SAN DIEGO GAS & ELECTRIC COMPANY

TRANSMISSION OWNER TARIFF

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1. **Preamble.** The Participating TO’s revenue requirements and applicable rates and charges for transmission access 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, such 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.
2. **Effective Date.** This TO Tariff will not be effective until all of the following conditions have been met:

2.1 **Adverse Determinations.** FERC has made this TO Tariff effective with no material conditions unacceptable to the Participating TO.

2.2 **Necessary Regulatory Approvals.** The Participating TO has received all necessary regulatory approvals to transfer control of facilities to and participate in the ISO.
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 to the ISO by all UDCs, MSSs and, in certain cases, Scheduling Coordinators, delivering Energy to Gross Load, as set forth in Section 7.1 of the ISO Tariff. The Access Charge includes the High Voltage Access Charge, the Transition Charge, and the Low Voltage Access Charge.

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, Replacement 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 the Transmission Revenue Balancing Account Adjustment (TRBAA) and Standby Transmission Revenues.

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
3.10 **Completed Interconnection Application.** (continued)
the TO Tariff and, if applicable, the information requirements as specified by
the ISO and posted on the ISO Home Page.

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 as defined in Section
2.4.4.2.1 of the ISO Tariff.

3.14 **CPUC.** The California Public Utilities Commission, or its successor.
3.15 **Delivery Upgrade.** The transmission facilities, other than Direct Assignment Facilities and Reliability Upgrades, necessary to relieve constraints on the ISO Controlled Grid and to ensure the delivery of energy from a New Facility to Load.

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 or 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
3.20 **Eligible Customer.** (continued)

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 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 **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 MWh, etc.

3.24 **Entitlements.** The right of the Participating TO obtained through contract or other means to use another entity’s transmission facilities for the transmission of Energy.

3.25 **Existing Contracts.** The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contacts 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.
3.26 **Existing Rights.** Those transmission service rights defined in Section 2.4.4.1.1 of the ISO Tariff.

3.27 ** Expedited Interconnection Agreement.** A contract between a party which has submitted a Request for Expedited Interconnection Procedures and the Participating TO to agree 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.

3.28 **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.
3.29 **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.

3.30 **FERC.** The Federal Energy Regulatory Commission, or its successor.

3.31 **FPA.** Parts II and III of the Federal Power Act, 16 U.S.C. § 824 et seq., as they may be amended from time to time.

3.32 **FTR (Firm Transmission Right).** A contractual right, subject to the terms and conditions of the ISO Tariff, that entitles the FTR Holder to receive, for each hour of the term of the FTR, a portion of the Usage Charges received by the ISO for transportation of energy from a specific originating Zone to a specific receiving Zone and, in the event of an uneconomic curtailment to manage Day-Ahead congestion, to a Day-Ahead scheduling priority higher than that of a schedule using Converted Rights capacity that does not have an FTR.
3.33 **FTR Holder.** The owner of an FTR, as registered with the ISO.

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...
3.36 **Good Utility Practice.** (continued)

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.** Gross Load is 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-User Customer of the Participating TO that is served by a Generating Unit that: (a) is located on 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
3.37 **Gross Load.** (continued)

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 and assessed to the Participating TO under Section 7.1 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 is represented by a Converted right and that 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 forecasted Gross Load.

3.42 **High Voltage Wheeling Access Charge.** The Wheeling Access Charge assessed by the ISO associated with the recovery of the Participating TOs’ High Voltage Transmission Revenue Requirements in accordance with Section 7.1 of the ISO Tariff.

3.43 **Inter-Zonal Interface.** The (i) group of transmission paths between two adjacent Zones of the ISO Controlled Grid, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has
3.43 **Inter-Zonal Interface.** (continued)

been established or will be established prior to the use of the interface for Congestion Management; (ii) the group of transmission paths between an ISO Zone and an adjacent Scheduling Point, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; or (iii) the group of transmission paths between two adjacent Scheduling Points, where the group of paths has an established transfer capability and established transmission rights.

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) produced Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not
3.44 **Interconnection.** (continued)

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. §35.19(a)(2)(iii)(1996). 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, as 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 as Appendix L, promulgated by the ISO (as amended from time to time) to be complied with by the ISO Scheduling Coordinators, Participating
3.51 **ISO Protocols.** (continued)

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, and irrigation district furnishing electric services, or a joint powers authority that include 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 7.1 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 is 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 7.1 of the ISO Tariff.
3.63 **Market Participant.** An entity, including a Scheduling Coordinator, who participates in the Energy marketplace though 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 of a New Participating TO, located within a single Zone which has been operating for a number of years prior to the ISO Operations Date subsumed within the ISO Control 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 internal to the system, which is operated in accordance with an agreement described in Section 3.3.1 of the ISO Tariff.

3.65 **NERC.** The North American Electric Reliability Council or its successor.

3.66 **New Facility.** (a) Each generating unit that proposes to sell its Generation at wholesale that seeks to connect to the ISO Controlled Grid; (b) each existing generating unit directly interconnected to the ISO Controlled Grid that will be
3.66 **New Facility.** (continued)
repowered and increases the total capability of the power plant; or (c) each
existing generating unit directly interconnected to the ISO Controlled Grid that
will be repowered, increasing the total capability of the power plant but has
changed the electrical characteristics of the power plant such that its re-
energization may violate Applicable Reliability Criteria and require additional
Direct Assignment Facilities or Reliability Upgrades.

3.67 **New Facility Operator.** The owner of a planned New Facility, or its
designee.

3.68 **New High Voltage Transmission Facility.** A High Voltage Transmission
Facility of the Participating TO that enters service after the beginning of the
transmission period described in Section 4 of Schedule 3 of Appendix F of the
ISO Tariff, or a capital addition made after the beginning of the transition
period described in Section 4.1 of Schedule 3 of Appendix F of the ISO Tariff
to an Existing High Voltage Transmission Facility.
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 2.4.3 and 2.4.4 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.

3.71 **Non-Self-Sufficient Access Charge.** A charge for access to the ISO Controlled Grid, referenced in certain Existing Contracts to be paid by the Existing Contract holder to the Participating TO. The Participating TO’s non-self-sufficient contract demand rate shall be calculated by dividing the Base Transmission Revenue Requirement by the sum of the highest hourly system demand forecast to be delivered by the Participating TO to End-Use Customers connected to its transmission and distribution facilities for each month of the year used by the Participating TO for base transmission rate development.
3.72 **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.

3.73 **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.

3.74 **Original Participating TO.** A participating TO that was a Participating TO as of January 1, 2000. The Original Participating TO’s are Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.

3.75 **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
3.75 **Participating TO.** (continued)

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 San Diego Gas & Electric Company.

3.76 **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.

3.77 **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
3.77 **Physical Scheduling Plant.** (continued)

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.

3.78 **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 3.2 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 by Generating Units equipped and operating with AGC which will enable such units to respond to the ISO’s direct digital control signals in an upward and downward direction to match, on a real time basis, Demand and resources, consistent with established NERC and WSCC operating criteria. 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 areas within the predetermined limits.
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.** Those services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services include services obtained from Reliability Must Run units, local out of market dispatch calls, and generation committed pursuant to the ISO’s must-offer requirement when the unit is committed for local reliability. In addition, Reliability Services include services provided by the Participating TO as a result of its implementing procurement procedures that mitigate Intra-Zonal Congestion, as defined in the ISO tariff.

3.84 **Reliability Upgrade.** The transmission facilities, other than Direct Assignment Facilities, beyond the first point of Interconnection necessary to interconnect a New Facility or wholesale load safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the Interconnection of a New Facility or wholesale load, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a New Facility or wholesale load to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WSCC practice, the facilities necessary to mitigate any adverse impact a New
3.84 **Reliability Upgrade.** (continued)
Facility’s or 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 New Facility Operator or wholesale load and shall be subject to FERC approval.

3.85 **Replacement Reserve.** Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and ramping to a specified Load point within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.

3.86 **Request for Expedited Interconnection Procedures.** A written request by which an applicant for Interconnection can request expedited processing of its Interconnection Application.
3.87 **Scheduling Coordinator.** An entity certified by the ISO for the purposes of undertaking the functions specified in Section 2.2.6 of the ISO Tariff.

3.88 **Scheduling Point.** A location at which the ISO Controlled Grid 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. A Scheduling Point typically is physically located at an “outside” boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO’s Controlled Grid.

3.89 **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.
3.90 **Standby Rate.** 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, among other things for costs of High Voltage Transmission Facilities.

3.91 **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.

3.92 **Standby Service Customer.** A retail End-Use Customer of the Participating TO that receives Standby Service and pays a Standby Rate.
3.93 **Standby Transmission Revenue.** The transmission rate revenues associated with Standby Service collected by the Participating TO from those Standby Service Customers who are not billed for Standby Service on a Gross Load basis.

3.94 **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.

3.95 **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.

3.96 **Rate Effective Period.** The period during which transmission service rates calculated pursuant to the formula rate provisions contained in Appendix IX are effective. The initial Rate Effective Period shall be October 1, 2003, or such other date as may be provided by FERC, through June 30, 2004. Each subsequent Rate Effective Period shall be the twelve-month period from July 1 through June 30.

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Vice President, Regulatory Affairs

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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 **Transmission Access Charge Balancing Account Adjustment ("TACBAA").** A mechanism established by the Participating TO which will ensure that the difference between (i) the actual billings by the ISO pursuant to Section 7.1.2 of the ISO Tariff for the High Voltage Access Charge and Transition Charge and (ii) the revenues disbursed by the ISO pursuant to Section 7.1.3 of the ISO Tariff are recovered from the Participating TO’s End-Use Customers.

3.100 **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.
3.101 **Transmission Owner (“TO”).** An entity owning transmission facilities or having firm contractual rights to use transmission facilities.

3.102 **Transmission Revenue Balancing Account Adjustment (“TRBAA”).** A mechanism established by the Participating TO which will ensure that all Transmission Revenue Credits and other credits specified in Sections 6 and 8 of Appendix F, Schedule 3 of the ISO Tariff, flow through to transmission customers.

3.103 **Transmission Revenue Credit.** The net of: 1) the revenues received by the Participating TO from the ISO for Wheeling service, Usage Charges (excluding any Usage Charges received by the Participating TO as an FTR Holder) and from the sale of an FTR; 2) Existing Transmission Contract (“ETC”) Cost Differentials which include the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO’s rules and protocols; and 3) ISO Charge Type 575 identified as Settlements, Metering, and Client Relations charge.

3.104 **Transmission Revenue Requirement (“TRR”).** The TRR is the total annual authorized revenue requirement associated with transmission facilities and...
3.104 Transmission Revenue Requirement ("TRR"). (continued)

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 includes the costs of transmission facilities and Entitlements and deducts Transmission Revenue Credits and credits for Standby Transmission Revenue and the transmission revenue expected to be actually received by the Participating TO for Existing Rights and Converted Rights. The TRR is shown in Appendix I.

3.105 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 (as the case may be) which could not be avoided through the exercise of Good Utility Practice.
3.106 **Usage Charge.** The amount of money, per 1kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific congested Inter-Zonal Interface during a given hour.

3.107 **Utility Distribution Company (“UDC”).** An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.

3.108 **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.

3.109 **Western System Coordinating Council (“WSCC”).** The Western Systems Coordinating Council or its successor.
3.110 **Wheeling Access Charge.** The charge assessed by the ISO that is paid by a Scheduling Coordinator for Wheeling in accordance with Section 7.1 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 may consist of a High Voltage Wheeling Access Charge and a Low Voltage Wheeling Access Charge.

3.111 **Wheeling Out.** Except for Existing Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4. 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.

3.112 **Wheeling Through.** Except for Existing Rights and Non-Converted Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4 of the ISO Tariff, the use of the ISO Controlled Grid for the transmission
3.112 **Wheeling Through.** (continued)

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.

3.113 **Wheeling.** Wheeling Out or Wheeling Through.

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

3.115 **Zone.** A portion of the ISO Controlled Grid within which Congestion is expected to be small in magnitude or to occur infrequently. “Zonal” shall be construed accordingly.
4. **Eligibility.** Transmission service over a Participating TO’s system shall be provided only to Eligible Customers. Any dispute as to whether a 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, Low Voltage Access Charge equal to the product of the Participating TO’s Low Voltage Access Charge rate and the Low Voltage Access Charge customer’s Gross Load, as provided by the ISO. The Participating TO’s monthly charges to be applied to Low Voltage Access Charge customers are determined pursuant to the provisions of Appendices VIII and IX hereof. The Low Voltage Access Charge applicable for the current Rate Effective Period is shown on SDG&E’s OASIS, which can be accessed at www.sdge.com\toforum, or through a link to SDG&E’s web page that is located on the CAISO website at www.caiso.com.

