miscellaneous Service Revenues				$0		Note 2	302
303	451	4510007	NRD Revenue Other				$0		Note 2	303
304	451	4510040	Miscellaneous Service Electric Customer Fund Management - RES				$0		Note 2	304
305	451	4510041	Miscellaneous Service Electric Customer Fund Management Non-RES				$0		Note 2	305
306	451	4510043	Miscellaneous Service Revenues - Reimbursable				$0		Note 2	306
307							$0			307
308	...						$0			308
	Sales of Water and Water Power									
400			**FF1 300-301, L. 18, col b**							400
401			**Acct 453 Total**	**$0**	**$0**	**$0**	**$0**	**$0**		401
402	453	4530000	Sales of Water and Water Power				$0		Note 2	402
403							$0			403
404	...						$0			404
	Rents									
500			**FF1 300-301, L.19, col b**							500
501			**Acct 454 Total**	**$0**	**$0**	**$0**	**$0**	**$0**		501
502	454	4540010	Rent from Electric Property				$0		Note 2, 3	502
503	454	4540012	New Revenue Development Rent				$0		Note 2	503
504	454	4540013	New Revenue Development Fee Revenue				$0		Note 2	504
505							$0			505
506	...						$0			506
	Other Electric Revenue									
600			**FF1 300-301, L. 21-22, col b**							600
601			**Acct 456 Total**	**$0**	**$0**	**$0**	**$0**	**$0**		601
602	456	4560099	Other Electric Revenues				$0		Note 2	602
603	456		MCI Rights-of-Way (B)				$0		Note 2	603
604	456	4560050	Recreation Facilities Revenue				$0		Note 2	604
605	456	4560070	Timber Sales - Utility				$0		Note 2	605
606	456	4560014	Other Revenue - Affiliate				$0		Note 2	606
607	456	4560022	Revenue Damage Claims Electric				$0		Note 2	607
608	456	4560093	Mobile Home Park Electric				$0		Note 2	608
609	456	4560091	NEBS TCRA				$0		Note 2	609
610	456	4560098	New Revenue Development - Electric Revenue				$0		Note 2	610
611	456	4560000	Unbilled Electric Revenue				$0		Note 2	611
612	456	4560001	Reimbursed Electric Revenue				$0		Note 2, 4	612
613	456	4560002	Reimbursed Electric Revenue Joint Poles				$0		Note 2	613
614	456	4560003	Reimbursed Electric Revenue Customer Care and Billing (CC&B)				$0		Note 2	614
615	456	4560095	Other Electric Revenue - Calif Department of Water & Resources (DWR)				$0		Note 2	615
616	456	4560005	Reimbursed Electric Revenue - CPUC				$0		Note 2	616

Line	FERC Acct	Description						Notes	Line
617	456	9414000 Other Utility Operating Income				$0		Note 2	617
618	456.1	4561000 Other Transmission Revenue - Wheeling				$0		Note 2, 5	618
619	456	4560052 Other Electric Revenues				$0		Note 6	619
620	...								620
	Interdepartmental Rents								
700		**FF1 300-301, L. 20, col b**	**$0**						700
701		**Acct 455 Total**	**$0**	**$0**	**$0**	**$0**	**$0**		701
702	...					**$0**			702
703	...					**$0**			703
	Regional Control Service Revenues								
800		**FF1 300-301, L. 23, col b**	**$0**						800
801		**Acct 457.1 Total**	**$0**	**$0**	**$0**	**$0**	**$0**		801
802	...					**$0**			802
803	...					**$0**			803
	Miscellaneous Revenues								
900		**FF1 300-301, L. 24, col b**	**$0**						900
901		**Acct 457.2 Total**	**$0**	**$0**	**$0**	**$0**	**$0**		901
902	...					**$0**			902
903	...					**$0**			903

2) San Francisco General Office Sale

The purpose of this section is to return the Network Transmission portion of gain from the sale of the San Francisco General Office in 2021 to FERC customers in Rate Year 2024. It is a one-time event.

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	
Line	**Description**	**FERC Acct**	**Allocation Factor to High Voltage (Rate Year)**	**Allocation Factor to Low Voltage (Rate Year)**	**Recorded Allocated Network Transmission Amount**	**Source**	**Notes**	**Line**
1000	Rate Year High Voltage/Low Voltage Electric Transmission Plant Allocation Factor		#DIV/0!	#DIV/0!		24-Allocators, L. 133 and L. 134		**1000**
1001	Rate Year Base Transmission Revenue Requirement Adjustment	253	#DIV/0!	#DIV/0!		For Line 1001, col 5: WP_20-RevenueCredits 1, L. 102, col 2; For Line 1001, col 3 and 4: Line 1001, Col 5 * Line 1000.	Only applicable for TO21 RY2024.	**1001**
1002	Prior Year True-up Transmission Revenue Requirement Adjustment	421.1				RY2024 TO21 Model, 20-RevenueCredits, L. 1001, col 3-5	Only applicable for TO21 Prior Year 2024 true up (i.e. TO21 RY2026 annual update).	**1002**

Notes:

1) The FERC accounts listed in Col 1, match with FERC account listing under Electric Other Operating Revenues per Uniform System of Accounts.

2) To fill out Col 2-4, run SAP report by FERC accounts listed in Col 1. This SAP report lists the FERC Account detail for recorded Electric Revenue Credits amount by fiscal year, Natural Account, Major Work Categories and Regulatory Categories.

3) Line 502, Col 7 is determined through SAP Other Operating Revenue (OOR) query from Non-Energy Billing System (NEBs) for Special Facilities and Rent transactions. This report assigns functional areas and determines Network ET high and low voltage in FERC account 454, Natural Account 4540010 Rent from Electric Property.

4) Line 612, Col 7 is determined based on the SAP report described on note 2, by filtering for the appropriate Regulatory Categories (i.e. electric network transmission related).

5) See FF1 328-330, col n, Total

6) Section 1, Col 8 includes network transmission related New Products and Services revenue and SBA Transaction revenue. Please see WP_21-NPandS-1 for more details.

...

Schedule 21-NPandS

Revenue Sharing for Non-Tariff New Products & Services — **Prior Year: -2**

Input cells are shaded gold

Total NP&S Electric Transmission Revenues and Expenses

Line	Description	Values	Source	Line
100	NP&S Transmission Revenue	$0	20-RevenueCredits, L. 100, col 8	100
101	NP&S Transmission O&M Expense			101
102	NP&S Transmission A&G Expense			102
103	**Total NP&S Transmission Expense**	**$0**	Line 101 + Line 102	103

Transmission Revenues and Expenses by Product Line

		Col 1	Col 2	Col 3	Col 4	
		Note 1	Note 2	Col 1 - Col 2	Note 3	
					Adjusted	
Line	Product Line	Revenues	Expense	Net Revenues	Net Revenues	Line
200	**Total**	**$0**	**$0**	**$0**	**$0**	200
201	Wireline			$0	$0	201
202	Wireless			$0	$0	202
203	Land Use			$0	$0	203
204	Technology & Licenses			$0	$0	204
205	Maintenance & Consulting			$0	$0	205
206	SBA Transaction			$0	$0	206
207	...					207

Calculation of Pre-tax Revenue Allocation %

Line	Description	Values	Source	Line
300	PTNR (Pre-tax net revenue)	$0	Line 200, col 4	300
301	t = Composite state & federal tax rate	0.00%	1-BaseTRR, L. 402	301
302	k = The ratio of customer to shareholder after tax net revenues.	1	50%/50% = 1	302
303	PSA% (Pre-Tax Shareholder Percent of Net Revenues) = 1 / (1 + k - kt)	50.00%	1 / [1 + Line 302 - (Line 302 * Line 301)]	303
304	CRC% (Customer Revenue Credit Percent of Net Revenues) = 1 - [1 / (1+ k - kt)]	50.00%	1 - Line 303	304

Calculation of 50/50 After-Tax Sharing

Line	Description	Values	Source	Line
400	Pre-tax Shareholder Allocation (PSA$) = PTNR * PSA%	$0	Line 300 * Line 303	400
401	State and Federal taxes = PSA$ * t	$0	Line 400 * Line 301	401
402	Shareholder Allocation	$0	Line 400 - Line 401	402
403	Customer Revenue Credit (CRC$) = PTNR * CRC%	$0	Line 304 * Line 300	403

Notes:
1) Please see WP_21-NPandS 1 for Revenues by Product Line.
1) Please see WP_21-NPandS 2 for Expenses by Product Line.
3) Product Lines with negative Net Revenues are set to zero.
...

