Application of SAN DIEGO GAS & ELECTRIC COMPANY For Authority to Update Marginal Costs, Cost Allocation, And Electric Rate Design (U 902-E))

Application No. 07-01-__
Exhibit No.: (SDGE-07) ________

PREPARED DIRECT TESTIMONY

OF DAVID A. BORDEN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

JANUARY 31, 2007

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PREPARED DIRECT TESTIMONY

OF

DAVID A. BORDEN

CHAPTER 7

I. INTRODUCTION

The purpose of my testimony is to present current rate design methodologies for medium and large (M&L) commercial and industrial (C&I) (including large agricultural), and standby rate classes, to present rate design proposals and implementation details that support San Diego Gas and Electric Company's (SDG&E) revenue allocation proposals, to present rate change exhibits, and to present changes to terms and conditions in rate schedules concerning reconnection charges, minimum bills, and combined billing of multiple meters at a single location and for a single entity. My testimony describes: (1) proposed revisions to distribution unit charges for recovery of the allocated revenue requirement presented by SDG&E witness Parsons in Chapters 4 & 5; and, (2) proposed revisions to commodity unit charges to comport with the generation marginal cost study and revenue allocation proposals presented by SDG&E witness Parsons in Chapters 4 & 5. The rate design proposals are designed to collect the total revenues proposed in the General Rate Case (GRC) Phase 1, when combined with the rate design proposals of SDG&E witnesses Claffey (Residential, Small Commercial, and Agriculture) in Chapter 6 and SDG&E witness Fang (Street Lighting) in Chapter 8.

My testimony is organized as follows:

- Current and Proposed Rate Design Methodologies (Section II)
    - Overview of Rate Design Proposals (Section A)

- Medium & Large (M&L) Commercial and Industrial (C&I), Including Large Agricultural, Rate Design Proposals (Section B)
- Standby Rate Design Proposals (Section C)
- Miscellaneous Rate Proposals (Section D)

- Exhibits (Section III)

II. CURRENT AND PROPOSED RATE DESIGN METHODOLOGIES

A. Overview of Rate Design Proposals

1. Cost Based Rates

The main principal adhered to in designing the M&L C&I rates is that the rates be cost based. Cost based rates send appropriate price signals to customers. To the extent possible, and based on the customer class allocation of the overall revenue requirement as set forth in the testimony of SDG&E witness Parsons in Chapter 5, SDG&E's M&L C&I rate design moves rates closer to their full cost basis.

2. Rate Design and Marginal Cost Studies

The proposed M&L C&I rate designs are based on the marginal customer and marginal distribution demand cost studies presented by SDG&E witness Parsons in Chapter 4, and the marginal generation capacity and energy studies presented by SDG&E witness Parsons in Chapter 4, scaled for revenue requirement recovery as presented by SDG&E witness Parsons in Chapter 5.

3. Rate Design Components

The rate components addressed are the components that make up the distribution and commodity rates, e.g., distribution demand charges, basic service fees, and generation demand and energy charges. SDG&E maintains its current structure for M&L C&I of distribution demand charges based upon non-coincident demand. SDG&E proposes to implement a commodity demand charge (current commodity charges are recovered through energy only charges) in conjunction with commodity energy charges for M&L C&I class. SDG&E proposes a $/kWh charge to the distribution component, applicable to all M&L C&I kWhs, (including Secondary Substation, Primary Substation, and Transmission Level), in order to recover the program costs associated with the California Solar Initiative (CSI), Self Generation Incentive Programs (SGIP), hazardous substance cleanup costs, AMI Infrastructure costs, and the Advanced Metering and Demand Response Program costs, currently allocated to the M&L C&I class, from all M&L C&I customers, as explained in the testimony of SDG&E witness Hansen, Chapter 2. The Competition Transition Charge (CTC) for M&L C&I is changed from its current demand charge structure to an energy only charge.

4. Rate Design & GRC Phase 1 Revenue Requirement

The M&L C&I rate design moves towards cost based rates while recovering the allocated share of the 2008 Test Year GRC Phase 1 proposed revenue requirement. In other words, the proposed rate designs for the M&L C&I class are revenue neutral compared to the 2008 Test Year GRC Phase 1 proposed revenue requirement .

5. Commodity Critical Peak Pricing and Advanced Metering Infrastructure

Commodity rates for Critical Peak Pricing (CPP) in conjunction with the implementation of Advanced Metering Infrastructure (AMI) for the M&L C&I class are discussed in the testimony of SDG&E witness Magill in Chapter 10.

B. M&L C&I Rate Design Proposals

M&L C&I rate design proposals for distribution are a continuation of the existing structure (i.e. there is no change in distribution system design[1]) except for the inclusion of $/kWh charge to recover the costs of programs and services as explained in the testimony of SDG&E witness Hansen, Chapter 2. Distribution charges, which are predominantly non-coincident peak demand charges, are increased according to each rate schedules' contribution to the overall M&L C&I uncapped revenue requirement allocation (excluding Schedule S, Standby, which is calculated separately). The methodology for allocating distribution revenue requirement is based on each customer class' contribution to marginal distribution cost and then scaled for the difference between marginal cost and the proposed revenue requirement based on the Equal Percentage of Marginal Cost (EPMC) methodology. The process is described in greater detail and sponsored by SDG&E witness Parsons in Chapter 5. Basic service fees are set well below full cost of service levels, as determined in the marginal customer cost study sponsored by SDG&E witness Parsons in Chapter 4, and are increased by 20% over their current level. A 20% increase in basic service fees is warranted in order to make progress toward cost based rates, and this percentage level is within a range of reasonableness of the system overall percentage increase to distribution rates.