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 TO’s Low Voltage Wheeling Access Charge is determined pursuant to the provisions of Appendices VIII and IX hereof. The Low Voltage Wheeling Access Charge applicable for the current Rate Effective Period is available on SDG&E’s OASIS, which is shown at www.sdge.com\toforum, or through a link to SDG&E’s web page that is accessible through the CAISO’s OASIS at www.caiso.com.
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 rate and TACBA rate. For a Local Publicly Owned Electric Utility that is a Participating TO, such rates shall be submitted to the ISO for information only. In addition, all customers of a Local Publicly Owned Electric Utility that is a Participating TO shall be subject to the Local Regulatory Authority authorized TRBAA, which shall also be submitted to the ISO. The Participating TO’s End-User transmission rates, by retail rate schedule, are determined pursuant to the provisions of Appendices VIII and IX hereof. The End-User transmission rates applicable during the Rate Effective Period are available on SDG&E’s OASIS, which is shown at [www.sdge.com\toforum](http://www.sdge.com\toforum), or through a link to SDG&E’s web page that is accessible through the CAISO’s OASIS at [www.caiso.com](http://www.caiso.com). 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 shall be used to develop the Access Charges set forth in 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 Adjustment (“TRBAA”) that will ensure that all Transmission Revenue Credits and the refunds, specified in Sections 6 and 8 of Appendix F. Schedule 3 of the ISO Tariff, associated with transmission service are flowed through to customers taking transmission service from the ISO. The TRBAA shall be equal to:

\[
TRBAA = Cr + Cf + I + U
\]

Where:

\[
Cr = \text{The principal balance in the TRBAA recorded in FERC Account No. 254 as of September 30 of the year prior to commencement of the January billing cycle. This balance represents the unamortized}
\]
5.5 **Transmission Revenue Balancing Account Adjustment (TRBAA).** (continued)

balance in the TRBAA from the previous period and the difference in the amount of revenues from Transmission Revenue Credits and the amount of such revenues that has been refunded to customers through operation of the TRBAA, adjusted for franchise fees and uncollectible accounts expense;

\[ \text{Cf} = \text{The forecast of Transmission Revenue Credits for the following calendar year;} \]

\[ \text{I} = \text{The interest balance for the TRBAA, which shall be calculated using the interest rate pursuant to Section 35.19(a) of FERC's regulations under the Federal Power Act (18 CFR Section 35.19(a)). Interest shall be calculated based on the average TRBAA principal balance each month, compounded quarterly; and} \]

\[ \text{U} = \text{An adjustment uncollectible accounts expense if applicable.} \]

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:

\[ \text{TRBAA Rate} = \frac{\text{TRBAA}}{S} \]
5.5 **Transmission Revenue Balancing Account Adjustment (TRBAA)** (continued)

Where:

\[ S = \text{The total kilowatt-hours of Gross Load measured at the customer-meter level as recorded for the twelve month period ending September 30 of the year prior to commencement of the January billing cycle.} \]

5.5.1 **ETC Cost Differentials Sub-Account**

5.5.1.1 Retail TRBAA - Beginning on June 1, 2006 and continuing until June 1, 2008, the TRBAA Rate applicable to End-Use Customers shall be increased by $0.00066 per kilowatt-hour to recover over a two year period ETC Cost Differentials. The ETC Cost Differentials are a component of Transmission Revenue Credits, which were incurred by SDG&E as a Participating TO from November 1, 2002 through September 30, 2005 plus the related interest accrued from the date the expenses were incurred beginning in November 2002 through the end of May 2006. Included in these costs is an amount equal to $436,793, excluding interest, which represents in part the ETC Cost Differentials previously refunded by SDG&E to ISO.
wholesale customers pursuant to SDG&E’s refund report, filed on June 3, 2003, in Docket ER97-2364-006, et al, in compliance with Opinions 458 and 458A. The sub-account used to track the amortization of the ETC Cost Differential sub-account shall accrue interest based on 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 sub-account balance each month, compounded quarterly. On June 1, 2008, the surcharge terminates and shall be removed as an adder to the regular retail TRBAA rate, and any amount overcollected/undercollected that is remaining in the ETC Cost Differential sub-account will be eliminated by transferring the balance to the regular TRBA to be recovered or refunded in the following period.

5.5.1.2 ISO Wholesale TRBAA - For purposes of the calculation of SDG&E’s High Voltage Access Charge and High Voltage Wheeling Access Charge, applicable to ISO wholesale customers beginning on June 10, 2006 and continuing thereafter until May 31, 2008, the wholesale TRBAA shall be adjusted by an increase of $13,217,503 per year to reflect
the annual amortization of the wholesale ETC Cost Differentials. These ETC Cost Differentials were incurred by the SDG&E from November 1, 2002 through September 30, 2005 and the related interest expense accrued through May 31, 2006, according to FERC methodology under the Federal Power Act (18 CFR Section 35.19(a)). Included in these costs is an amount equal to $189,373, excluding interest, which represents ETC Cost Differentials previously refunded by SDG&E to ISO wholesale customers pursuant to SDG&E’s refund report filed on June 3, 2003 in Docket ER97-2364-006, et. al, in compliance with Opinions 458 and 458A. The total cash payments made to PTOs and scheduling coordinators in the June 3, 2003 FERC refund report was $626,166, and is the sum of the aforementioned $436,793 in Section 5.5.1.1 and the $189,373 indicated in above.
5.5.1.2.1 For purposes of any SDG&E’s TRBAA filings commencing with service June 10, 2006 through May 31, 2008, the $13,217,503 shall be allocated to SDG&E’s Existing High Voltage, New High Voltage and Low High Voltage facilities pursuant to SDG&E’s most recent Commission approved gross plant allocator as outlined in the ISO Tariff requirements in Appendix F, Schedule 3, Section 12.

5.6 **Transmission Access Charge Balancing Account Adjustment (TACBAA).**

Commencing on the transition date determined under Section 4 of Schedule 3 to Appendix F of the ISO Tariff, the Participating TO shall maintain a Transmission Access Charge Balancing Account Adjustment (TACBAA). Each month the Participating TO shall make two entries to the TACBAA. One entry will equal the difference between (i) the actual charges by the ISO to the Participating TO pursuant to Section 7.1.2 of the ISO Tariff for the High Voltage Access Charge and Transition Charge and (ii) the revenues
7. **Billing and Payment.**

7.1 **End-Users.** Billing and payment rules applicable to End-Users and certain Wholesale Customers serving load in San Diego Gas & Electric Company’s Service area 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.** Within a reasonable time after the Participating TO receives from the ISO the monthly kilowatt-hours to 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 Charge billing. 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’s 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 Dependent Participating TO to cure such failure, a default by the Dependent Participating TO 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...
7.2.3 Default. (continued)

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 UDC, MSS, or Scheduling Coordinator of its intention to suspend service in sixty days, in accordance with FERC policy.

7.3 Wheeling and Usage Charge Revenues. The ISO, pursuant to the ISO Tariff, shall pay to Participating TOs all Wheeling and Usage Charge revenues, excluding Usage Charge revenues payable to FTR Holders.
8. **Obligation to Interconnect or Construct Transmission Expansions & Facility Upgrades.**

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 generation or load of such third party, or modify an existing 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.

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, 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
8.1.1 **Interconnection to Transmission System.** (continued)

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 that Participating TO determines that the Interconnection of a New Facility will have an adverse effect on Encumbrances, the New Facility Operator shall mitigate such adverse effect.

8.1.2 **Costs Associated with Interconnection.** Each party requesting Interconnection shall pay the costs of planning, installing, operating, and maintaining 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. A New Facility Operator shall be responsible for the costs of Reliability Upgrades only if the necessary facilities
8.1.2 Costs Associated with Interconnection. (continued)

are not included in the ISO Controlled Grid Transmission Expansion Plan approved as the New Facility Operator’s Completed Application Date, or the date for the installation of a facility is advanced by the interconnection of the New Facility, in which case the New Facility Operator shall be responsible only for the incremental costs associated with the earlier installation of the facility. Each New Facility Operator may, at its own discretion, sponsor, pursuant to Section 3.2 of the ISO Tariff and Section 9 of this TO Tariff, any Delivery Upgrades. 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. The Participating TO shall tender to the party requesting Interconnection an Interconnection Agreement that will be filed with FERC, or the Local Regulatory Authority, in the case of a Local Publicly
8.1.3 **Interconnection Agreement.** (continued)

Owned Electric Utility. The Interconnection Agreement will include, without limitation, cost, responsibilities and payment provisions for any engineering, equipment, construction, operation and maintenance costs for any Direct Assignment Facilities and any Reliability Upgrades, and Delivery Upgrades, if applicable, 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) Calendar 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...
8.1.3 **Interconnection Agreement.** (continued)

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 applicant not covered by any System Impact Study Agreement or Facilities Study Agreement.

8.1.3.1 **Queuing Provisions.** To maintain its queue position, the New Facility Operator must timely comply with the interconnection requirements of Section 5.7 of the ISO Tariff and Sections 8.1 and 10 of this TO Tariff. If the New Facility Operator fails to timely comply with such interconnection
8.1.3.1 **Queuing Provisions.** (continued)

requirements, such New Facility Operator shall pay the reasonable costs of revising the System Impact Studies for other New Facility Operator’s that have established a new queue position due to the New Facility Operator either withdrawing its Interconnection Application or because its queue position has been modified pursuant to the queuing provisions in Section 5.7.4.4 of the ISO Tariff.

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 and, as applicable, Section 5.7 of the ISO Tariff.

8.1.5 **Energization.** The Participating TO shall not be obligated to energize, nor shall the New Facility Operator or 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 New Facility Operator or
8.1.5 **Energization.** (continued)

wholesale load has demonstrated to the ISO’s reasonable satisfaction that it has complied with all of the requirements of Section 5.7 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 **Participating TO Obligation to Construct Transmission 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 of Section 3.2, the ISO Tariff, and this TO Tariff.
8.2.1 **Obligation to Construct.** A Participating TO shall not be obligated to construct or expand Interconnection facilities, 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 Interconnection facilities, 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 coordination 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 3.2 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 Project 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 the 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
9.2.1 **Due Diligence to Construct.** (continued)

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
9.2.2 **Delay in Construction or Expansion.** (continued)
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 **Provisions Relating to 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
9.3.1 **Responsibility for Third Party Additions.** (continued)

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.
9.3.2 **Coordination of Third-Party System Additions.** (continued)

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 TO’s”.** Notwithstanding any other provision of this TO Tariff, prior to requesting that a Local Furnishing Participating TO construct or expand facilities, or utilize existing facilities, the ISO or Project Sponsor, if necessary as determined by the Local Furnishing Participating TO, 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 Interconnection or 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 213(b).
9.3.3  **Expansion by “Local Furnishing Participating TO’s”**: (continued)

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, or permit the utilization of existing 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 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.

10.2 **Applications.** Except as provided in Section 10.2.1, a party requesting Interconnection shall submit written Interconnection Applications 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.

10.2.1 **New Facility Operator.** If the party requesting Interconnection to the ISO Controlled Grid is a New Facility Operator, such party shall submit a written Interconnection Application to the ISO pursuant to Section 5.7.3 of the ISO Tariff that shall include the information required in Section 10.3 of this TO Tariff.
10.3 **Completed Interconnection Application.** A Completed 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 energizing the Interconnection and the term of the Interconnection service

(v) If the applicant is a New Facility Operator, completed generator data sheets pursuant to the requirements of the Participating TO.

(vi) 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.

(vii) If the applicant is a wholesale load, the electrical of the source of the power (if known) to be transmitted pursuant to the applicant’s request
10.3 **Completed Interconnection Application.** (continued)

for Interconnection. If the source of the power is not known, a system sale will be assumed; and

(viii) The electrical location of the ultimate load (if known). If the location of the load is not known, a system sale will be assumed.

In addition, if the applicant proposes to perform or cause a third party to perform any required System Impact Study or any required Facilities Study, it shall so indicate in its Interconnection Application. The results of any study or studies performed by a New Facility Operator must be approved by both the ISO and the Participating TO. Within 10 Business Days after receipt of an Interconnection Application, the Participating TO, and the ISO, if applicable, 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 or to the ISO if the applicant is a New Facility Operator. The Participating TO will treat the information provided in the Interconnection
10.3 **Completed Interconnection Application.** (continued)

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.

10.3.1 **Amendment to Completed Interconnection Application.** An applicant shall only be limited to amending its Completed Interconnection Application once. Such amendment shall occur on or before ten (10) Business Days following the date the Participating TO tenders any Facilities Study Agreement. Specifically, as an alternative to executing and returning Facilities Study Agreement, a New Facility Operator may submit an amendment to its Completed Interconnection Application to reflect a revised configuration for its New Facility. The amended Completed Interconnection
10.3.1 Amendment to Completed Interconnection Application. (continued)

Application shall be treated in accordance with Section 5.7.4.2.1 of the ISO Tariff and Section 10.7 of this TO Tariff, the New Facility Operator's Completed Interconnection Application shall not be deemed withdrawn; and the New Facility Operator shall maintain its existing queue position, if (a) the amended Completed Interconnection Application is received by the Participating TO within ten (10) Business Days of the Participating TO's tender of a Facilities Study Agreement; and (b) the New Facility Operator has not submitted a previous amendment to the Completed Interconnection Application. In the event a New Facility Operator amends its Completed Interconnection Application, it will be responsible for any additional study costs that result from that amendment, including costs associated with revisions to studies for other applicants holding later queue positions.