Schedule 22-TaxRates

Income Tax Rates **Prior Year: -2**

Input cells are shaded gold **Rate Year:**

1) Tax Rates for the Rate Year

Line	Description	Value	Reference	Notes	Line
100	Federal Income Tax Rate		Internal Revenue Code (IRC) Section 11		**100**
101	State Franchise Tax Rate (California)		California Rev. & Tax. Cd. § 23151		**101**
102	Federal Secondary	0.00%	Negative Line 100 * Line 101	Reflects the federal tax deduction for state taxes which reduces the composite income tax rate	**102**
103	**Composite Income Tax Rate**	**0.00%**	Sum of Lines 100-102		**103**

2) Tax Rates for the Prior Year True-up

Line	Description	Value	Reference	Notes	Line
200	Federal Income Tax Rate		Internal Revenue Code (IRC) Section 11		**200**
201	State Franchise Tax Rate (California)		California Rev. & Tax. Cd. § 23151		**201**
202	Federal Secondary	0.00%	Negative Line 200 * Line 201	Reflects the federal tax deduction for state taxes which reduces the composite income tax rate	**202**
203	**Composite Income Tax Rate**	**0.00%**	Sum of Lines 200-202		**203**

Notes:

...

Schedule 23-RetailSGTax
Retail "South Georgia" Taxes — **Prior Year: -2**
Input cells are shaded gold

1) Accumulated Deferred Income Taxes

Line	Col 1 Description	Col 2	Col 3 Values for Inputs to Sch.1-BaseTRR	Col 4 Values for Inputs to Sch.3-True-upTRR	Col 5 Source	Col 6 Notes	Line
100	**End of Year Accumulated Deferred Income Taxes**				WP_23-RetailSGTax 3	Note 1	100
101	**Beginning of Year Accumulated Deferred Income Taxes**				WP_23-RetailSGTax 3	Note 2	101
102	**Average of BOY and EOY Accumulated Deferred Income Taxes**			**#DIV/0!**	Line 414, col 9		102

2) Income Taxes

Line	Description				Source	Notes	Line
200	Federal Income Tax Rate		0.00%	0.00%	22-TaxRates, L. 100		200
201	State Income Tax Rate		0.00%	0.00%	22-TaxRates, L. 101		201
202	**Composite Tax Rate**		**0.0000%**	**0.0000%**	(Line 200 + Line 201) - (Line 200 * Line 201)		202
203	**Income Taxes:**		**#DIV/0!**	**#DIV/0!**			203

Income Taxes = [((RB * ER) + FPD) * (CTR/(1 – CTR))] + CO/(1 – CTR)]

Where:

Line	Description				Source	Notes	Line
204	RB = Rate Base		$0	#DIV/0!	Line 100 or 102		204
205	ER = Equity Rate of Return Including Common and Preferred Stock		#DIV/0!	#DIV/0!	Line 301 + Line 302		205
206	CTR = Composite Tax Rate		0.00%	0.00%	Line 202		206
207	CO = Credits and Other				WP_23-RetailSGTax 3	Note 3	207
208	FPD = Flowback and Permanent Tax Deductions		-	-			208

3) ROE and Capitalization Calculations

Line	Description		For Inputs to Sch.1-BaseTRR	For Inputs to Sch.3-True-upTRR	Source	Notes	Line
	Calculation of Cost of Capital Rate						
300	Weighted Cost of Long Term Debt		#DIV/0!	#DIV/0!	1-BaseTRR, L. 216 / 3-True-upTRR, L.201		300
301	Weighted Cost of Preferred Stock		#DIV/0!	#DIV/0!	1-BaseTRR, L. 217 / 3-True-upTRR, L. 202		301
302	Weighted Cost of Common Stock		#DIV/0!	#DIV/0!	1-BaseTRR, L. 218 / 3-True-upTRR, L.203		302
303	**Cost of Capital Rate**		#DIV/0!	#DIV/0!	Sum of Lines 300 to 302		303
304	**Return on Capital: Rate Base times Cost of Capital Rate**		**#DIV/0!**	**#DIV/0!**	Line 100 or 102 * Line 303		304
305	**Total South Georgia Adjustment**		**#DIV/0!**	**#DIV/0!**	Line 304 + Line 203		305

4) Tax Normalization Calculation Pursuant to Treas. Reg §1.167(l)-1(h)(6); PLR 9313008; 9202029; 9224040; 201717008

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	
									Col 9 Prior Mth + Col 8 Current Mth	
			See Note 4	See Note 5			Col 6 / Tot. Days	= Col 3 * Col 7		
Line	Future Test Period	Year	Mthly Deferred Tax Amount	Deferred Tax Balance	Days in Month	Number of Days Left in Period	Prorata Percentages	Monthly Prorata Amounts	Annual Accumulated Prorata Calculation	Line
400	Beginning Deferred Tax Balance (Line 101)			$0			100.00%		$0	400
401	January	-2	$0	$0	31	-31	#DIV/0!	#DIV/0!	#DIV/0!	401
402	February	-2	$0	$0		-31	#DIV/0!	#DIV/0!	#DIV/0!	402
403	March	-2	$0	$0	31	-62	#DIV/0!	#DIV/0!	#DIV/0!	403
404	April	-2	$0	$0	30	-92	#DIV/0!	#DIV/0!	#DIV/0!	404
405	May	-2	$0	$0	31	-123	#DIV/0!	#DIV/0!	#DIV/0!	405
406	June	-2	$0	$0	30	-153	#DIV/0!	#DIV/0!	#DIV/0!	406
407	July	-2	$0	$0	31	-184	#DIV/0!	#DIV/0!	#DIV/0!	407
408	August	-2	$0	$0	31	-215	#DIV/0!	#DIV/0!	#DIV/0!	408
409	September	-2	$0	$0	30	-245	#DIV/0!	#DIV/0!	#DIV/0!	409
410	October	-2	$0	$0	31	-276	#DIV/0!	#DIV/0!	#DIV/0!	410
411	November	-2	$0	$0	30	-306	#DIV/0!	#DIV/0!	#DIV/0!	411
412	December	-2	$0	$0	31	-337	#DIV/0!	#DIV/0!	#DIV/0!	412
413	Ending Balance (Line 100)			$0						413
414							**Weighted Average ADIT Balance:**		#DIV/0!	414

Notes:

1) The Source of the End of Year Accumulated Deferred Income Taxes can be found in the shaded area of WP_23-RetailSGTax 3
2) The Source of the Beginning of Year Accumulated Deferred Income Taxes can be found in the shaded area of WP_23-RetailSGTax 3
3) The Source of the Credits and Other can be found in the shaded area of WP_23-RetailSGTax 3
4) The monthly deferred tax amounts are equal to the ending ADIT balance minus the beginning ADIT balance, divided by 12 months.
5) For January through December = previous month balance plus amount in Column 2.

...