10.4 Review of Completed Interconnection Agreement. After receiving a Completed Interconnection Application, the Participating TO, and the ISO, if applicable, will determine on a non-discriminatory basis whether a System
10.4 **Review of Completed Interconnection Agreement.** (continued)

Impact Study is required. Whenever the Participating TO, and the ISO, if applicable, 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, 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 twenty (20) 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, and the ISO, if applicable, 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 or reviewing 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. Alternatively, if the New Facility Operator will perform the System Impact Study, 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
10.5 **Notice of Need for System Impact Study.** (continued)

reviewed 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 reviewing the required System Impact
Study. 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 the System
Impact Study or reviewing the New Facility Operator’s System Impact Study.
Alternatively, if the applicant requests the Participating TO to proceed with the
System Impact Study or review thereof 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
10.5 **Notice of Need for System Impact Study.** (continued)

a System Impact Study Agreement, and does not request that the Participating TO proceed with the System Impact Study or review thereof, 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 either (a) complete the required System Impact Study within a sixty (60) day period or (b) complete its review of a New Facility Operator’s System Impact Study within thirty (30) Calendar Days of its receipt of the completed study. The System Impact Study will identify whether any Direct Assignment Facilities or Reliability Upgrades as well as, if applicable, any Delivery Upgrades are necessary to deliver a New Facility’s full output over the ISO Controlled Grid. The System Impact Study will also identify any adverse impact on Encumbrances existing as of the applicant’s New Facility Operator’s Completed Application Date. In the event that the Participating TO is unable to complete the required System Impact Study within such time...
10.7 **System Impact Study Procedures.** (continued)

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. 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 or review and approval of a New Facility Operator’s 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 performed...
10.7.1 Procedures Upon Completion of System Impact Study. (continued)

by the Participating TO or receipt of written approval of the New Facility Operator’s System Impact Study from the Participating TO and the ISO, the applicant shall request the Participating TO to tender an Interconnection Agreement. Within twenty (20) 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, or the completion of review and approval of the New Facility Operator’s System Impact Study by the Participating TO and the ISO, tender to the applicant a Facilities Study Agreement that defines the scope, content, assumptions and terms of reference for such study to be completed by the
10.8 **Notice of Need for Facilities Study.** (continued)

Participating TO; 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. Alternatively, if the New Facility Operator will perform the Facilities Study, the Participating TO shall within fifteen (15) Business Days of the completion date of the System Impact Study or the completion of review and approval of the New Facility Operator’s System Impact Study, tender a Facilities Study Agreement that defines the scope, content, assumptions and term of reference for such study to be reviewed by the Participating TO; the estimated time required to complete the required review; 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 cost of reviewing 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 costs.
10.8 **Notice of Need for Facilities Study.** (continued)

estimated cost of the Facilities Study or reviewing the New Facility Operator’s Facilities Study. Alternatively, if the applicant requests the Participating TO to proceed with the Facilities Study or review thereof 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 Procedure.** 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 either (a) complete the required Facilities Study within a sixty (60) Calendar day period or (b) complete its review of a New Facility Operator’s Facilities Study within thirty (30) Calendar Days of its receipt of the completed study. 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 performed by the Participating TO or receipt of written approval of the New Facility Operator’s Facilities Study from the Participating TO, the applicant shall request the Participating TO to tender an Interconnection Agreement. Within twenty (20) Business Days of
10.9.1 **Execution of Interconnection Agreement.** (continued)

such request, the Participating TO shall tender to 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 to the transmission system 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
10.11 **Expedited Interconnection Procedures.** (continued)

applicant shall submit in writing a Request for Expedited Interconnection

Procedures to the Participating TO, and to the ISO, if the applicant is a New

Facility Operator, 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
10.11 **Expedited Interconnection Procedures.** (continued)

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.
11.1 Procedures to Follow if Uncontrollable Force Occurs. (Continued)

under this TO Tariff if prevented from fulfilling the obligation due to the
occurrence of an Uncontrollable Force.

11.2 Indemnification. A Market Participant shall at all times indemnify, defend,
and save the Participating TO harmless from any and all damages, losses,
calls, (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.,
12.2 **Stranded Cost Recovery.** (continued)

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 the Participating TO’s Low Voltage Transmission Facilities.** For the purpose of determining the ability of a UDC, MSS, and Scheduling Coordinator to meet its obligations related to service using the Participating TO’s Low Voltage Transmission Facilities hereunder, 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 and Certain Wholesale Customers.** Creditworthiness rules applicable to End-Users and certain Wholesale Customers serving load in San Diego Gas & Electric Company’s Service Area 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 the FPA.
15. **Recovery of Reliability Service Costs.** Reliability Service costs payable by a utility that is a Participating TO pursuant to the ISO Tariff shall be recovered from End-Users located in the Service Area of that utility and certain Wholesale Customers serving load in San Diego Gas & Electric Company’s Service Area. Such utility shall file with the Commission and/or the appropriate Local Regulatory Authority(ies) a mechanism for such cost recovery. The recovery of Reliability Service charges applicable to such End Users and certain Wholesale Customers serving load in San Diego Gas & Electric Company’s Service Area, is set forth in Appendices V, VI, and VII attached hereto.
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 IV. Any Party may at any time, by notice to the other Parties, change the designation or address of the person specified in Appendix IV 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
16.2 **Waiver.** (continued)

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
16.6 **Severability.** (continued)

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 Revenue Requirement

1. End-Use Customers: For the purpose of the calculation of the End-User Access Charge for transmission services, the Transmission Revenue Requirement is equal to the retail Base Transmission Revenue Requirement determined pursuant to the formula stated in Appendix VIII reduced by the TRBAA associated with End-Use Customers.

2. For purposes of the ISO’s calculation of Access Charges:
   a. The High Voltage Transmission Revenue Requirement is comprised of the Base Transmission Revenue Requirement associated with High Voltage Transmission Facilities determined pursuant to the formula stated in Appendix VIII hereof, the TRBAA associated with High Voltage Transmission Facilities, and Stand-by Transmission Revenues determined pursuant to Appendices VIII and IX hereof.
   b. The Low Voltage Transmission Revenue Requirement is comprised of the Base Transmission Revenue Requirement associated with Low Voltage Transmission Facilities determined pursuant to the formula stated in Appendix VIII hereof, the TRBAA associated with Low Voltage Transmission Facilities, and Stand-by Transmission Revenues determined pursuant to Appendices VIII and IX hereof.
   c. Gross Load consistent with the High Voltage Transmission Revenue Requirement shall be 19,404,874-megawatt hours.

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Vice President, Regulatory Affairs

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Docket: ER03-601-002
Effective: Oct 1, 2003

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER03-601-000, issued December 18, 2003.
# APPENDIX II

## Charges For Wholesale Transmission Services

<table>
<thead>
<tr>
<th>Service</th>
<th>Determination</th>
</tr>
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<tbody>
<tr>
<td>High Voltage Wheeling Access Charge</td>
<td>See ISO Tariff</td>
</tr>
<tr>
<td>Low Voltage Wheeling Access Charge</td>
<td>Determined in accordance with Appendices VIII and IX</td>
</tr>
<tr>
<td>Low Voltage Access Charge</td>
<td>Determined in accordance with Appendices VIII and IX</td>
</tr>
<tr>
<td>High Voltage Utility-Specific Rate</td>
<td>Determined in accordance with Appendices VIII and IX</td>
</tr>
</tbody>
</table>

(1) High Voltage Utility Specific Rate reflects Transmission Surcharge rate per Docket ER01-3074-000 and Security Revenues in Docket ER02-1687-000.
APPENDIX III

Access Charges for End-Use Customers

[SEE ATTACHED]
RESERVED SHEET
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Vice President, Regulatory Affairs

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Docket: ER03-601-002

Effective: Oct 1, 2003

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER03-601-000, issued December 18, 2003
RESERVED SHEET
RESERVED SHEET
RESERVED SHEET
Retail
Transmission Revenue Balancing Account Adjustment Rate

(TRBAA)

A Transmission Revenue Balancing Account Adjustment Rate equal to ($0.00058) per kilowatt-hour shall be applied to all SDG&E End-User Customers bills.
ISO Wholesale
Transmission Revenue Balancing Account Adjustment
TRBAA
Service Year 2007

A: Pre-January 1, 2001 Facilities:
   High Voltage TRBAA $ (15,702,833)
   Low Voltage TRBAA 2,567,307
   Sub-Total $ (13,135,526)

B: Post-January 1, 2001 Facilities:
   High Voltage TRBAA  286,507
   Low Voltage TRBAA   1,419,654
   Sub-Total $  1,706,161

C: Total ISO Wholesale TRBAA:
   $ (11,429,365)
Transmission Access Charge Balancing Account Adjustment Rate

(TACBAA)

A Transmission Access Charge Balancing Account Adjustment Rate equal to ($0.00036) per kilowatt-hour shall be billed to all SDG&E End-User Customers.
APPENDIX IV

Notices

Designated Representative:

David B. Follett
Associate General Counsel
101 Ash Street
Post Office Box 1831
San Diego, CA    92101
Telephone:  (619) 699-5053
Facsimile:   (619) 699-5074
APPENDIX V

Reliability Services Revenue Requirement

1. The Reliability Services Revenue Requirement of $118,047,000 is equal to the forecast of Reliability Services payments the Participating TO will make to the ISO during the twelve month period following the Effective Date of the Rate Schedule, the balance in the RS balancing account from the preceding year, including an adjustment for franchise fees and uncollectible accounts expense.

2. The amount in (1) shall be effective until amended by the Participating TO in accordance with Appendix VI to this Tariff.
APPENDIX VI

Reliability Services Rate Schedule

1. **Applicability.** This rate schedule is applicable to all End-Users of SDG&E and Wholesale Customers serving load in SDG&E’s Service Area.

2. **Description.** The purpose of this Reliability Services Rate Schedule is to set forth rates to be charged by the Participating TO for the recovery of Reliability Services costs billed to the Participating TO by the ISO or costs directly incurred by SDG&E that enhance reliable grid operations and local area reliability. RS costs incurred by the ISO are recovered from the utility that is a party to a Transmission Control Agreement in whose Service Area the RMR Generating Unit is located. Additionally, RS costs shall include costs incurred by SDG&E in implementing the procurement procedures commencing on June 21, 2005, in compliance with CPUC Decision 04-07-028 (July 8, 2004) in order to enhance reliable grid operations and local area reliability (the “Procurement Procedures”). The Procurement Procedures, which were set forth in SDG&E Advice Letter 1641-E (approved by the CPUC on February 10, 2005), are described in Section 3 of this Appendix VI. Pursuant to Section 15 of the Transmission Owners Tariff, the Participating TO is to recover the RS costs it is assessed by the ISO from End-Users located in the Participating TO’s Service Area and Wholesale Customers serving load in San Diego Gas & Electric Company’s Service Area. The term "Service Area" shall be as defined in the ISO Tariff.
3. **Provision of Reliability Services by SDG&E.** Under Decision 04-07-028, SDG&E is responsible for scheduling and procuring sufficient and appropriate resources to meet its customers’ needs and to permit the ISO to maintain reliable grid operations.

In compliance with Decision 04-07-028, and in conformity with the Procurement Procedure, SDG&E undertakes the following actions:

1) SDG&E estimates the ISO’s intra-zonal congestion mitigation costs (expressed in $/MWh) on each potential path for delivering energy based on the most recent publicly available data contained in reports prepared by the ISO’s Department of Market Analysis. This data allows SDG&E to estimate the ISO’s intra-zonal congestion mitigation costs when energy is delivered over one of those paths.

2) For each contemplated procurement and scheduling transaction, SDG&E applies “effectiveness factors” provided by the ISO to inform SDG&E how effective any procurement and scheduling activity might be towards mitigating or exacerbating congestion on any potentially constrained intra-zonal transmission path. SDG&E applies these forecast mitigation costs and the “effectiveness factors” to calculate a “cost adder” that accounts for the incremental impact of any transaction at a designated path on Intra-Zonal Congestion, as defined in the ISO Tariff. SDG&E then makes its procurement decisions based on market prices plus the “cost adder” to assure local reliability at the minimum overall costs, taking potential congestion costs into account. The difference between the actual cost of energy...
3. **Provision of Reliability Services by SDG&E.** (continued)

procured under this procedure and the cost that SDG&E would have incurred by procuring energy from other sources absent this procedure will be entered into SDG&E’s RS balancing account as described in Section 4 of this Appendix VI.

4. **Reliability Service Revenue Requirement.**

The initial RS revenue requirement, that 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 RS revenue requirement shall be equal to the forecast RS payments the Participating TO will make to the ISO during the twelve-month period following the Effective Date.

Subsequent to the establishment of the initial RS revenue requirement, the revenue requirement and associated RS charges shall be revised annually 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 RS revenue requirement and RMR charges in December of the year prior to January 1 of the following calendar year, requesting as necessary, waiver of all prior notice requirements. In the annual revision, the RS revenue requirement shall be established based on the forecast of RS costs for the calendar year, plus the recorded balance in the RS balancing account (RSBA) as of November 30 of the year prior to commencement of the following calendar year.
4. **Reliability Services Revenue Requirement.** (continued)

The RSBA is a mechanism that is designed to ensure that SDG&E neither under recovers nor over recovers from customers the RS costs. The balance in the account represents the cumulative difference between the revenues billed by SDG&E under RS charges to End User Customers and Wholesale Customers serving load in SDG&E’s Service Area and the RS costs paid by SDG&E to the ISO, plus costs incurred by SDG&E pursuant to Section 3 of this Appendix VI, 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.

5. **RS Charges.** Charges for recovery of the RS Requirement are provided in Appendix VII.

6. **Effective Date.** This rate schedule is effective for service rendered on and after the date designated by the Commission.
APPENDIX VII

Reliability Must-Run Charges for End Users

[SEE ATTACHED]

1 These charges represent the rates for recovery of the RMR revenue requirement.

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Vice President, Regulatory Affairs  128C14
Issued on: Jan 13, 2004  Effective: Oct 1, 2003
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER03-601-000, issued December 18, 2003
## Summary of Reliability Services Retail Transmission Rates
### 2006 Service Year

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<th>Line No.</th>
<th>Customer Classes</th>
<th>(A) Transmission Level Energy Rates $/kWh</th>
<th>(B) Transmission Level Demand Rates $/kW-Mo</th>
<th>(C) Primary Level Demand Rates $/kW-Mo</th>
<th>(D) Secondary Level Demand Rates $/kW-Mo</th>
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<td>3</td>
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<td>Medium &amp; Large Commercial/Industrial (1)</td>
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(1) Demand rate applied to customers’ monthly maximum demand.
(2) Demand rate applied to standby customers’ contract demand.

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Senior Vice President, Regulatory Affairs

Issued on: Dec 20, 2006  
Effective: Jan 1, 2007
RESERVED SHEET
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RESERVED SHEET
RESERVED SHEET
Wholesale RS Rate

$/kWh

Wholesale RS rate $0.00585
APPENDIX VIII

FORMULA FOR CALCULATING ANNUAL BASE TRANSMISSION REVENUE REQUIREMENTS UNDER SDG&E’S TRANSMISSION OWNER TARIFF

This Appendix VIII sets forth the formula for calculating the annual Base Transmission Revenue Requirement ("BTRR") and is organized into the following sections:

Introduction

I. Definitions
   A. Allocation Factors
   B. Terms
      1. Accumulated Deferred Income Taxes
      2. Administrative and General Expense
      3. Amortization of Investment Tax Credits
      4. Amortization of Unamortized Loss on Reacquired Debt
      5. Annual Fixed Charge Rate
      6. Base Period
      7. Common Plant
      8. Common Plant Depreciation Expense
      9. Common Plant Depreciation Reserve
      10. CPUC Intervenor Funding Expense
      11. Depreciation Expense for Transmission Plant
      12. Electric Miscellaneous Intangible Plant
      13. Electric Miscellaneous Intangible Plant Amortization Expense
      14. Electric Miscellaneous Intangible Plant Amortization Reserve
      15. Forecast Period
      16. General Plant
      17. General Plant Depreciation Expense
      18. General Plant Depreciation Reserve
      19. Materials and Supplies
      20. Municipal Franchise Tax Expense
      21. Other Regulatory Assets/Liabilities
      22. Payroll Taxes
23. Prepayments
24. Property Insurance
25. Property Taxes
26. Return and Associated Income Taxes
27. South Georgia Income Tax Adjustment
28. Total Plant in Service
29. Transmission Depreciation Reserve
30. Transmission, General, and Common Plant Depreciation Expense
31. Transmission Operation and Maintenance Expense
32. Transmission Plant
33. Transmission Plant Held for Future Use
34. Transmission Related A&G Expenses
35. Transmission Related Amortization of Excess Deferred Tax Liabilities
36. Transmission Related Amortization of Investment Tax Credits
37. Transmission Related Cancelled Project Cost
38. Transmission Related Cancelled Project Cost Amortization Expense
39. Transmission Related Miscellaneous Intangible Plant Amortization Expense
40. Transmission Related Municipal Franchise Tax Expense
41. Transmission Related Payroll Taxes Expense
42. Transmission Related Property Taxes
43. Transmission Related Regulatory Debits
44. Transmission Related Revenue Credits
45. Transmission Related Uncollectible Expense
46. True-Up Period
47. Uncollectible Expense
48. Valley Rainbow Project Costs
49. Weighted Forecast Plant Additions

II. Calculation of Annual Transmission Revenue Requirement
   A. Return and Associated Income Taxes
   B. End Use Customer Base Transmission Revenue Requirement
   C. ISO Base Transmission Revenue Requirement
   D. True-Up Adjustment Calculation
INTRODUCTION

This Appendix sets forth details with respect to the determination each year of San Diego Gas & Electric Company’s (“SDG&E”) Base Transmission Revenue Requirements used to derive the charges assessed by SDG&E to its End Use Customers (“BTRREU”) and SDG&E’s Base Transmission Revenue Requirements used to derive the transmission charges assessed by SDG&E pursuant to its Transmission Owner (“TO”) Tariff and by the California Independent System Operator Corporation (“ISO”) pursuant to the ISO Tariff (“BTRRISO”). The BTRREU and BTRRISO for each Rate Effective Period will each be comprised of the following three parts:

(i) the Prior Year Revenue Requirements (“PYRR”);
(ii) the Forecast Period Capital Addition Revenue Requirements (“FC”); and
(iii) a True-Up Adjustment

The PYRR, FC and True-Up Adjustment shall be designed to reflect SDG&E’s cost to own, operate and maintain its transmission facilities.

The PYRR will be an annual calculation based on the previous calendar year’s data as shown in SDG&E’s FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees, and Others (“Form 1”) for that year and underlying ledger accounts. SDG&E shall make available the data reflected in the underlying ledger accounts used to determine SDG&E’s PYRR in the annual informational filing described below. Valley Rainbow Project Costs (as defined below) shall be recovered commencing October 1, 2003 in accordance with this Appendix VIII as a component of PYRR as defined in

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Docket: ER07-284-000

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Effective: July 1, 2007

Sections II.B and C hereof. The extent to which Transmission Related Cancelled Project Cost (as defined below) will be included in SDG&E’s formula rate will be determined on a case-by-case basis pursuant to FERC authorization. CPUC Intervenor Funding Costs (as defined below) will be recovered as a component of PYRR for End Use Customers, but not for ISO customers. The FC component will be an annual calculation based on an estimate of the revenue requirements associated with the transmission-related plant investments expected to be placed in service during the Forecast Period. The True-Up Adjustment for each Rate Effective Period will be an annual reconciliation of the difference between

(a) SDG&E’s actual cost of providing transmission service during the most recent consecutive twelve-month period (the “True-Up Period”) ending March 31 preceding that Rate Effective Period as determined by application of the PYRR component of the formula rate; and

(b) actual revenues billed by SDG&E and paid by transmission customers for transmission service during the True-Up Period.

SDG&E shall submit to the Commission on or before August 15 of each year an informational filing (the “Informational Filing”) showing the rates in effect for the Rate Effective Period beginning September 1 of that year through August 31 of the subsequent year. Further, the Informational Filing shall show:

1. for the PYRR or Base Period, the average of the thirteen monthly balances for transmission-related plant investment and
the transmission-related plant retirements, reclassifications or
additions causing such change; and

1. for the Forecast Period, any forecast additions to transmission-
related plant net of forecast retirements and reclassifications of
Transmission Plant anticipated during that Forecast Period.

On or before June 15, SDG&E shall provide to the California Public Utilities
Commission ("CPUC"), and make available to any other interested parties, by posting
on its OASIS at www.sdge.com\toforum, a draft (the "Draft Informational Filing") of the
Informational Filing (not including individual project forecast plant additions), for review,
comment and discussion prior to the submission of the Informational Filing. Information
on individual project forecast plant additions will be provided to the CPUC and to parties
other than the CPUC requesting this information, subject to the execution by such party
of a non-disclosure agreement, should SDG&E reasonably determine that such
information should be treated as confidential to protect transmission system security or
to prevent competitive cost information from being made publicly available. The Draft
Informational Filing will also be available through a link to SDG&E’s web page that is

The Informational Filing shall not subject the formula set forth in this Appendix
VIII to modification, but rather is contestable only with respect to prudence of the costs
and expenditures included for recovery, as well as the accuracy of data and the
consistency with the formula of the charges shown in the Informational Filing.
Any revisions to the information reflected in the Draft Informational Filing after it has been made available to the public but prior to submission of the Informational Filing to the Commission will be reflected in the Informational Filing, which will be filed no later than August 15. Any revisions and refunds related to End Use Customer Base Transmission Revenue Requirements ("BTRR_{EU}\) resulting from a Commission Order will be reflected as provided by such a Commission Order in subsequent billings.

Revisions to ISO Base Transmission Revenue Requirements ("BTRR_{ISO}\) resulting from a Commission Order, will be made to billings pursuant to such Commission Order and as prescribed by the ISO Tariff. All changes or corrections to rates that result in refunds will be with interest as calculated pursuant to 18 C.F.R. Section 35.19a.

For Incentive Projects, to the extent SDG&E seeks to recover in rates revenues for incentives permitted by FERC Order No. 679, SDG&E shall make a separate, project-specific filing under Section 205 of the Federal Power Act ("FPA") explicitly requesting the incentive rate treatment being sought and a September 1 effective date, which is concurrent with the beginning of the annual Rate Effective Period for each new rate cycle under this Appendix VIII and to seek additional incentives permitted by FERC Order No. 679, as may be modified from time to time. Project-specific filing(s) under Section 205 of the FPA shall specify how the incentive costs will be recovered under Appendix VIII. Parties may object to the proposed incentive(s) and methodology in the filing(s) under Section 205 of the FPA; provided, however, that parties shall not object on grounds that the TO3 Formula precludes SDG&E from obtaining additional incentives.
In the event of a challenge to any cost reflected in charges derived under this Appendix VIII, SDG&E shall bear the burden of demonstrating that such costs and expenditures included for recovery were prudently incurred, as well as the accuracy and consistency with the formula of the information contained therein.
I. DEFINITIONS

Capitalized terms not otherwise defined in Section 3 of SDG&E’s Transmission Owner Tariff, in this Appendix VIII, in the ISO Tariff, or in this Appendix VIII have the following definitions:

A. ALLOCATION FACTORS

1. **Seven-Element Adjustment Factor** shall be a factor calculated by SDG&E to be applied by SDG&E to the relevant accounts, if necessary, for the purposes of properly functionalizing such accounts between transmission and distribution in accordance with the guidelines set forth in the Commission’s Order No. 888, as those guidelines, as applicable to SDG&E, may be modified by the Commission from time to time. Electric Miscellaneous Intangible Plant will not be taken into account in the derivation of the Seven Element Adjustment Factor.

2. **Transmission Wages and Salaries Allocation Factor** shall equal the ratio of SDG&E’s transmission-related direct wages and salaries to SDG&E’s total direct wages and salaries, excluding administrative and general wages and salaries.

3. **Transmission Plant Allocation Factor** shall equal the ratio of the sum of SDG&E’s total investment in (a) Transmission Plant,
(b) transmission related General Plant and transmission related Common Plant and (c) transmission related Electric Miscellaneous Intangible Plant to SDG&E’s Total Plant in Service.

4. **Transmission Plant Property Insurance Allocation Factor** shall equal the ratio of the sum of SDG&E’s total investment in Transmission Plant and transmission related General Plant and transmission related Common Plant, to SDG&E’s Total Plant in Service, excluding SDG&E’s ownership share in the San Onofre Nuclear Generation Station (“SONGS”).

5. **Existing and New HV and LV Allocation Factors:** For purposes of SDG&E’s BTRRISO, SDG&E will allocate its transmission revenue requirements between Existing High Voltage (“HV”) and Existing Low Voltage (“LV”) Transmission Facilities and between New HV and New LV Transmission Facilities based on the respective percentages and in-service dates of such facilities owned by SDG&E, which are classified as such in accordance with ISO’s guidelines approved in Docket Nos. ER01-831-000 and ER00-2019-006.

6. **Transmission Related Property Tax Allocation Factor** shall equal the ratio of SDG&E’s total Transmission Plant and transmission related General Plant and transmission related Common Plant, to SDG&E’s Total Plant In Service, excluding SONGS.
B. TERMS

1. **Accumulated Deferred Income Taxes** shall equal the net of the deferred tax balance recorded in FERC Account Nos. 281-283 and the deferred tax balance recorded in FERC Account No. 190.

2. **Administrative and General Expense** shall equal SDG&E’s expenses recorded in FERC Account Nos. 920-935, excluding FERC Account No. 930.1 (General Advertising Expense).

3. **Amortization of Investment Tax Credits** shall equal SDG&E’s credits recorded in FERC Account No. 411.4.