Schedule 24-Allocators
Calculation of Allocation Factors
Input cells are shaded gold

Prior Year: -2
Rate Year:

Line	Description	Value	Reference	Notes	Line
	Calculation of Prior Year Labor Allocation Factors				
100	Total Company Wages and Salaries		FF1 354-355, L. 65, col b		**100**
101	Electric A&G Wages and Salaries		FF1 354-355, L. 27, col b		**101**
102	Gas A&G Wages and Salaries		FF1 354-355, L. 61, col b		**102**
103	Cost Adjustment		WP_24-Allocators_Labor, L. 100, col 3		**103**
104	**Total Company Wages and Salaries w/o A&G**	**$0**	(Line 100 + Line 103) - (Line 101 + Line 102)		**104**
105	Total Electric Department Wages and Salaries		FF1 354-355, L. 28, col b		**105**
106	Electric A&G Wages and Salaries	$0	Line 101		**106**
107	Cost Adjustment		WP_24-Allocators_Labor, L. 100, col 5		**107**
108	**Total Adjusted Electric Wages and Salaries w/o A&G**	**$0**	Line 105 - Line 106 + Line 107		**108**
109	**Total Electric Department Labor Factor**	**#DIV/0!**	Line 108 / Line 104		**109**
	Calculation of Prior Year Network Electric Transmission Labor Allocation Factors				
110	Total Adjusted Electric Wages and Salaries w/o A&G	$0	Line 108		**110**
111	Network Electric Transmission Wages and Salaries	#DIV/0!	18-OandM, L. 100, col 13		**111**
112	**Network Transmission Labor Factor (Total Electric)**	**#DIV/0!**	Line 111 / Line 110		**112**
113	**Network Transmission Labor Factor (Total Company)**	**#DIV/0!**	Line 111 / Line 104		**113**
	Calculation of Prior Year Plant Allocation Factors				
114	Network Transmission Gross Plant In Service including CGI Plant	#DIV/0!	7-PlantInService, L. 112, col 13 + 7-PlantInService, L. 401, col 3	Prior Year Dec	**114**
115	Total PG&E Company Gross Plant In Service		WP_7-PlantInService 5, L. 149, Col 10	Prior Year Dec	**115**
116	**Network Transmission Plant Factor (Total Company)**	**#DIV/0!**	Line 114 / Line 115		**116**
117	Network Transmission Gross Plant In Service including CGI Plant	#DIV/0!	7-PlantInService, L. 112, col 13 + 7-PlantInService, L. 401, col 3	Prior Year Dec	**117**
118	Total PG&E Electric Plant In Service including CGI Plant		WP_7-PlantInService 5, L. 149, Col 8	Prior Year Dec	**118**
119	**Network Transmission Plant Factor (Total Electric)**	**#DIV/0!**	Line 117 / Line 118		**119**
120	Network Transmission Plant - Functional Plant only	$0	7-PlantInService, L. 112, col 13		**120**
121	Total Electric Transmission - Functional Plant only	$0	6-PlantJurisdiction, L. 110, col 1 + col 3		**121**
122	**Network Electric Transmission Plant Factor (Total Transmission)**	**#DIV/0!**	Line 120 / Line 121		**122**
	Calculation of Prior Year High Voltage/Low Voltage Transmission Plant Allocation Factor				
123	Network Transmission Plant - Functional Plant only	$0	7-PlantInService, L. 112, col 13	Prior Year Dec	**123**
124	High Voltage Plant	$0	7-PlantInService, L. 212, col 13	Prior Year Dec	**124**
125	Low Voltage Plant	$0	7-PlantInService, L. 312, col 13	Prior Year Dec	**125**
126	**Allocation Factor to High Voltage (Prior Year)**	**#DIV/0!**	Line 124 / Line 123		**126**
127	**Allocation Factor to Low Voltage (Prior Year)**	**#DIV/0!**	Line 125 / Line 123		**127**
	Calculation of Rate Year High Voltage/Low Voltage Electric Transmission Plant Allocation Factor				
128	High Voltage Capital Additions	$0	9-PlantAdditions, L. 223, col 2	Rate Year Dec	**128**
129	Low Voltage Capital Additions	$0	9-PlantAdditions, L. 323, col 2	Rate Year Dec	**129**
130	High Voltage Rate Year Functional Plant	$0	Line 124 + Line 128	Rate Year Dec	**130**
131	Low Voltage Rate Year Functional Plant	$0	Line 125 + Line 129	Rate Year Dec	**131**
132	Network Electric Transmission Rate Year Functional Plant	$0	Line 130 + Line 131	Rate Year Dec	**132**
133	**Allocation Factor to High Voltage (Rate Year)**	**#DIV/0!**	Line 130 / Line 132	Rate Year Dec	**133**
134	**Allocation Factor to Low Voltage (Rate Year)**	**#DIV/0!**	Line 131 / Line 132	Rate Year Dec	**134**

	Calculation of Prior Year Blended Factors			
135	**Network Transmission Blended Factor (Total Company)**	**#DIV/0!**	(50% * Line 113) + (50% *Line 116)	135
136	**Network Transmission Blended Factor (Total Electric)**	**#DIV/0!**	(50% * Line 112) + (50% *Line 119)	136
	Calculation of Prior Year Property Tax Allocation Factor			
137	Network Transmission Accumulated Depreciation including CGI	#DIV/0!	10-AccDep, L. 112, col 13 + 10-AccDep, L. 401, col 3	137
138	Total PG&E Electric Accumulated Depreciation including CGI		WP_10-AccDep 4, L. 149, Col 8	138
139	Network Transmission Net Plant in Service (Functional + CGI)	#DIV/0!	Line 117 - Line 137	139
140	Total PG&E Electric Net Plant in Service (Functional + CGI)	$0	Line 118 - Line 138	140
141	**Net Plant Property Tax Allocation Factor**	**#DIV/0!**	Line 139 / Line 140	141

Notes:

...

Schedule 25-RFandUFactors
Revenue Fees and Uncollectible Factors **Prior Year: -2**
Input cells are shaded gold

Line						Line
	1) Approved Franchise Fee Factor(s)					
	From	**To**	**Days in Prior Year**	**Franchise Fee Factor**	**Reference**	
100		Present			WP_25-RFandUFactors 1, L. 102	100
101	...					101
	2) Approved San Francisco Gross Receipts Tax Factor(s)					
	From	**To**	**Days in Prior Year**	**SFGR Tax Factor**	**Reference**	
200		Present			WP_25-RFandUFactors 2, L. 104	200
201	...					201
	3) Approved Uncollectible Factor(s)					
	From	**To**	**Days in Prior Year**	**Uncollectible Factor**	**Reference**	
300		Present			WP_25-RFandUFactors 3, L. 110	300
301	...					301
	4) Calculation of Weighted Average RF&U Factors					
400	**Franchise Fee Factor**			#DIV/0!		400
401	**SFGR Tax Factor**			#DIV/0!		401
402	**Uncollectibles Factor**			#DIV/0!		402

Notes:

...