4. **Amortization of Unamortized Loss on Reacquired Debt** shall equal SDG&E’s expenses recorded in FERC Account No. 428.1.

5. **Annual Fixed Charge Rate** ("AFCR") shall be the rate shall be the rate multiplied by Weighted Forecast Plant Additions that yields Forecast Period revenue.

6. **Base Period**, except for the initial Base Period, shall be the calendar year for which SDG&E’s most recent FERC Form 1 is available. The initial Base Period shall be the 12-month period ending June 30, 2006.
7. **Common Plant** shall equal SDG&E’s gross plant balance recorded in FERC Account Nos. 303 and 389 through 398 assigned to electric service.

8. **Common Plant Depreciation Expense** shall equal SDG&E’s depreciation expenses related to Common Plant recorded in FERC Account Nos. 403, 404, and 405 in accordance with depreciation rates authorized by the CPUC.

9. **Common Plant Depreciation Reserve** shall equal SDG&E’s depreciation reserve balance related to Common Plant recorded in FERC Account Nos. 108 and 111.

10. **CPUC Intervenor Funding Expense** shall equal those expenses recorded in FERC Account No. 928 incurred by SDG&E associated with its requirement to reimburse intervenors participating in CPUC regulatory proceedings involving transmission projects as ordered and approved by the CPUC. With respect to the amount of CPUC Intervenor Funding Expense associated with the cancelled Valley Rainbow project that shall be recoverable pursuant to this Appendix VIII, such expense shall be limited to no more than $700,000. To the extent such actual expense is less than $700,000, the difference between the actual lower expense and the $700,000 limit...
shall be reconciled as part of the first True-Up Adjustment described in Section II.D of this Appendix VIII.

11. **Depreciation Expense for Transmission Plant** shall equal SDG&E’s transmission expenses recorded in FERC Account Nos. 403, 404, and 405, which are based on asset service lives authorized by FERC. To the extent SDG&E seeks to modify its Transmission Plant depreciation rates, it will do so pursuant to Section 205 of the FPA. To the extent SDG&E is allowed to recover accelerated depreciation for an Incentive Project, the difference between accelerated depreciation and depreciation based on asset service lives for the Incentive Project shall be recorded in FERC Account No. 407.3 Regulatory Debits and the offsetting entry shall be recorded in FERC Account No. 254 Other Regulatory Liabilities.

12. **Electric Miscellaneous Intangible Plant** shall equal SDG&E’s costs recorded in FERC Account No. 303 related to Electric Miscellaneous Intangible Plant.

13. **Electric Miscellaneous Intangible Plant Amortization Expense** shall equal SDG&E’s costs recorded in FERC Account No. 404 related to the amortization of Electric Miscellaneous Intangible Plant.
14. **Electric Miscellaneous Intangible Plant Amortization Reserve** shall equal SDG&E’s costs recorded in FERC Account No. 111 related to the amortization reserve of Electric Miscellaneous Intangible Plant.

15. **Forecast Period** with respect to each Rate Effective Period shall be the period beginning April 1 of the calendar year in which that Rate Effective Period begins, through the end of that Rate Effective Period, except that for the Rate Effective Period ending August 31, 2008, the Forecast Period shall be the period beginning July 1, 2006 and ending June 30, 2008.

16. **General Plant** shall equal SDG&E’s gross plant balance recorded in FERC Account Nos. 389-399.

17. **General Plant Depreciation Expense** shall equal SDG&E’s depreciation expenses related to General Plant recorded in FERC Account Nos. 403, 404, and 405 in accordance with depreciation rates authorized by the CPUC.

18. **General Plant Depreciation Reserve** shall equal SDG&E’s depreciation reserve balance related to General Plant recorded in FERC Account Nos. 108 and 111.
19. **Incentive** refers to any of the following items delineated in FERC Order No. 679, as may be modified from time to time:

   a. Incentive rates of return on equity for new investment;

   b. Full recovery of prudently incurred Pre-Commercial Operations Costs;

   c. Full recovery of prudently incurred costs of abandoned facilities;

   d. Accelerated depreciation;

   e. Deferred cost recovery for utilities with retail rate moratoriums;

   f. 100% recovery of construction work in progress in rate base;

   g. Incentive rates of return on equity for advanced transmission technologies;

   h. An up-to-50 basis point incentive adjustment of return on equity for utilities that join and/or continue to be members of or to participate in transmission organizations, such as (but not limited to) regional transmission organizations and independent system operators; and

   i. Hypothetical capital structure.

20. **Incentive Project** shall be a transmission capital project for which the FERC authorizes the utility under Section 205 of the FPA to
collect in its rates specified Incentive(s) permitted by FERC Order No. 679 as may be modified from time to time.

21. **Incentive Return on Equity** shall be an Incentive return on equity approved for an Incentive Project.

22. **Materials and Supplies** shall equal SDG&E’s balance of total electric Materials and Supplies recorded in FERC Account No. 154, excluding those materials and supplies assigned to construction as reflected on SDG&E Form 1.

23. **Municipal Franchise Tax Expense** shall equal the amounts recorded in FERC Account No. 927.

24. **Non-Incentive** refers to items not delineated as Incentives in FERC Order No. 679 or in subsection 19 above.

25. **Non-Incentive Project** shall be a transmission capital project for which SDG&E does not seek to collect in its rates the specified Incentives provided for in FERC Order No. 679 or in subsection 19 above for projects that are approved as Incentive Projects.

26. **Non-Incentive Return on Equity** shall be 13.0%.

27. **Other Regulatory Assets/Liabilities** shall equal amounts recorded in FERC Account No. 182.3 that the Commission has accepted for
recovery under Section 205 of the FPA. Other Regulatory Assets/Liabilities for the initial Rate Effective Period shall be zero.

28. **Payroll Taxes** shall equal those payroll tax expenses recorded in FERC Account No. 408.1.

29. **Pre-Commercial Operations Costs** for Non-Incentive Projects shall equal costs recorded in FERC Account No. 183. **Pre-Commercial Operations Costs** for Incentive Projects charged to expense pursuant to FERC Order No. 679 shall be recorded in FERC Account No. 566 Miscellaneous Transmission Expenses.

30. **Prepayments** shall equal SDG&E’s prepayment balance recorded in FERC Account No. 165.

31. **Property Insurance** shall equal SDG&E’s expenses recorded in FERC Account No. 924.

32. **Property Taxes** shall equal SDG&E’s expense recorded in FERC Account No. 408.1.

33. **Return and Associated Income Taxes** shall equal the product of the Transmission Rate Base and the Cost of Capital Rate, as defined in Section II below.
34. **South Georgia Income Tax Adjustment** shall equal an increase in income tax expense that normalizes tax benefits previously flowed through to End Use Customers and for purposes of the BTRREU shall be an annual amount equal to $5,178,000. The final year for the South Georgia Income Tax Adjustment for Federal and State will be 2017.

35. **Total Plant in Service** shall equal SDG&E’s total gross plant balance recorded in FERC Account Nos. 301 through 399.

36. **Transmission Depreciation Reserve** shall equal SDG&E’s transmission reserve balance recorded in FERC Account Nos. 108 and 111.


38. **Transmission Incentive Construction Work in Progress** shall be construction work in progress for which SDG&E is authorized to
collect Incentives under FERC Order No. 679. These costs shall be recorded in FERC Account No. 107.

39. **Transmission Incentive Plant** shall be Transmission Plant for which SDG&E is authorized to collect Incentives under FERC Order No. 679.

40. **Transmission Non-Incentive Plant** shall be Transmission Plant for which SDG&E does not collect Incentives under a project-specific filing under Section 205 of the FPA.

41. **Transmission Operation and Maintenance Expense** shall equal SDG&E’s expenses recorded in FERC Account Nos. 560-573, minus transmission costs currently recorded in FERC Account No. 565 (Transmission of Electricity By Others) relating to the purchase of power on behalf of or to serve SDG&E’s bundled retail customers, minus ISO Grid Management Charge expenses currently recorded in FERC Account No. 561, and minus expenses currently recorded in FERC Account No. 566 that are not transmission related, including, but not limited to, Reliability Must Run and Out of Market Contract Costs, ISO Grid Management Charge expenses, Transmission Revenue Balancing Account
Adjustment ("TRBAA") expenses, and Transmission Access Charge Balancing Account Adjustment expenses.

42. Transmission Plant shall equal SDG&E's Gross Plant balance recorded in FERC Account Nos. 350-359, excluding the portion of any facilities, the cost of which is directly assigned under Section 8.1.2 of SDG&E's TO Tariff.

43. Transmission Plant Held for Future Use shall equal SDG&E's balance recorded in FERC Account No. 105 for projects approved by the CPUC. Gain or loss on the sale of plant held for future use shall be recorded in FERC Account Nos. 411.6 and 411.7.

44. Transmission Related A&G Expenses shall equal (1) SDG&E's Administrative and General Expense included in FERC Account Nos. 920-935, excluding non-transmission-related expenses in FERC Account No. 924 (Property Insurance), FERC Account No. 925 (Damages and Injuries), FERC Account No. 927 (Franchise Requirements), FERC Account No. 930.2 (Miscellaneous General Expenses), and FERC Account No. 935 (Maintenance of General Plant), and any CPUC Intervenor Funding Expense recorded in FERC Account No. 928 (Regulatory Commission Expenses), multiplied by the Transmission Wages and Salaries Allocation.
Factor, plus (2) Property Insurance in FERC Account No. 924, excluding insurance costs related to nuclear plant serving SDG&E’s bundled retail customers, multiplied by the Transmission Plant Property Insurance Allocation Factor, minus (3) CPUC mandated costs recovered through retail rates; provided, however, if the rate(s) of expense accrual for SDG&E’s post-employment benefits other than pensions (“PBOP”), as recorded in FERC Account No. 926, change from those expense levels recorded in SDG&E’s December 1, 2006, filing in Docket Number ER07-284-000, SDG&E may reflect such changes in charges under this formula only to the extent approved by the Commission under Section 205 of the FPA.

35. Transmission Related Amortization of Excess Deferred Tax Liabilities shall equal an amount recorded in FERC Account Nos. 190, 282, and 283 related to transmission as reflected in a footnote in SDG&E’s annual FERC Form 1 as referenced by page in its annual Informational Filing.

36. Transmission Related Amortization of Investment Tax Credits shall equal $522,575 until fully amortized in 2018, plus amortization of any additional investment tax credits related to transmission that may accrue after March 7, 2003. SDG&E shall reflect in a footnote in its annual FERC Form 1 any Transmission Related Amortization...
37. **Transmission Related Cancelled Project Cost** shall equal an amount, other than Valley Rainbow Project Costs, relating to cancelled transmission projects that is recorded in FERC Account No. 182.2. The ratemaking treatment to be afforded such costs shall be determined by the Commission on the basis of a filing made by SDG&E with the Commission under Section 205 of the FPA for recovery under this Appendix VIII. Transmission Related Cancelled Project Cost for the initial Rate Effective Period shall be zero.

38. **Transmission Related Cancelled Project Cost Amortization Expense** shall equal the annual amortization expense recorded in FERC Account No. 407 related to Transmission Related Cancelled Project Cost.

39. **Transmission Related Electric Miscellaneous Intangible Plant Amortization Expense** shall equal SDG&E’s balance recorded in FERC Account No. 404 multiplied by the Transmission Wages and Salaries Allocation Factor.
50. **Transmission Related Municipal Franchise Tax Expense** shall equal: a) the Base Transmission Revenue Requirement (“BTRR”) multiplied by the Municipal Franchise Tax Expense rate that the CPUC authorizes from time to time, currently 1.1%, which shall be recovered as part of the BTRR rates, plus b) an amount of Municipal Franchise Tax Expense that the CPUC authorizes SDG&E to collect from customers who reside in the City of San Diego. This latter amount shall be reflected on the electric bills of customers residing in the City of San Diego.

51. **Transmission Related Payroll Taxes Expense** shall equal SDG&E’s total electric Payroll Taxes expense recorded in FERC Account No. 408.1, multiplied by the Transmission Wages and Salaries Allocation Factor.

52. **Transmission Related Property Taxes** shall equal Property Taxes, excluding property taxes directly assigned to SONGS, multiplied by the Transmission Related Property Tax Allocation Factor. SDG&E shall footnote in its annual FERC Form 1 the directly assigned property taxes attributable to SONGS, which SDG&E shall reference by page in its Informational Filing.
43. **Transmission Related Regulatory Debits** shall equal SDG&E’s amortization expense associated with Other Regulatory Assets/Liabilities debited to FERC Account No. 407.3 that the Commission has accepted for recovery under Section 205 of the FPA. Transmission Related Regulatory Debits for the initial Rate Effective Period shall be zero.

44. **Transmission Related Revenue Credits** shall include Rents Received from Electric Property recorded in FERC Account No. 454 associated with such Electric Property included in Transmission Rate Base as defined in Section II.A below, plus Other Electric Revenues recorded in FERC Account No. 456 that recover the cost associated with SDG&E’s Transmission Rate Base, excluding any revenues credited through the TRBAA or another mechanism.

45. **Transmission Related Uncollectible Expense** shall equal the Base Transmission Revenue Requirement EU multiplied by the allowance for uncollectible expenses approved from time to time by the CPUC. Initially, the rate is 0.266%.
56. **True-Up Period** shall be 12 months ended March 31 of each year; *provided, however,* that the initial True-Up Period shall be the 9 months ending March 31, 2008.

57. **Uncollectible Expense** shall equal SDG&E’s charges for uncollectible accounts recorded in FERC Account No. 904.

58. **Valley Rainbow Project Costs** shall equal $1,892,694, which represents the annual amortization, over a ten-year period, of certain costs associated with the cancelled Valley Rainbow transmission project.

59. **Weighted Forecast Plant Additions** for any Forecast Period shall be the estimated capital investment in new Transmission Plant, Transmission Plant Held for Future Use, and Transmission Related General and Common Plant SDG&E anticipates placing in service during such Forecast Period. Such estimated capital investments shall be determined for each month of the Forecast Period as described herein and each such estimated capital investment shall be multiplied by a weighting factor such that the magnitude of such capital investment as reflected in the determination of SDG&E’s transmission revenue requirement pursuant to this Appendix VIII formula reflects the number of months during the Forecast Period.
those investments in new transmission facilities are actually in service. Any new transmission facilities expected to be placed in service during the Forecast Period but prior to the end of the first month of the following Rate Effective Period, i.e. September 30, shall be assigned a weighting factor of 1.00. Any new transmission facilities expected to be placed in service during the Forecast Period as of the beginning of the second month of the Rate Effective Period, i.e. October 1, or thereafter through and including August 31 of the following year, shall be assigned a weighting factor based on the number of months during the Rate Effective Period for which those facilities are expected to be in service divided by 12. Thus, for example, a plant addition expected to be placed in service in October of the Rate Effective period would be assigned a weighting factor of 11 divided by 12 or 0.917.
II. CALCULATION OF ANNUAL TRANSMISSION REVENUE REQUIREMENTS

A. Return and Associated Income Taxes

Non-Incentive Return and Associated Income Taxes shall equal the product of the Non-Incentive Transmission Rate Base and a Non-Incentive Cost of Capital Rate. Incentive Return and Associated Income Taxes shall equal the product of the Incentive Transmission Rate Base and an Incentive Cost of Capital Rate. These are defined as follows.

1. Transmission Non-Incentive Rate Base

The Transmission Non-Incentive Rate Base will be calculated as follows:

(a) Transmission Non-Incentive Plant based on the average of the thirteen monthly balances, plus

(b) Transmission Related General Plant based on the average of the sum of the beginning and end of year balances, plus

(c) Transmission Related Common Plant based on the average of the sum of the beginning and end of year balances, plus

(d) Transmission related Electric Miscellaneous Intangible Plant based on the average of the sum of the beginning and end of year balances, plus
(e) Transmission Plant Held for Future Use based on the average of the thirteen monthly balances, minus

(f) Transmission Related Depreciation Reserve for Transmission Non-Incentive Plant based on the average of the thirteen monthly balances, minus

(g) Transmission Related Accumulated Deferred Income Taxes for Transmission Non-Incentive Plant based on the average of the thirteen monthly balances, minus

(h) Transmission Related General and Common Accumulated Deferred Taxes based on the average of the sum of the beginning and end of year balances, minus

(i) Transmission Related Miscellaneous Intangible Plant Amortization Reserve based on the average of the sum of the beginning and end of year balances, minus

(j) Transmission Related Miscellaneous Intangible Plant Accumulated Deferred Income Taxes based on the average of the sum of the beginning and end of year balances, plus

(k) Other Regulatory Assets/Liabilities, plus
(l) Transmission Related Prepayments based on the average of the sum of the thirteen monthly balances, plus

(m) Transmission Related Materials and Supplies based on the average of the thirteen monthly balances, plus

(n) Transmission Related Cash Working Capital, plus

(o) Transmission Related Cancelled Project Cost,

Where:

(1) Transmission Non-Incentive Plant shall be as defined in Section I, Definitions.

(2) Transmission Related General Plant shall equal SDG&E’s balance of investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(3) Transmission Related Common Plant shall equal SDG&E’s balance of investment in Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(4) Transmission Related Electric Miscellaneous Intangible Plant shall equal SDG&E’s balance of
Electric Miscellaneous Intangible Plant recorded in
FERC Account No. 303 multiplied by the
Transmission Wages and Salaries Allocation Factor.

(5) **Transmission Plant Held for Future Use** shall be as
defined in Section I, Definitions.

(6) **Transmission Related Depreciation Reserve** for
Transmission Non-Incentive Plant shall equal the
balance of Transmission Depreciation Reserve for
Transmission Non-Incentive Plant plus the balance of
transmission related General Plant Depreciation
Reserve, plus transmission related Common Plant
Depreciation Reserve. Transmission related General
Plant Depreciation Reserve and transmission related
Common Plant Depreciation Reserve shall equal the
product of General Plant Depreciation Reserve plus
Common Plant Depreciation Reserve, and the
Transmission Wages and Salaries Allocation Factor.

(7) **Transmission Related Accumulated Deferred Income
Taxes** shall equal the balance of Total Transmission
Accumulated Deferred Income Taxes applicable to
Transmission Non-Incentive Plant, as reflected in a
footnote to SDG&E’s annual FERC Form 1 which SDG&E shall reference by page in its Informational Filing. Total Transmission Related Accumulated Deferred Income Taxes applicable to Transmission Non-Incentive Plant shall exclude Financial Accounting Standard 109 costs.

(8) **Transmission Electric General and Common Accumulated Deferred Taxes** shall equal SDG&E’s total General and Common Accumulated Deferred Taxes, as reflected in a footnote to SDG&E’s annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing, multiplied by the Transmission Wages and Salaries Allocation Factor. Such Accumulated Deferred Income Taxes shall exclude Financial Accounting Standard 109 costs.

(9) **Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve** shall equal SDG&E’s balance of Electric Miscellaneous Intangible Plant Amortization Expense recorded in FERC Account No. 111, multiplied by the Transmission Wages and Salaries Allocation Factor. SDG&E shall
footnote these amounts in its annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing.

(10) **Transmission Related Electric Miscellaneous**

*Intangible Plant Accumulated Deferred Income Taxes* shall equal SDG&E’s balance of Electric Miscellaneous Intangible Plant Accumulated Deferred Income Taxes recorded in FERC Account Nos. 281-283 and the deferred tax balance recorded in FERC Account No. 190, multiplied by the Transmission Wages and Salaries Allocation Factor. SDG&E shall footnote these amounts in its annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing.

(11) **Transmission Related Other Regulatory Assets/Liabilities** shall equal SDG&E’s electric balance of any Other Regulatory Assets/Liabilities.

(12) **Transmission Related Prepayments** shall equal SDG&E’s electric balance of prepayments multiplied by the Transmission Plant Allocation Factor.
(13) Transmission Related Materials and Supplies shall equal SDG&E’s electric balance of Materials and Supplies multiplied by the Transmission Plant Allocation Factor.

(14) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, and Transmission Related Administrative and General Expense.

(15) Transmission Related Cancelled Project Cost for Non-Incentive Projects shall have the meaning set forth in Section I.B.47 hereof.

2. Transmission Incentive Rate Base

The Transmission Incentive Rate Base shall be calculated as follows:

(a) Transmission Incentive Plant based on the average of the thirteen monthly balances, plus

(b) Transmission Incentive Construction Work in Progress based on the average of the thirteen monthly balances, minus
(c) Transmission Related Depreciation Reserve for Transmission Incentive Plant based on the average of the thirteen monthly balances, minus

(d) Transmission Related Accumulated Deferred Income Taxes applicable to Transmission Incentive Plant based on the average of the thirteen monthly balances, plus

(e) Transmission Related Other Regulatory Assets/Liabilities applicable to Transmission Incentive Plant, based on the average of the thirteen monthly balances,

Where,

(1) Transmission Incentive Plant shall be as defined in Section I, Definitions.

(2) Transmission Incentive Construction Work in Progress shall be as defined in Section I, Definitions.

(3) Transmission Related Depreciation Reserve for Transmission Incentive Plant shall equal the balance of Total Transmission Depreciation Reserve for Transmission Incentive Plant.
(4) Transmission Related Accumulated Deferred Income Taxes applicable to Transmission Incentive Plant shall equal the balance of Total Transmission Accumulated Deferred Income Taxes applicable to Transmission Incentive Plant, as reflected in a footnote to SDG&E’s annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing. Total Transmission Related Accumulated Deferred Income Taxes applicable to Transmission Incentive Plant shall exclude Financial Accounting Standard 109 costs.

(5) Transmission Related Other Regulatory Assets/Liabilities applicable to Transmission Incentive Plant shall equal SDG&E’s electric balance of any Other Regulatory Assets/Liabilities applicable to Transmission Incentive Plant.

3. Non-Incentive Cost of Capital Rate

The Non-Incentive Cost of Capital Rate will equal (a) SDG&E’s Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon end-of-period capital structure and will be equal to the
weighted cost of SDG&E’s (i) long term debt, (ii) preferred stock and (iii) common equity with each such cost being weighted by the percentage that each such capital component is to SDG&E’s total capital. (Thus, for example, if long term debt represents 40.00% of total capital and has a cost of 10.00%, the weighted long term debt cost component would be 4.00%). SDG&E’s total capital shall equal the sum of SDG&E’s balance of long term debt, preferred stock issued and outstanding, and common stock issued and outstanding. The respective costs of these components will be calculated as follows:

(i) the long-term debt component, shall be the actual weighted average embedded cost to maturity of SDG&E’s long-term debt then outstanding.

The actual weighted average embedded cost to maturity of SDG&E’s long-term debt shall equal:

(1) The sum of (a) FERC Account No. 427 - Interest on Long-Term Debt; (b) plus FERC Account No. 428 - Amortization of Debt Discount and Expenses; (c) plus FERC Account No. 428.1 - Amortization of
Unamortized Loss on Reacquired Debt; (d) less
FERC Account No. 429 - Amortization of Premium on
Debt – Credit; and (e) less FERC Account No. 429.1 -
Amortization of Gain on Reacquired Debt – Credit

divided by

(2) the sum of the following accounts: (a) FERC
 Account No. 221 - Bonds; (b) less FERC Account No.
222 - Reacquired Bonds; (c) plus FERC Account No.
224 - Other Long-Term Debt plus (d) FERC Account
No. 225 – Unamortized Premium on Long Term Debt,
less (e) FERC Account No. 226 – Unamortized
Discount on Long Term Debt.

(ii) the preferred stock component, shall be the weighted
cost to maturity of SDG&E’s preferred stock and shall
be computed as the ratio of the total cost recorded in
FERC Account No. 437 - Dividends Declared –
Preferred Stock, to the total Preferred Stock Issued as
recorded in FERC Account No. 204.
the Non-Incentive Return on Equity component, shall be as follows:

(a) Non-Incentive Return on Equity shall be 13.0%, which includes up to 50 basis points of Return on Equity for participation in the ISO, subject to the zone of reasonableness established in Docket No. ER07-284.

(b) Non-Incentive Return on Equity shall be applied to proprietary capital as shown on page 112 of FERC Form 1, less FERC Account No. 204 – Preferred Stock Issued, found on line 3 of said page.

(b) Federal Income Tax shall equal

\[
(A + \left[\frac{(C-B)}{D}\right])(FT) \\
1 - FT
\]

where:

FT is the Federal Income Tax Rate in effect on July 1 of each year;

A is the sum of the preferred stock component and the Non-Incentive Return on Equity component, as determined in Sections II.A.2.a.(ii) and (iii) above;
B is Transmission Related Amortization of Investment Tax Credits and Transmission Related Amortization of Excess Deferred Tax Liabilities, as determined in Sections I.B.45 and I.B.46 above;

C is the Equity AFUDC Component of Transmission Depreciation Expense and shall equal the amount of Transmission Depreciation Expense related to the Equity AFUDC Component of Transmission Plant; and

D is Transmission Non-Incentive Rate Base, as determined in Section II.A.1, above.

(c) State Income Tax shall equal

\[
(A + \frac{(C-B)}{D} + \text{Federal Income Tax})(ST) \times \frac{1}{1 - ST}
\]

where:

ST is the State Income Tax Rate in effect on July 1 of each year;

A is the sum of the preferred stock component and Non-Incentive Return on Equity component determined in Sections II.A.2.a.(ii) and (iii) above;

B is the Transmission Related Amortization of Investment Tax Credits and Transmission Related
Amortization of Excess Deferred Tax Liabilities, as
determined in Section I.B.45 and I.B.46, above;

C is the equity AFUDC Component of Transmission
Depreciation Expense and shall equal the amount of
Transmission Depreciation Expense related to the Equity
AFUDC Component of Transmission Plant; and

D is the Transmission Rate Base, as determined in
Section II.A.1, above and Federal Income Tax is the rate
determined in Section II.A.2.b above.