Schedule 26-WholesaleTRRs

High and Low Voltage Wholesale Revenue Requirement **Rate Year:**

Input cells are shaded gold

Line		Col 1 Allocation Factor to High Voltage (Rate Year)	Col 2 Allocation Factor to Low Voltage (Rate Year)	Col 3 Reference	Line
1		#DIV/0!	#DIV/0!	24-Allocators, L. 133 and 134	1

Rate Base

Line	Description	High Voltage	Low Voltage	Total	Reference	Notes	Line
	Plant						
100	Transmission Functional Plant	$0	$0	$0	7-PlantInService, L. 212 and 312, col 13		100
101	Common + General + Intangible Plant	#DIV/0!	#DIV/0!	#DIV/0!	7-PlantInService, L. 401, col 4 and 5		101
102	Abandoned or Cancelled Projects	$0	$0	$0	8-AbandonedProject, Lines 100 and 101, Col 11		102
103	**Total Plant**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	Sum of Lines 100 to 102		103
	Working Capital						
104	Materials and Supplies	#DIV/0!	#DIV/0!	#DIV/0!	13-WorkCap, L. 112, col 3 and col 4		104
105	Prepayments	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 13-WorkCap, L. 217, col 5		105
106	Cash Working Capital	#DIV/0!	#DIV/0!	#DIV/0!	(Line 200 + line 200a + Line 201) / 8		106
107	**Total Working Capital**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	Sum of Lines 104 to 106		107
	Accumulated Depreciation Reserve						
108	Transmission Depreciation Reserve	$0	$0	$0	10-AccDep, L. 212 and L. 312, col 13		108
109	Common + General + Intangible Depreciation Reserve	#DIV/0!	#DIV/0!	#DIV/0!	10-AccDep, L. 401 , col 4 and col 5		109
110	**Total Accumulated Depreciation Reserve**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	Line 108 + Line 109		110
111	**Accumulated Deferred Income Taxes**	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 111c		111
112	**Customer Advances**	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 112		112
113	**Unfunded Reserves**	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 113		113
114	**Other Regulatory Assets or Liabilities**	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 114		114
115	**CWIP Incentive**	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 115		115
116	**Rate Base**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	Sum of Lines 103, 107, 110 and Lines 111 to 115		116

Prior Year Transmission Revenue Requirement

Line	Description	High Voltage	Low Voltage	Total	Reference	Notes	Line
200	O&M Expense	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * (18-OandM, L. 100, col 15 - L. 114, col 15)		**200**
200a	O&M Expense from Transmission of Electricity by Others			$0	WP_26-WholesaleTRRs, L. 100, Col 3 and Col 4		**200a**
201	A&G Expense	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 501		**201**
202	Network Upgrade Interest Expense	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 502		**202**
203	Depreciation Expense (incl. Common + General + Intangible)	#DIV/0!	#DIV/0!	#DIV/0!	11-Depreciation, (L. 100, col 13 + L. 200, col 4), (L. 101, col 13 + L. 200, Col 5)		**203**
204	Depreciation rate adjustment	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 504		**204**
205	Abandoned or Cancelled Projects Amortization Expense	$0	$0	$0	8-AbandonedProject, Lines 100 and 101, Col 7		**205**
206	Return on Capital	#DIV/0!	#DIV/0!	#DIV/0!	(Line 116 * 1-BaseTRR, L. 219) - (1-BaseTRR, L. 221 * 8-AbandonedProject, L. 100 and L. 101, col 11)		**206**
207	Other Taxes	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 507		**207**
208	Income Taxes	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 508		**208**
209	Revenue Credits	#DIV/0!	#DIV/0!	#DIV/0!	Negative, 20-RevenueCredits, L. 100, col 5 + L. 1001, col 3 and L. 100, col 6 + L. 1001, col 4.		**209**
210	NP&S Credit	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 510		**210**
211	Amortization and Regulatory Debits/Credits	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 511		**211**
212	**Total without FF, Uncollectibles, and South Georgia**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	Sum of Lines 200 to Line 211		**212**
213	**Total SFGR Tax and Franchise Fees**	#DIV/0!	#DIV/0!	#DIV/0!	Line 212 * (1-BaseTRR, L. 513 + L. 514)		**213**
214	Self-Insurance including SFGR tax and Franchise, w/o Uncollectibles	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 521		**214**
215	ITRR	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 601		**215**
216	True-up Adjustment	#DIV/0!	#DIV/0!	#DIV/0!	Line 1 * 1-BaseTRR, L. 602		**216**
217	**Wholesale Base TRRs**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	Sum of Lines 212 to Line 216		**217**
218	**Wholesale TRBAA**			$0			**218**
219	**Standby Revenue Credit**	#DIV/0!	#DIV/0!	#DIV/0!	Negative, Line 1 * (29-RetailRates-1, L. 118, col (A) * 50%		**219**
220	**Total Wholesale TRRs**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	Sum of Lines 217 to Line 219		**220**

Notes:

...

Schedule 27-WholesaleRates

Calculation of PG&E Wholesale Rates **Rate Year:**

Input cells are shaded gold

Line	Description	Values	Source	Notes	Line
	Calculation of High Voltage Access Charge				
100	High Voltage TRR	#DIV/0!	26-WholesaleTRRs, L. 220, col 1		**100**
101	Gross Load (MWh)	-	28-GrossLoad, L. 104 / 1000		**101**
102	**High Voltage Access Charge ($/MWh)**	**#DIV/0!**	Line 100 / Line 101		**102**
	Calculation of Low Voltage Access Charge				
200	Low Voltage TRR	#DIV/0!	26-WholesaleTRRs, L. 220, col 2		**200**
201	Gross Load (MWh)	-	28-GrossLoad, L. 104 / 1000		**201**
202	**Low Voltage Access Charge ($/MWh)**	**#DIV/0!**	Line 200 / Line 201		**202**

Notes:

...

Schedule 28-GrossLoad

Calculation of Gross Load at the CAISO Interface (Area Out) **Rate Year:**

Input cells are shaded gold

Instructions:

1) Input the gross load data and loss factor from the Gross Load Workpapers.

Line	Description	Values	Source	Notes	Line
100	Energy at generator (kWh)		WP_28-GrossLoad 1, L. 102, col 2		**100**
101	Energy loss factor area out		WP_28-GrossLoad 7, L. 102, col 4		**101**
102	Retail energy at local (area out) (kWh)	-	Line 100 * Line 101		**102**
103	Helms Pumped Storage: Pumping Load (10 Yr Avg) (kWh)		WP_28-GrossLoad 6, L. 110		**103**
104	**Gross Load at Area Out (kWh)**	**-**	Line 102 + Line 103		**104**
105	**Gross Load Forecast was Approved on:**				**105**

Notes:

...

Schedule 29-RetailRates-1
Proposed Retail Rates
Rate Design
Input cells are shaded gold

Current Year for Forecast Billing Determinants
5 Yr. Historical Avg. Data for 12-CP Allocation of TRR to Customer Class

Line	Code	Class Name	Col 1 Note 1 Adjusted 12-CP Cost Allocation	Col 2 Note 2 Forecast Billing Determinants	Billing Units	Col 3 = col 1/col 2 Retail Rate	Billing Units	Col 4 Note 3 Annual Sales (kWh)	Col 5 = col 1/col 4 Average Rate ($/kWh)	Line
100	RES-	**Residential**	#DIV/0!	0	kWh	**#DIV/0!**	**/kWh**	0	#DIV/0!	100
101	A1/B1-	**Small L&P**	#DIV/0!	0	kWh	**#DIV/0!**	**/kWh**	0	#DIV/0!	101
102	A10/B10-	Medium L&P			kW-mo			0	#DIV/0!	102
103	E19/B19-	At Transmission			kW-mo			0	#DIV/0!	103
104	E19/B19-	At Primary			kW-mo			0	#DIV/0!	104
105	E19/B19-	At Secondary			kW-mo			0	#DIV/0!	105
106	**Medium Light and Power**		#DIV/0!	0	kW-mo	**#DIV/0!**	**/kW-mo**			106
107	STL-	**Streetlights**	#DIV/0!	0	kWh	**#DIV/0!**	**/kWh**	0	#DIV/0!	107
108	AGA-	AG: A Schedules		0	kWh			0	#DIV/0!	108
109	AGB/C-	AG: B Schedules		0	kWh			0	#DIV/0!	109
110	**Agriculture**		#DIV/0!	0	kWh	**#DIV/0!**	**/kWh**			110
111	E20/B20-	At Transmission			kW-mo			0	#DIV/0!	111
112	E20/B20-	At Primary			kW-mo			0	#DIV/0!	112
113	E20/B20-	At Secondary			kW-mo			0	#DIV/0!	113
114	**Schedule E-20**		#DIV/0!	0	kW-mo	**#DIV/0!**	**/kW-mo**			114

115	STB/SB-	At Transmission			kW-mo		0	#DIV/0!	115
116	STB/SB-	At Primary			kW-mo	50% Volumetric Charge	0	#DIV/0!	116
						#DIV/0! /kWh			
117	STB/SB-	At Secondary			kW-mo	50% Reservation Charge	0	#DIV/0!	117
						#DIV/0! /.85*kW-mo			
118	**Standby Service**		#DIV/0!	0	kW-mo		0	#DIV/0!	118
119	**Total**	Rate Design:	**#DIV/0!**				0	#DIV/0!	119

Notes:

1) Adjusted 12-CP Cost Allocations are from 29-RetailRates-2, col 8.