4. Incentive Cost of Capital Rate

The Incentive Cost of Capital Rate shall be defined the same as the
Non-Incentive Cost of Capital Rate except that the Incentive Return
on Equity rate shall be an Incentive Return on Equity. In addition,
Transmission Non-Incentive Rate Base, as used in II.A (b) D, shall
be changed to Transmission Incentive Rate Base.

B. End Use Customer Base Transmission Revenue Requirement

End Use Customer Base Transmission Revenue Requirement ("BTRREU")
for a given Rate Effective Period shall be:

\[ BTRREU = PYRREU + FCEU +/- True-Up Adjustment \]
where

\[ PYRR_{EU} = PYRR_{EU-IR} + PYRR_{EU-NIR} \]

and where:

B.1 \( PYRR_{EU-NIR} \) for \( BTRR_{EU} \), excluding Incentive costs, shall be determined on the basis of transmission cost data recorded in Form 1 and underlying ledger accounts for the prior year and such other costs and information provided in SDG&E’s annual Informational Filing and shall be calculated as follows:

(A) Return and Associated Income Taxes applicable to Transmission Non-Incentive Plant, plus

(B) Depreciation Expense for Transmission Plant applicable to Transmission Non-Incentive Plant, plus

(C) Transmission, General, and Common Plant Depreciation Expense, plus

(D) Transmission related Electric Miscellaneous Intangible Plant Amortization Expense, plus

(E) Transmission Related Regulatory Debits applicable to the calculation of Non-Incentive revenue, minus

(F) Transmission Related Amortization of Investment Tax Credits, minus
(G) Transmission Related Amortization of Excess Deferred Tax Liabilities, plus

(H) Transmission Related Payroll Taxes Expense, plus

(I) Transmission Related Property Taxes, plus

(J) Transmission Operation and Maintenance Expense, plus

(K) Transmission Related A&G Expenses, plus

(L) Valley Rainbow Project Costs and Transmission Related Cancelled Project Cost, minus

(M) Transmission Related Revenue Credits, plus

(N) Transmission Related Municipal Franchise Tax Expense, plus

(O) Transmission Related Uncollectible Expense, plus

(P) CPUC Intervenor Funding Expense, plus

(Q) South Georgia Income Tax Adjustment.

(R) Gains and losses on the sale of Transmission Plant Held for Future Use.
B.2 \( \text{PYRR}_{EU IR} \) for Transmission Incentive Plant shall be determined from records maintained individually for each Incentive Project and shall be calculated as follows:

(A) Return and Associated Income Taxes applicable to Transmission Incentive Plant and Transmission Incentive Construction Work in Progress, plus

(B) Depreciation Expense for Transmission Plant applicable to Transmission Incentive Plant, plus

(C) Transmission Related Regulatory Debits applicable to Transmission Incentive Plant, plus

(D) Transmission Related Municipal Franchise Expense applicable to Transmission Incentive Plant, plus

(E) Transmission Related Uncollectible Expense applicable to Transmission Incentive Plant.

B.3 Forecast Period Capital Addition Revenue Requirements ("FC\(_{EU}\)"") shall be the product of Weighted Forecast Plant Additions and an Annual Fixed Charge Rate ("AFCR").

B.3.1 Forecast Period Capital Addition Non-Incentive Revenue Requirements shall be calculated as follows:
\[ FC_{EU-NIR} = \text{Weighted Forecast Plant Additions excluding Transmission Plant Held for Future Use} \times AFCR_{EU-NIR} \]

where:

\( AFCR_{EU-NIR} \) shall be the Annual Fixed Charge Rate for purposes of determining the amount of revenue requirements for Non-Incentive revenue associated with Weighted Forecast Plant Additions to be included in the determination of \( BTRR_{EU} \), and is calculated as follows:

\[ AFCR_{EU-NIR} = PYR_{EU-NIR} \times \text{South Georgia Income Tax Adjustment} + \text{Transmission Related Amortization of Investment Tax Credit} + \text{Transmission Related Amortization of Excess Deferred Tax Liability} - \text{Valley Rainbow Project Costs} \]

\[ \div \text{sum of Transmission Non-Incentive Plant, transmission related General Plant, and transmission related Common Plant and transmission related Electric Miscellaneous Intangible Plant balances} \]

\[ \text{(which said balances, in each instance, shall be calculated in accordance with 18 CFR Section 35.13).} \]

B.3.1.1 Revenue requirements for Transmission Plant Held for Future Use during the Forecast Period for Non-Incentive Projects shall be determined by multiplying a Non-Incentive Cost of Capital Rate by Forecast Period Transmission Plant Held for Future Use for Non-Incentive Projects using the same weighting method that is
used for determining the revenue requirements for Weighted Forecast Plant Additions. In addition, Transmission Non-Incentive Rate Base, as used in II.A.3.(b) D, shall be changed to weighted Transmission Plant Held for Future Use.

B.3.2 Forecast Period Capital Addition Incentive Revenue Requirements for Incentive Projects that receive only an Incentive Return on Equity shall be calculated as follows:

\[
F_{CEU-IR-ROE} = \text{Weighted Forecast Plant Additions} \times AFC_{REU-IR-ROE}
\]

where:

\[
AFC_{REU-IR-ROE} \text{ shall be calculated using the methodology in II.B.3.1 above, using Transmission Non-Incentive Plant as if it were Transmission Incentive Plant and substituting the Non-Incentive Cost of Capital Rate with the Incentive Cost of Capital Rate.}
\]

B.3.3 Forecast Period Capital Addition Incentive Revenue Requirements for Incentive Projects that receive both an Incentive Return on Equity and an accelerated depreciation Incentive shall be calculated as follows:

\[
F_{CEU-IR-ROE-AD} = \text{Weighted Forecast Plant Additions} \times AFC_{REU-IR-ROE-AD}
\]
where:

\[ \text{AFCR}_{\text{EU-IR-ROE-AD}} \] shall be calculated using the methodology shown in II.B.3.1 above, using Transmission Non-Incentive Plant as if it were Transmission Incentive Plant.

1. Accelerated depreciation shall be calculated by multiplying the accelerated depreciation rate by existing gross Transmission Non-Incentive Plant and substituting Depreciation Expense for Transmission Plant, General Plant Depreciation Expense, and Common Plant Depreciation Expense with the accelerated depreciation expense.

2. Additionally, the Non-Incentive Cost of Capital Rate shall be substituted by the Incentive Cost of Capital Rate.

B.3.4 For Transmission Incentive Construction Work in Progress during the Forecast Period, revenue requirements shall be calculated by applying an Incentive Cost of Capital Rate to forecasted Transmission Incentive Construction Work in Progress using the same weighting method that is used for determining the revenue requirements for Weighted Forecast Plant Additions. In addition, Transmission Non-Incentive Rate Base, as used in II.A.3.(b) D, shall be changed to weighted Transmission Incentive Construction Work in Progress.
B.4 True-Up Adjustment shall be calculated in accordance with Section II.D below.

C. ISO Base Transmission Revenue Requirement

ISO Base Transmission Revenue Requirement (“BTRRISO”) for a given Rate Effective Period shall be:

\[ BTRR_{ISO} = PYR_{ISO} + FC_{ISO} +/- \text{True-Up Adjustment} \]

where

\[ PYR_{ISO} = PYR_{ISO-IR} + PYR_{ISO-NIR} \]

and where:

C.1 PYR_{ISO-NIR} for BTRR_{ISO}, excluding Incentive costs, shall be determined on the basis of transmission cost data recorded in Form 1 and underlying ledger accounts for the prior year and such other costs and information provided in SDG&E’s annual Informational Filing and shall be calculated as follows:

(A) Return and Associated Income Taxes applicable to Transmission Non-Incentive Plant, plus

(B) Depreciation Expense for Transmission Plant applicable to Transmission Non-Incentive Plant, plus
(C) Transmission, General, and Common Plant Depreciation Expense, plus

(D) Transmission related Electric Miscellaneous Intangible Plant Amortization Expense, plus

(E) Transmission Related Regulatory Debits applicable to the calculation of Non-Incentive revenue, minus

(F) Transmission Related Amortization of Investment Tax Credits, minus

(G) Transmission Related Amortization of Excess Deferred Tax Liabilities, plus

(H) Transmission Related Payroll Taxes Expense, plus

(I) Transmission Related Property Taxes, plus

(J) Transmission Operation and Maintenance Expense, plus

(K) Transmission Related A&G Expenses, plus

(L) Valley Rainbow Project Costs and Transmission Related Cancelled Project Cost, minus

(M) Transmission Related Revenue Credits, plus
(N) Transmission Related Municipal Franchise Tax Expense.

(O) Gains and losses on the sale of Transmission Plant Held for Future Use.

C.2 PYRR_{ISO-IR} for Transmission Incentive Plant shall be determined from records maintained individually for each Incentive Project and shall be calculated as follows:

(A) Return and Associated Income Taxes applicable to Transmission Incentive Plant and Transmission Incentive Construction Work in Progress, plus

(B) Depreciation Expense for Transmission Plant applicable to Transmission Incentive Plant, plus

(C) Transmission Related Regulatory Debits applicable to Transmission Incentive Plant, plus

(D) Transmission Related Municipal Franchise Expense applicable to Transmission Incentive Plant.

C.3 Forecast Period Capital Addition Revenue Requirements ("FC_{ISO"}) shall be the product of Weighted Forecast Plant Additions and an Annual Fixed Charge Rate ("AFCR").
C.3.1 Forecast Period Capital Addition Non-Incentive Revenue

Requirements shall be calculated as follows:

\[ FC_{ISO-NIR} = \text{Weighted Forecast Plant Additions excluding Transmission Plant Held for Future Use} \times AFCR_{ISO-NIR} \]

where:

AFCR_{ISO-NIR} shall be the Annual Fixed Charge Rate for purposes of determining BTRR_{ISO-NIR} used to calculate High Voltage and Low Voltage Access Charges applicable to Non-Incentive revenue, and shall be calculated as follows:

\[ AFCR_{ISO-NIR} = PYRR_{ISO-NIR} + \text{Transmission Related Amortization of Investment Tax Credits} + \text{Transmission Related Amortization of Excess Deferred Tax Liabilities} - \text{Valley Rainbow Project Costs} - \text{any Transmission Related Cancelled Project Cost that the Commission determines shall be amortized as an expense, divided by the sum of Non-Incentive Transmission Plant, plus transmission related General Plant, plus Transmission Related Common Plant, plus Transmission Related Electric Miscellaneous Intangible Plant balances (which balances, in each instance, shall be calculated in accordance with 18 CFR Section 35.13).} \]

C.3.1.1 Revenue requirements for Transmission Plant Held for Future Use during the Forecast Period for Non-Incentive Projects
shall be determined by multiplying a Non-Incentive Cost of Capital Rate by Forecast Period Transmission Plant Held for Future Use for Non-Incentive Projects using the same weighting method that is used for determining the revenue requirements for Weighted Forecast Plant Additions. In addition, Transmission Non-Incentive Rate Base, as used in II.A.3.(b) D, shall be changed to weighted Transmission Plant Held for Future Use.

C.3.2. Forecast Period Capital Addition Incentive Revenue Requirements for Incentive Projects that receive only an Incentive Return on Equity shall be calculated as follows:

$$FC_{\text{ISO-IR-ROE}} = \text{Weighted Forecast Plant Additions} \times AFCR_{\text{ISO-IR-ROE}}$$

where:

$AFCR_{\text{ISO-IR-ROE}}$ shall be calculated using the methodology in II.C.3.1 above, using Transmission Non-Incentive Plant as if it were Transmission Incentive Plant and substituting the Non-Incentive Cost of Capital Rate with the Incentive Cost of Capital Rate.

C.3.3 Forecast Period Capital Addition Incentive Revenue Requirements for Incentive Projects that receive both an Incentive Return on Equity and an accelerated depreciation Incentive shall be calculated as follows:
FC_{ISO-IR-ROE-AD} = \text{Weighted Forecast Plant Additions} \times \text{AFCR}_{ISO-IR-ROE-AD}

where:

\text{AFCR}_{ISO-IR-ROE-AD} \text{ shall be calculated using the methodology shown in II.C.3.1 above, using Transmission Non-Incentive Plant as if it were Transmission Incentive Plant.}

(1) Accelerated depreciation shall be calculated by multiplying the accelerated depreciation rate by existing gross Transmission Non-Incentive Plant and substituting Depreciation Expense for Transmission Plant, General Plant Depreciation Expense, and Common Plant Depreciation Expense with the accelerated depreciation expense.

(2) Additionally, the Non-Incentive Cost of Capital Rate shall be substituted by the Incentive Cost of Capital Rate.

C.3.4 For Transmission Incentive Construction Work in Progress during the Forecast Period, revenue requirements shall be calculated by applying an Incentive Cost of Capital Rate to forecasted Transmission Incentive Construction Work in Progress using the same weighting method that is used for determining the revenue requirements for Weighted Forecast
Plant Additions. In addition, Transmission Non-Incentive Rate Base, as used in II.A.3.(b) D, shall be changed to weighted Transmission Incentive Construction Work in Progress.

C.4 \( BTRR_{ISO} \) shall be further allocated between HV Transmission Facility revenue requirements (“\( BTRR_{ISO-HV} \)”) and LV Transmission Facility revenue requirements (“\( BTRR_{ISO-LV} \)”) as follows:

i. \( BTRR_{ISO-HV} = BTRR_{ISO} \times \text{allocation factors applicable to HV Transmission Facilities as described in the Existing and New HV and LV Allocation Factors} \)

ii. \( BTRR_{ISO-LV} = BTRR_{ISO} \times \text{allocation factors applicable to LV Transmission Facilities as described in the Existing and New HV and LV Allocation Factors} \)

C.5 True-Up Adjustment shall be calculated in accordance with Section II.D below.

D. **True-Up Adjustment shall be calculated as follows:**

1. **Derivation of True-Up Adjustment** - SDG&E will derive two True-Up Adjustments one applicable to End Use Customers (“\( TU_{AEU} \)”) and one applicable to ISO wholesale customers (“\( TU_{AISO} \)”). Such True-Up Adjustments shall equal the following:
The sum of monthly revenues ("TUR") recorded during the True-Up Period minus the sum of monthly true-up cost of service ("TUCS") during the True-Up Period.

Such True-Up Adjustments shall be calculated for each month of the True-Up Period and adjusted for Interest as described below.

2. **Derivation of the True-Up Cost of Service applicable to the True-Up Period**

In order to derive the End Use True-Up Cost of Service ("TUCS_{EU}\) and Wholesale True-Up Cost of Service ("TUCS_{ISO}\) for any True-Up Period, SDG&E shall determine its cost of providing transmission service for that True-Up Period using the cost of service methodology described in Sections II.B and II.C of this Appendix VIII, and shall distribute that TUCS_{EU} and TUCS_{ISO} respectively, to each month of the True-Up Period by stating its True-Up Cost of Service on an average annual rate and multiplying said annual average rate times the actual recorded monthly determinants for each month of the True-Up Period, as more fully described below. Pursuant to the methodology set forth in Appendix IX, SDG&E shall compute the following to derive the TUCS_{EU} and the TUCS_{ISO}:
a. The TUCS\textsubscript{EU} for each month of the True-Up Period for each class of service specified in Appendix IX of SDG&E’s Transmission Owner Tariff shall be calculated by dividing the TUCS\textsubscript{EU} for the True-Up Period by the annual billing determinants for that customer class and multiplying the resulting amount by the recorded monthly billing determinants for that customer class for that month.

b. The TUCS\textsubscript{ISO} for each month of the True-Up Period for each class of service specified in Appendix IX of SDG&E’s Transmission Owner Tariff shall be calculated by dividing the TUCS\textsubscript{ISO} for the True-Up Period by the annual billing determinants, as measured at transmission voltage level, for that customer class and multiplying the resulting amount by the recorded monthly billing determinants, as measured at transmission voltage level, for that customer class for that month.

3. Derivation of True-Up Revenues during the True-Up Period:

SDG&E shall determine for each month of the True-Up Period the following:

a. True-Up Revenues for the End Use Customers (“TUR\textsubscript{EU}”) shall equal the total transmission revenues SDG&E recorded for each month of the True-Up Period as received from End Use Customers.

b. True-Up Revenues for ISO wholesale customers (“TUR\textsubscript{ISO}”) shall equal the following:
1. for the first five months of the True-Up Period (April through August) the ISO True-Up revenues will equal for each class of service as specified in Appendix IX of SDG&E’s Transmission Owner’s Tariff, true-up transmission rates in effect during this period multiplied by the End Use Customer recorded billing determinants, as measured at transmission voltage level for each month of this period. The true-up transmission rates by the class of service will equal the $BTRR_{ISO}$ in effect during this period allocated (using the class allocation factor as described in Appendix IX) to each class of service, divided by the class of service billing determinants applicable to this $BTRR_{ISO}$.

2. for the last seven months of the True-Up Period (September through March) the ISO true-up revenues will equal for each class of service as specified in Appendix IX of SDG&E’s Transmission Owner’s Tariff, true-up transmission rates in effect during this period multiplied by the End Use Customer recorded billing determinants, as measured at the transmission voltage level, for each month of this period. The true-up transmission rates by class of service will equal the $BTRR_{ISO}$ in effect during this period allocated (using the class allocation factor as described in Appendix IX) to each class of service, divided by the class of service billing determinants applicable to this $BTRR_{ISO}$.
4. **Derivation of Interest Related to Over and Under Recovery of Costs:**

For each month of the True-Up Period, for any over- or under-recovery of its costs as determined by comparing TUCS and TUR, SDG&E shall calculate an applicable amount of Interest pursuant to 18 CFR Section 35.19a.

5. **Interest True-Up Adjustment**

   a. The Interest True-Up adjustment for any formula cycle filing shall be calculated for the current cycle True-Up Period in two parts. First, for the current cycle filing, SDG&E shall take the previous cycle True-Up Adjustment overcollection (undercollection) balance and calculate the interest that accrues on this balance for the first five months of the current True-Up Adjustment Period (April 1 through August 31). SDG&E shall calculate the interest amount pursuant to 18 CFR Section 35.19, by compounding the related interest on a quarterly basis.

   b. Second, interest shall be calculated monthly on the unamortized overcollection (undercollection) balance of the sum of the interest that occurred in the first five months as calculated in (a) above plus the previous cycle True-Up Adjustment balance. The monthly amortized balance will be calculated for the remaining period from September 1 to March August 31 of the current cycle Rate Effective Period.
Period. The monthly amount by which the balance decreases will be calculated by multiplying an amortization rate per kWh times each month's retail sales in kWs. The amortization rate per kWh will be calculated by taking the beginning overcollection/(undercollection) balance as of the start of the rate effective period and dividing it by the kWs in the current Rate Effective Period. The kWs in the Rate Effective Period shall equal the first seven months actual and the last five month forecast.

c. The interest in parts (a) and (b) above for an overcollection (undercollection) balance shall be summed and credited to the current cycle formula True-Up Adjustment. In the event interest is determined on an undercollection balance in part (a) and (b) above, such interest shall be added to the current cycle True-Up Adjustment.

d. The unamortized Interest True-Up Adjustment balance from the current Interest True-Up Adjustment (balance as of March 31) will be carried forward to the following cyclic filing and used as the beginning monthly unamortized balance beginning the first month of the True-Up Adjustment Process (April). This unamortized balance shall be amortized over the remaining months of the current cycle Rate Effective Period months (April through August).
Monthly interest on the unamortized balance for these months will then be calculated. This interest will then be added to the interest calculated as part of the following cycle's True-Up Adjustment. In the following cycle filing, the process described in items (a) through (c) shall be repeated including the calculation of interest described in item (d) above. Note should be made that in the following cyclic filing's Interest True-Up Adjustment process the interest calculations described in items (c) and (d) will overlap for the first five months of the Interest True-Up calculation process (April through August).
APPENDIX IX

DETERMINATION OF SDG&E'S END USE CUSTOMER CLASS TRANSMISSION CHARGES, LOW VOLTAGE ACCESS CHARGE, AND HIGH VOLTAGE UTILITY-SPECIFIC RATE, AND ALLOCATION OF BTRR APPLICABLE TO HIGH VOLTAGE AND LOW VOLTAGE TRANSMISSION FACILITIES

I. INTRODUCTION

This Appendix IX describes the method by which SDG&E:

1. allocates Base Transmission Revenue Requirements (as determined in Appendix VIII) to End Use Customer classes, and designs transmission rates applicable to such End Use Customer classes assessed by SDG&E pursuant to this TO Tariff;
2. allocates Base Transmission Revenue Requirements (as determined in Appendix VIII) applicable to High Voltage Transmission Facilities and Low Voltage Transmission Facilities for purposes of designing voltage-differentiated Wheeling Access Charges assessed pursuant to the ISO Tariff;
3. calculates the applicable Low Voltage Access Charge to be assessed pursuant to SDG&E's Transmission Owner Tariff (TO Tariff); and
4. calculates a High Voltage Utility-Specific Rate.

SDG&E shall provide the ISO its determination of the High Voltage Utility-Specific Rate, as updated annually pursuant to the formula rate contained in Appendix VIII of this TO Tariff, for use by the ISO to calculate the High Voltage Wheeling Access Charge assessed by the ISO pursuant to the ISO Tariff. SDG&E shall also provide the ISO SDG&E’s determination of the Low Voltage Wheeling Access Charge that is assessed by the ISO pursuant to the ISO Tariff.
A. END-USE CUSTOMER CLASSES FOR TRANSMISSION SERVICE:

The following applies only to End-Use Customers that receive transmission service over the ISO Controlled Grid through SDG&E's transmission or distribution facilities. End-Use Customers shall take service under the following rate designations:

- Residential
- Small Commercial
- Medium and Large Industrial
- Street Lighting
- Stand-by Service

Rates applicable to the current Rate Effective Period shall be posted on SDG&E’s OASIS, which can be accessed at www.sdge.com\toforum. The rates are also assessable through a link to SDG&E’s web page that is located at the CAISO OASIS at www.caiso.com.
B. DERIVATION OF SDG&E’S END-USE CUSTOMER TRANSMISSION RATES:

The transmission rate components of SDG&E’s End-Use Customer rates are determined as follows:

1. Allocate the Base Transmission Revenue Requirements applicable to End Use Customers (BTRREU) under the TO Tariff as calculated pursuant to the formula rate contained in Appendix VIII of SDG&E’s TO Tariff among End-Use Customer rate classes based upon the most recent 10-year coincident peak data averaged by month to derive the 12-month average coincident peak data adjusted to reflect distribution losses to the transmission level.
2. To mitigate the impact of rate increases to Street Lighting and Stand-by Service classes, the rates effective October 1, 2003, for these customer classes shall be limited to a 100% rate increase under the otherwise applicable rate design. Beginning with rates that become effective July 1, 2004, SDG&E shall design transmission rates applicable to Street Lighting and Stand-by Service classes based on total cost of service without such mitigation measures. The revenue requirement under-recovery attributable to this mitigation measure that occurs during the first Rate Effective Period shall be allocated among other customer classes in proportion to these classes’ respective contribution to SDG&E’s 12-month average coincident peak excluding the contribution to such coincident peak from Street Lighting and Stand-by Service classes.

3. Divide the results of the allocation described paragraph “1”, as adjusted by paragraph “2” above, by the appropriate forecast End Use Customer billing determinants applicable to the Rate Effective Period to determine the transmission prices for the respective End Use Customer classes.
End Use Customer classes shall be determined in accordance with SDG&E’s CPUC tariffs. The billing determinants used to design transmission rates applicable to End Use Customer classes shall be as follows:

a. Residential – forecast metered energy (kwh) for the Rate Effective Period;

b. Small Commercial – forecast metered energy (kwh) for the Rate Effective Period;

c. Medium and Large Industrial – forecast metered maximum non coincident peak demand (kw) for the Rate Effective Period;

d. Street Lighting – forecast energy (kwh) used by all lamps in service for the Rate Effective Period;

e. Stand-by Service – contract demands (kw) applicable to Stand-by Service for the Rate Effective Period.
C. ALLOCATION OF SDG&E'S BASE TRANSMISSION REVENUE REQUIREMENTS AND DERIVATION OF UTILITY SPECIFIC HIGH VOLTAGE TRANSMISSION RATE AND LOW VOLTAGE RATES APPLICABLE TO LOW VOLTAGE WHEELING ACCESS CHARGE:

1. The Base Transmission Revenue Requirements applicable to Wheeling Access Charges pursuant to the ISO Tariff (hereinafter referred to as the “BTRR\textsubscript{ISO}”) shall be allocated among the following:

   a) Existing High Voltage (HV) Transmission Facilities, i.e. High Voltage Transmission Facilities that were in service prior to January 1, 2001

   b) Existing Low Voltage (LV) Transmission Facilities, i.e. Low Voltage Facilities that went into service prior to January 1, 2001

   c) New High Voltage (HV) Transmission Facilities, i.e. High Voltage Facilities that went into service after December 31, 2000

   d) New Low Voltage (LV) Transmission Facilities, i.e. Low Voltage Facilities that were in service after December 31, 2000.
2. The revenue requirement associated with the Transmission Balancing Account Adjustment (TRBAA) shall be allocated between Existing and New Transmission Facilities in accordance with the following:

a) Existing HV and Existing LV Transmission Facilities

b) New HV Transmission Facilities and New LV Transmission Facilities

3. The HV Utility Specific transmission rate shall be derived by taking the portion of BTRR_{ISO} attributable to HV Transmission Facilities, divided by total retail forecast kwh billing determinants (adjusted for distribution losses) applicable during the Rate Effective Period.

4. SDG&E’s Low Voltage Access Charge and Low Voltage Wheeling Access Charge shall be derived by taking the portion of BTRR_{ISO} attributable to LV Transmission Facilities, divided by SDG&E’s forecast Gross Load applicable during the Rate Effective Period.