2) Forecast kWh Billing Determinates are from 29-RetailRates-2, col 2. Forecast kW-mo. Billing Determinants are detailed in WP_29-RetailRates 8 (A-10, E-19, E-20 and Standby Reservation).

3) Forecast kWh Annual Sales are from 29-RetailRates-2, col 2.

...

Schedule 29-RetailRates-2
Proposed Allocations & Revenues
Rate Design Calculations Based on 12-CP Method
Input cells are shaded gold

Current Year for Forecast Billing Determinants
5 Yr. Historical Avg.

Line	Code	Class Name	Col 1 Note 1 Recorded Avg. 5-Year Historical (kWh)	Col 2 Note 2 Forecast Sales (kWh)	Col 3 Note 3 Recorded Avg. 5-Year Historical (kW)	Col 4 = (col 2/col 1) * col 3 Coincident Demands Scaled to (kW)	Col 5 Note 4 Demand Loss Factors	Col 6 = col 4 * col 5 Coincident Demands (adjusted for losses) (kW)	Col 7 = col 6/ sum col 6 Percent of Coin. Peak (w/losses)	Col 8 Adjusted Cost Alloc. Factors (w/standby) scale to 100%	Col 9 = col 7 * TRR Adjusted 12-CP Cost Allocation ($)	Line
100	RES-	Residential				#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!	**#DIV/0!**	**100**
			MARL Sales:									
101	A1/B1-	Small L&P				#DIV/0!	0.00000	#DIV/0!	#DIV/0!	#DIV/0!	**#DIV/0!**	**101**
102	A10/B10-	Medium L&P				#DIV/0!	0.00000	#DIV/0!				**102**
103	E19/B19-	At Transmission				#DIV/0!		#DIV/0!				**103**
104	E19/B19-	At Primary				#DIV/0!		#DIV/0!				**104**
105	E19/B19-	At Secondary				#DIV/0!	0.00000	#DIV/0!				**105**
106	Medium Light and Power		0	0	0	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!	**#DIV/0!**	**106**
107	STL-	Streetlights				#DIV/0!	0.00000	#DIV/0!	#DIV/0!	#DIV/0!	**#DIV/0!**	**107**
108	AGA-	AG: A Schedules				#DIV/0!	0.00000	#DIV/0!				**108**
109	AGB/C-	AG: B Schedules				#DIV/0!	0.00000	#DIV/0!				**109**
110	Agriculture		0	0	0	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!	**#DIV/0!**	**110**
111	E20/B20-	At Transmission				#DIV/0!	0.00000	#DIV/0!				**111**
112	E20/B20-	At Primary				#DIV/0!	0.00000	#DIV/0!				**112**
113	E20/B20-	At Secondary				#DIV/0!	0.00000	#DIV/0!				**113**
114	Schedule E-20/B-20		0	0	0	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!	**#DIV/0!**	**114**
115	**Total - Full Requirements**		**0**	**0**	**0**	**#DIV/0!**		**#DIV/0!**	**#DIV/0!**	**100.00%**	**#DIV/0!**	**115**
116	STB/SB-	At Transmission				#DIV/0!	0.00000	#DIV/0!				**116**
117	STB/SB-	At Primary				#DIV/0!	0.00000	#DIV/0!				**117**
118	STB/SB-	At Secondary				#DIV/0!	0.00000	#DIV/0!				**118**
119	Standby		0	0	0	#DIV/0!		#DIV/0!			**#DIV/0!**	**119**
120	**Totals - Retail**		**0**	**0**	**0**	**#DIV/0!**		**#DIV/0!**		**100.00%**	**#DIV/0!**	**120**
121	**Source: Base Transmission Revenue Requirement (TRR) 1-BaseTRR, L. 704 =**										**#DIV/0!**	**121**

Notes:

1) Recorded sales (kWh) and 5-Year Average are from WP_29-RetailRates 4; 5; and 5a.
2) Forecast kWh Billing Determinates are from WP_29-RetailRates 8 and 9 and approved by the CPUC in D.19-02-023.
3) Recorded monthly contribution coincident system peak (12-CP) data (kW) and 5-Year Average are from WP_29-RetailRates 3; 3a; and 4.
4) Demand loss factors are based on system losses at PG&E's Transmission, Primary and Secondary Distribution voltage levels of service.

5) Medium Light and Power Line 106 is a subtotal of Lines 102 through 105; Agriculture Line 110 is a subtotal of Lines 108 and 109; Schedule E-20 Line 114 is a subtotal of Lines 111 through 113; Total - Full Requirements Line 115 is a subtotal of Lines 100, 101, 106, 107, 110 and 114; Standby Line 119 is a subtotal of Lines 116 through 118; Totals - Retail Line 120 is a total of Line 115 and 119.

...

Schedule 30-WFSelfInsurance
Wildfire Self-Insurance
Input cells are shaded gold

Rate Year:
Prior Year: -2

Rate Year Electric Transmission Network Wildfire Self-Insurance Revenue Requirement

Line	Col 1 Description	Col 2 Amount	Col 3 Source	Line
	Wildfire Self-Insurance Initial Funding- See Note 1			
100	Annual Wildfire Self-insurance Initial Funding on Electric Basis		WP_30-WFSelfInsurance 1, Line 100	**100**
101	Network Transmission Plant Factor (Total Electric)	#DIV/0!	24-Allocators, Line 119	**101**
102	Electric Transmission Network Wildfire Self-insurance Initial Funding	#DIV/0!	Line 100 * Line 101	**102**
	Wildfire Self-Insurance Initial Funding Catch Up Related to 2024 Suspension, If Applicable- See Note 2			
103	Annual Wildfire Self-insurance Initial Funding on Electric Basis	$ -	TO21 RY 2024, Schedule 30-WFSelfInsurance, Line 100, Col 2	**103**
104	Number of months of Suspension	-		**104**
105	Network Transmission Plant Factor (Total Electric)	#DIV/0!	24-Allocators, Line 119	**105**
106	Electric Transmission Network Wildfire Self-Insurance Initial Funding Catch Up Related to 2024 to be included in 2025 Rates	#DIV/0!	Line 103 / 12 * Line 104 * Line 105	**106**
107	**Total Electric Transmission Network Wildfire Self-Insurance Initial Funding**	#DIV/0!	Line 102 + Line 106	**107**
	Wildfire Self-Insurance Replenishment Funding			
200	Prior Year wildfire injuries and damages expenses covered by wildfire self-insurance on electric basis	$ -		**200**
201	Prior Year wildfire related outside legal fees covered by wildfire self-insurance on electric basis	$ -		**201**
202	Other Prior Year applicable self-insurance costs on electric basis - See Note 3	$ -	WP_30-WFSelfInsurance 1, Line 300, Col 3	**202**
203	Less: Deductible on electric basis (shows as negative #)	$ -	WP_30-WFSelfInsurance 1, Line 400, Col 2	**203**
204	Net Prior Year wildfire liability related expenses on electric basis	$ -	Lines 200 + 201 + 202 + 203	**204**
205	Network Transmission Plant Factor (Total Electric)	#DIV/0!	24-Allocators, Line 119	**205**
206	Net Electric Transmission Network share of wildfire liability related expenses	#DIV/0!	Line 204 * Line 205	**206**
207	Less: Investment income, net of fees, allocated to electric transmission network (show as negative #), including carry over amounts not previously included in determining replenishment funding - See Note 4	$ -	WP_30-WFSelfInsurance 1, Line 214, Col 6	**207**
208	Calculated Electric Transmission Network wildfire self-insurance replenishment funding	#DIV/0!	Line 206 + Line 207	**208**
209	**Final Rate Year Electric Transmission Network Wildfire Self-Insurance Replenishment Funding**	#DIV/0!	If Line 208 > $0, Line 209 = Line 208. If Line 208 < or = $0, Line 209 = $0.	**209**

Notes:

1	The initial wildfire funding contribution in 2024 and 2025 to achieve electric transmission network's share of the $1 billion of available wildfire self-insurance over two years.
2	2024 initial wildfire funding contribution catch up in 2025 for electric transmission network's share of wildfire self-insurance initial funding if FERC suspends the TO21 Formula Rate beyond January 1, 2024.
3	Other applicable self-insurance costs refer to costs that are reimbursable under regular commercial policies but not recorded in Account 923 and 925.
4	The monthly total investment income earned for the captive will be allocated to CPUC and FERC jurisdictional customers based on their respective self-insurance balance at the beginning of the month in the captive.
...	...

Schedule 31-COO
Cost of Ownership Rates **Rate Year:**
Input cells are shaded gold

1) Monthly Cost of Ownership Rates

Line			Source	Line
100	**Monthly Customer Financed Cost of Ownership Rate:**	**#DIV/0!**	Line 216	100
101	**Monthly Utility Financed Cost of Ownership Rate:**	**#DIV/0!**	Line 310	101

2) Calculation of the Customer Financed Cost of Ownership Rates

Line	Description	Values	Source	Line
200	Total Transmission O&M	#DIV/0!	1-BaseTRR, Line 500	200
201	Total A&G Excluding Franchise Expense	#DIV/0!	1-BaseTRR, Line 501	201
202	Total Other Taxes (Property, Payroll, and Business)	#DIV/0!	1-BaseTRR, Line 507	202
203	Total Self-Insurance w/o SFGR Tax and Franchise Tax	#DIV/0!	1-BaseTRR, Line 519	203
204	Total Network Transmission CGI Depreciation Expense	#DIV/0!	11-Depreciation, Line 200, Col 3	204
205	Return	#DIV/0!	1-BaseTRR, Line 506	205
206	Federal and State Income Tax Allowable	#DIV/0!	1-BaseTRR, Line 508	206
207	Total Transmission Return and Income Tax	#DIV/0!	Line 205 + Line 206	207
208	Gross Transmission General and Common Plant	#DIV/0!	1-BaseTRR, Line 101	208
209	Total Gross Transmission Plant in Service including CGI	#DIV/0!	1-BaseTRR, Line 103	209
210	Transmission General and Common Plant Return and Income Tax	#DIV/0!	Line 207 * (Line 208 / Line 209)	210
211	Transmission Revenue Requirement with Capital Contribution w/o Franchise & SFGR Tax Requirement	#DIV/0!	Sum of Lines 200 through Line 204 + Line 210	211
212	Franchise & SFGR Tax Requirement	#DIV/0!	Line 211 * (1-BaseTRR, Line 513 + 1-BaseTRR, Line 514)	212
213	Transmission Revenue requirement with Capital Contribution and Franchise & SFGT Tax Requirement	#DIV/0!	Line 211 + Line 212	213
214	Transmission Functional Gross Plant	$0	1-BaseTRR, Line 100	214
215	Annual Transmission Carrying Percentage with Capital Contribution and Franchise Fee and SFGR Tax Requirement	#DIV/0!	Line 213 / Line 214	215
216	Monthly Transmission Carrying Percentage with Capital Contribution and Franchise & SFGR Tax Requirement	#DIV/0!	Line 214 / 12 months	216

3) Calculation of the Utility Financed Cost of Ownership Rates

Line	Description	Values	Source	Line
300	Total Transmission O&M	#DIV/0!	1-BaseTRR, Line 500	300
301	Total A&G Excluding Franchise Expense	#DIV/0!	1-BaseTRR, Line 501	301
302	Total Other Taxes (Property, Payroll, and Business)	#DIV/0!	1-BaseTRR, Line 507	302
303	Total Self-Insurance w/o SFGR Tax and Franchise Tax	#DIV/0!	1-BaseTRR, Line 519	303
304	Total Network Transmission Depreciation Expense including CGI	#DIV/0!	1-BaseTRR, Line 503 + 1-BaseTRR, Line 504	304
305	Return	#DIV/0!	1-BaseTRR, Line 506	305
306	Federal and State Income Tax Allowable	#DIV/0!	1-BaseTRR, Line 508	306
307	Franchise & SFGR Tax Requirement	#DIV/0!	Sum of Lines 300 through Line 306 * (1-BaseTRR, Line 513 + 1-BaseTRR, Line 514)	307
308	Transmission Functional Gross Plant	$0	1-BaseTRR, Line 100	308
309	Annual Transmission Carrying Percentage without Capital Contribution	#DIV/0!	Sum of Lines 300 through Line 307 / Line 308	309
310	Monthly Transmission Carrying Percentage without Capital Contribution	#DIV/0!	Line 309 / 12 months	310

Notes:

...

Schedule 32-CWIPIncentive
CWIP Incentive - Recorded CWIP for Projects Approved for CWIP Incentive **Prior Year: -2**
Input cells are shaded gold

This Schedule presents the amount of prior year (and December of prior year minus 1) Construction Work in Progress (CWIP) for projects that have received Commission approval to include CWIP in Rate Base.

1) Prior Year (and December of prior year minus 1) Monthly Ending CWIP included in Rate Base
Recorded CWIP balances are extracted from Powerplan, PG&E's fixed asset system of record, by querying by Planning Order or other criteria.
PG&E will add additional rows as needed.

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14	Col 15	Col 16	Col 17	
				-3	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	13-Month	
Line				Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average	Line
100			Total Eligible CWIP (from below):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	100
				-3	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2	-2		
	Project	Description	% of CWIP Eligible	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
200	...	...																200
201	...	...																201

Notes:

...

APPENDIX X:
LETTER AGREEMENT

APPENDIX X
LETTER AGREEMENT

[Date]

[Authorized Representative Name]
[Title]
[Company]
[Address]

Re: Letter Agreement for the **[Project Name]** Project **[Project ID:]** located at **[lat/long or street, city, zip and county]**

Dear Mr./Ms. **[Authorized Representative Last Name]**:

Pacific Gas and Electric Company ("PG&E") hereby enters into this Letter Agreement ("Agreement") with **[Interconnection Customer Name]** for certain work prior to the execution of the applicable Generator Interconnection Agreement ("IA") under the terms of PG&E's Transmission Owner (TO) Tariff. The Interconnection Customer is an Eligible Customer as that term is defined in the TO Tariff.

All capitalized terms used herein, and not otherwise defined, shall have the meaning ascribed to that term in PG&E's TO Tariff. The Interconnection Customer and PG&E are sometimes referred to herein individually as "Party" and collectively as "Parties."

In the interest of working towards the achievement of the Interconnection Customer's expected operating date, as set forth in Exhibit D (Milestones), the Interconnection Customer desires for PG&E to commence certain work prior to executing the IA. Accordingly, the purpose of this letter agreement ("Agreement") is to agree upon an interim arrangement pursuant to which PG&E will commence, and the Interconnection Customer will pay for, the Work described herein, according to the following terms and conditions:

1. **Work**. PG&E will perform the Work, as described in Exhibit A, upon payment of amounts described in Section 2 and according to the terms provided herein. PG&E shall perform the Work only after receipt of the payments and financial security set forth in Exhibit C, as may be modified by Section 2.2. The Interconnection Customer acknowledges and understands that completion of the Interconnection Studies, if applicable, may identify required Network Upgrades and/or additional or modified Interconnection Facilities and Distribution Upgrades necessary to enable operation of the Project at the full net output and understands that any such Network Upgrades and/or

additional Interconnection Facilities and Distribution Upgrades will be included in the IA as a required scope to allow full operation of the Project.

2. Payments and Financial Security.

2.1. **Payments/Security.** For PG&E to perform its obligations under the terms and conditions of this Agreement, the Interconnection Customer shall provide to PG&E the payments and financial security, in such estimated amounts as set forth in Exhibits B and C (as may be modified as described in Section 2.2) and in such form and on such dates as set forth in Exhibit C. PG&E will provide the Interconnection Customer an invoice of such payment obligations, which must be paid by the payment dates in Exhibit C.

2.2. **Additional Amounts**. PG&E shall notify Interconnection Customer in writing within a reasonable time if PG&E learns that charges and expenses are likely to exceed the estimated amounts specified in Exhibit B, warranting adjustments to amounts in Exhibit C. The Parties will agree to amend this Agreement in order to reflect and collect the additional amounts required, subject to Federal Energy Regulatory Commission ("FERC") approval, as applicable, before an invoice for the additional amounts or a request to increase the financial security is issued to the Interconnection Customer.

For Network Upgrades, such additional amounts will not result in costs exceeding the Interconnection Customer's maximum cost responsibility identified in the Interconnection Studies, which may be modified in subsequent reassessments.

In the event of such notification, PG&E shall specify the additional payment and/or the corresponding financial security increase(s) and Interconnection Customer shall:

2.2.1 Pay such additional invoiced amounts within thirty (30) Calendar Days from the date of the invoice.

2.2.2 Post an increase to the financial security amount within thirty (30) Calendar Days of such request.

2.3. **Failure to Pay; Insolvency**. Subject to Section 3.2, in the event that the Interconnection Customer fails to provide payment for amounts incurred or irrevocably committed to be incurred, or fails to provide financial security, pursuant to this Agreement, PG&E may (a) immediately stop Work; (b) draw on the Interconnection Financial Security for any amounts due to PG&E during the term of this Agreement, and/or (c) terminate this Agreement by written notice of cancellation effective upon FERC approval. In the event that Interconnection Customer (i) is dissolved; (ii) becomes insolvent; (iii) becomes the subject of a petition in bankruptcy, either voluntary or involuntary, or in any other proceeding under federal bankruptcy laws; (iv) makes an assignment for the benefit of creditors, excluding any assignment for financing purposes; (v) is named in a suit for the appointment of a receiver, PG&E may, in addition to (a) through (c) above, draw on any tax security for any tax liability imposed on PG&E during the term of this Agreement.

3. **Dispute.** Disputes arising out of or in connection with this Agreement shall be resolved as follows:

3.1. **Submission.** In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this Agreement or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this Agreement.

3.2. **Payment Dispute.** In the event of a billing dispute between PG&E and the Interconnection Customer, PG&E shall continue to perform the Work under this Agreement as long as the Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to PG&E or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Interconnection Customer fails to meet these two requirements for continuation of service, then PG&E may invoke remedies in Section 2.3. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accordance with the methodology set forth in FERC's Regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

3.3. **External Arbitration Procedures.** Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations; provided, however, in the event of a conflict between the Arbitration Rules and the terms of Section 3, the terms of this Section 3 shall prevail.

3.4. **Arbitration Decisions.** Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator also must be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, Distribution Upgrades, or Network Upgrades.

3.5. **Costs.** Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three-member arbitration panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

4. **Milestone Schedule.** The milestone schedule is attached as Exhibit D. PG&E shall use commercially reasonable efforts to complete the Work in accordance with this schedule. However, PG&E does not warrant the Work will be completed in time to meet such deadlines, and the Interconnection Customer understands and acknowledges that such deadlines are only estimates and that the due dates in Exhibit D are dependent on Interconnection Customer coordinating with PG&E to complete the milestones as specified in a timely manner. PG&E shall not be liable for any cost or damage incurred by the Interconnection Customer as a result of or due to any delay in the completion of the Work pursuant to the milestone schedule.

5. **Termination.**

5.1. Except for terms that survive termination, this Agreement shall terminate upon the earliest of the following to occur: (i) notice that this Agreement is not accepted for filing by FERC, if applicable; (ii) the effective date of the IA, which the Parties intend to supersede this Agreement; (iii) the Interconnection Customer's receipt of PG&E's notice of cancellation pursuant to Section 2.3, which is subject to acceptance by FERC; (iv) two (2) Business Days after receipt by PG&E of a termination notice from Interconnection Customer to PG&E at any time and for any reason; or (v) withdrawal of the Interconnection Customer's Interconnection Request for the Project.

5.2. In the event that either Party terminates this Agreement for reasons other than the execution of the IA, PG&E shall use commercially reasonable efforts to mitigate the costs, damages, and charges arising as a consequence of such termination. To that end, PG&E shall cancel, to the extent possible, or return any pending orders of any materials or equipment procured pursuant to this Agreement. To the extent that the Interconnection Customer already has paid PG&E for any or all costs of such materials, equipment or contracts cancelled or returned, PG&E shall refund such amounts to Interconnection Customer, less any costs or penalties incurred by PG&E to cancel pending orders for or return of such materials and equipment.

5.3. In the event that this Agreement is terminated or if the Work is completed before the effective date of the IA and a payment shortfall exists pursuant to Section 5.3.2 of this Agreement, PG&E shall make reasonable efforts to submit a final invoice to Interconnection Customer of all charges and expenses within twelve (12) months from the date of termination of or completion of the Work performed under this Agreement. In such event, the following true-up process will be used:

5.3.1. **Payment Excess.** In the event that the Interconnection Customer's payment(s) paid in accordance with this Agreement exceeds the amount of PG&E's charges and expenses incurred or irrevocably committed to be incurred pursuant to this Agreement, PG&E shall return the excess amount without interest to Interconnection Customer within thirty (30) Calendar Days after the final reconciliation for this work is completed without offset for any amount that may be in dispute. For Network Upgrades, any refundable payment amount will be made in accordance with the GIDAP.

5.3.2. **Payment Shortfall.** In the event that Interconnection Customer's payment(s) paid in accordance with this Agreement is less than the amount of PG&E's charges and expenses incurred or irrevocably committed to be incurred pursuant to this Agreement, then the Interconnection Customer shall pay the difference, without interest, within thirty (30) Calendar Days after the final reconciliation for this work is completed, without offset for any amount which may be in dispute. If Interconnection Customer fails to pay the final invoice, PG&E also shall have the right to draw on the Interconnection Financial Security for any payment shortfall. For Network Upgrades, the Interconnection Customer will be invoiced and/or PG&E shall have the right to draw on the Interconnection Financial Security for any payment shortfall up to the Interconnection Customer's maximum cost responsibility.

5.4. In the event that the Interconnection Customer elects to terminate this Agreement but still take delivery of materials or equipment procured pursuant to this Agreement, the Interconnection Customer shall assume all payment obligations with respect to delivery of such materials, equipment, and contracts, and PG&E shall transfer such materials and equipment, and, if necessary, assign such contracts, to the Interconnection Customer as soon as reasonably practicable, at the Interconnection Customer's expense.

5.5. In the event that the Interconnection Customer and PG&E enter into an IA concurrently with the termination of this Agreement, then any applicable work product generated by PG&E and any associated payments made by Interconnection Customer pursuant to this Agreement not already credited shall be reflected in the scope of, and the amount due under, such IA.

6. Taxes.

6.1. The Parties intend that all payment(s) made by the Interconnection Customer to PG&E pursuant to this Agreement shall be non-taxable in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal

Revenue Code and any applicable state income tax laws. The Interconnection Customer shall protect, indemnify and hold harmless PG&E from the cost consequences of any income tax liability imposed against PG&E as the result of payment(s) made by the Interconnection Customer to PG&E under this Agreement, as well as any interest and penalties.

6.2. If PG&E or the IRS makes a determination that the payment(s) made pursuant to this Agreement are taxable as contributions in aid of construction, either: (i) PG&E may request the financial security from the Interconnection Customer for the estimated tax liability held on behalf of the Project to pay the tax liability imposed on PG&E; or (ii) Interconnection Customer may elect to make a nonrefundable cash payment to PG&E within thirty (30) Calendar Days of receipt of the invoice in the actual amount of the resultant tax liability. The tax liability will be calculated using the methodology described in Article 5.17.4 (Tax Gross- Up Amount) of the Large Generator IA and in accordance with IRS Notice 2016-36.

7. **Force Majeure.** No Party shall be considered to be in default with respect to any obligation hereunder, other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure (as defined in the IA), which for purposes of clarity shall include pandemic. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Section 7 shall be confirmed in writing as soon as reasonably possible and shall specifically state the full particulars of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

8. **Indemnity.** Each Party shall at all times indemnify, defend, and hold the other Party harmless from any and all Losses arising out of or resulting from the other Party's action or inactions with respect to its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

9. **Consequential Damages.** In no event shall any Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, or cost of temporary equipment or services, whether based in whole or in part in contract or in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

10. **Entire Agreement.** This Agreement, including all Exhibits attached hereto, constitutes the complete and final expression of the agreement between the Parties and is intended as a complete and exclusive statement of the terms of their agreement. This Agreement

supersedes all prior and contemporaneous offers, promises, representations, negotiations, discussions, communications, and other agreements, which may have been made in connection with the subject matter of this Agreement. Nothing in this Agreement is intended or shall be deemed to require PG&E or Interconnection Customer to enter into any other agreement, including without limitation any agreement to interconnect the Project. Should the Parties enter into an IA, such IA will supersede this Agreement.

11. **Insurance.** Each Party shall maintain insurance coverage consistent with the requirements as set forth in the *pro forma* IA.

12. **Access Rights**. Each Party shall provide access rights consistent with the requirements as set forth in the *pro forma* IA.

13. **Waiver.** Any waiver at any time by either Party of its rights with respect to this Agreement, shall not be deemed a waiver with respect to any other failure to comply with any obligation, right or duty of this Agreement. Any delay, with the exception of the statutory period of limitation in assessing or enforcing any right, shall not be deemed a waiver of such right.

14. **No Joint Liability.** The covenants, obligations, and liabilities of the Parties are intended to be several and not joint or collective, and nothing contained in this Agreement shall ever be construed to create an association, joint venture, trust, or partnership, or to impose a trust or partnership covenant, obligation, or liability on or with regard to either Party. Each Party shall be individually responsible for its own covenants, obligations, and liabilities as provided in this Agreement. Neither Party shall be under the control of the other Party. Neither Party shall be the agent of or have a right or power to bind the other Party without such other Party's express written consent.

15. **No Third Party Beneficiaries.** The Parties do not intend to create rights in, or to grant remedies to, any third party as a beneficiary either of this Agreement or of any duty, covenant, obligation, or undertaking established herein.

16. **Governing Law.** This Agreement shall be interpreted by and in accordance with the laws of the State of California, without regard to the principles of conflict of laws therefor, or the laws of the United States, as applicable, as if executed and to be performed wholly within the United States.

17. **Successors and Assigns.** This Agreement shall be binding upon the Parties and their successors and assigns. This Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Section will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will

notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Section is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

18. **Survival.** Indemnity obligations and obligations to pay charges and expenses incurred or irrevocably committed to be incurred pursuant to this Agreement will survive termination of this Agreement.

19. **FERC Filing.** PG&E will report this Agreement and amendments thereto in its Electronic Quarterly Report ("EQR") in lieu of filing it at FERC, pursuant to Applicable Laws and Regulations.

20. **Reservation of Rights.** PG&E shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

21. **Construction.** Ambiguities or uncertainties in the wording of this Agreement shall not be construed for or against any Party but shall be construed in the manner that most accurately reflects the Parties' intent as of the date they executed this Agreement.

22. **Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by all the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

23. **Confidentiality.** The provisions governing confidentiality in the *pro forma* IA are hereby incorporated herein, in their entirety.

24. **Authority.** Each Party hereby represents that it and its signatory below have the right, power, and authority to enter into this Agreement, to become a Party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

25. **Warranties.** The Interconnection Customer warrants that it is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it is qualified to do business in the state or states in

which the Facility is located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

26. **Headings.** The descriptive headings of the various Sections of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

27. **Execution.** This Agreement may be executed in two or more counterparts, each of which is deemed an original, but all constitute one and the same instrument.

28. **Effective Date.** This Agreement shall become effective upon execution by all Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC.

PACIFIC GAS AND ELECTRIC COMPANY

By____/s/ [Signature]_____
Name: **[Name]**
Title: **[Title]**

ACCEPTED AND AGREED to this _____ day of ________________ 20_____

[IC COMPANY NAME]

By____/s/ [Signature]_____
Name: **[Name]**
Title: **[Title]**

ACCEPTED AND AGREED to this _____ day of ________________ 20_____

EXHIBIT A

SCOPE OF WORK

[PG&E to insert a description of the Work to be performed by PG&E, including work related to Interconnection Facilities, Transmission Upgrades, and Network Upgrades, as applicable. A one-line diagram of the interconnection may be included, if applicable.]

EXHIBIT B

ESTIMATED COST OF THE WORK AND FINANCIAL SECURITY

[PG&E will provide an estimated cost of the Work identified in Exhibit A and any associated financial security, including Interconnection Financial Security and tax security*.]

*The rate(s) applicable to any tax security is in accordance with PG&E's Transmission Owner Tariff designated as FERC Electric Tariff, Volume No. 5 as such tariff may be amended or superseded.

Additional Definitions:

Distribution Upgrades Cost: The Interconnection Customer's allocated share of all costs determined by PG&E to be associated with the design, engineering, procurement, construction and installation of the Distribution Upgrades.

Interconnection Facilities Cost: All costs determined by PG&E to be associated with the design, engineering, procurement, construction and installation of Participating TO's Interconnection Facilities.

Local Delivery Network Upgrades Cost: The Interconnection Customer's allocated share of all costs determined by PG&E to be associated with the design, engineering, procurement, construction and installation of the Local Delivery Network Upgrades constructed and owned by PG&E.

Local Off-Peak Network Upgrades Cost: The Interconnection Customer's allocated share of all costs determined by PG&E to be associated with the design, engineering, procurement, construction and installation of the Local Off-Peak Network Upgrades constructed and owned by PG&E.

Reliability Network Upgrades Cost: The Interconnection Customer's allocated share of all costs determined by PG&E to be associated with the design, engineering, procurement, construction and installation of Reliability Network Upgrades.

a. Estimated Cost

[PG&E to provide a description of these activities to be performed under this Letter Agreement, as applicable, along with a cost table summarizing the estimated costs for those activities.]

Element	Interconnection Facilities Cost ($)	Distribution Upgrades Cost ($)	Reliability Network Upgrades Cost ($)	Local Delivery Network Upgrades Cost ($)	Local Off-Peak Network Upgrades Cost ($)	Total ($)

[Rows to include description of the elements of the scope of work and estimated costs]						
Total	**$ xxxxxx**	**$ xxxxxx**	**$ xxxxxx**	**$ xxxxxx**	**$ xxxxxx**	**$ xxxxxx**

b. Financial Security

[PG&E to insert information about financial security(-ies) required to support the work described above.]

EXHIBIT C

PAYMENT AND FINANCIAL SECURITY SCHEDULE

[PG&E will include a schedule(s) of the amount, and due date, for the payments and financial security, as applicable, identified in Exhibit B.]

EXHIBIT D

MILESTONES

[As needed, PG&E will include a list of relevant milestones applicable only to the Work to be completed under this Letter Agreement.]