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[1] SDG&E's distribution system is of a radial design, meaning that there is no single main distribution line serving distribution load and that system design is influenced more by localized non-coincident demands rather than system wide coincident demand.

Commodity rates for M&L C&I customers are based upon the marginal capacity and energy costs as set forth in the cost studies sponsored by SDG&E witness Parsons in Chapter 4. Marginal generation capacity costs are based on the average of the top 300 hours for three years of system wide peak demand by rate schedule (for those with available billing determinants). SDG&E proposes capacity charges in the form of demand charges based upon the M&L C&I class' contribution to system peak. The use of demand charges to recover capacity costs is a significant change from SDG&E's current rate design which recovers M&L C&I capacity costs on a $/kWh basis. However, generation demand charges are not a significant development in the area of rate design, especially for commercial and industrial customer classes. In fact, both Southern California Edison Company (SCE) and Pacific Gas & Electric Company (PG&E) employ generation demand charges for their M&L C&I customers. The demand charge sends the appropriate long-term price signal regarding generation capacity costs to customers given that capacity needs are a function of customer demand and capacity is generally provided through investment in generation plants that is relatively fixed. Ideally, a generation demand charge is calculated on a coincident peak basis for all applicable rate schedules because SDG&E must have sufficient generation capacity (owned or contracted) to meet the system coincident peak, but SDG&E currently does not have coincident peak billing determinants for each rate schedule and thus calculates demand charges for the rate schedules based on the available determinants. As advanced metering technology is deployed to the M&L C&I class, SDG&E will begin to transition toward coincident peak demand charges for the entire M&L C&I class of customers. In allocating capacity costs to M&L C&I, the capacity costs are allocated to each rate schedule according to the variation in coincident peak demand by time of use, e.g., peak, semi-peak, and off-peak, voltage level, and season (summer/winter). Regarding seasonal demand charges, greater than 90% of the capacity costs are recovered through the summer demand charge and a small amount is recovered in a modest winter demand charge. The winter demand component reflects the inclusion of October in winter months and the slight probability that the system peak could occur in October. Once seasonal periods are adjusted to include October in the summer period (as proposed in this proceeding) then the winter demand charge will be removed. SDG&E's proposed demand charge for M&L C&I is applied to the customers applicable demand in a given month, according to the terms set forth in their applicable rate schedule, i.e., the billing demands vary by month and are not ratcheted. Given the significant bill impacts that result from employing the generation demand charges, SDG&E proposes that the charges be set at 50% of their calculated cost of service.

Commodity rates that recover marginal energy costs are designed to recover the full marginal energy costs (including any scaling factors needed for class revenue requirement allocation) by rate schedule as determined by SDG&E witness Parsons in Chapters 4 & 5. The marginal energy costs reflect rate schedule hourly loads for weekday and weekend profiles for each month. The annual average marginal energy cost is scaled according to 24 hourly price shapes. Marginal energy costs are then allocated according to rate schedule, voltage, time-of-use periods (peak, semi-peak, and off-peak), and on a seasonal basis (summer/winter), based upon the respective share of energy usage.

In summary, regarding marginal generation costs, the main change is the implementation of a demand charge to recover marginal capacity costs (marginal capacity costs are currently recovered through an energy charge from all M&L C&I rate schedules) for each rate schedule. Although SDG&E supports movement to cost based rates, the bill impacts resulting from a generation demand charge will be significant at full cost and thus SDG&E proposes that generation demand charges be set initially at 50% of cost and that they not be ratcheted charges. The overall revenue impact to M&L C&I is an approximate 5% reduction in marginal generation cost recovery when compared to existing rates.

SDG&E proposes a non-bypassable distribution charge, based on $/kWh and applicable to all M&L C&I customers, including those served at transmission level only, primary substation, and secondary substation in order to recover the costs associated with programs and services whose costs are required to be recovered from all customers, or that the programs and services provide a system benefit to all customers. Currently, SDG&E recovers the M&L C&I portion of these costs in the distribution demand charges and thus transmission level only, primary substation, and secondary substation customers effectively by-pass these costs. SDG&E does not propose an increase in assignment of these costs to M&L C&I as a whole, but proposes an intra-class allocation of existing M&L C&I cost assignment such that transmission level only, primary substation, and secondary substation customers contribute to cost recovery. The intra-class allocation recovers the costs assigned to M&L C&I (on an EPMC basis) on an equal cents per kWh basis from all kWhs, including those at transmission level only, primary substation, and secondary substation.

SDG&E proposes to re-design CTC charges in a revenue neutral fashion (by general rate class) in order to replace existing CTC demand charges with $/kWh charges. This is consistent with accepted California Public Utilities Commission (Commission) practice of recovering non-bypassable costs from all customers through a $/kWh charge. Under this proposal the M&L C&I class is allocated the same share of CTC revenue requirement as approved in the 2006 RDW proceeding and the existing demand charges are eliminated and replaced by an equal cents per kWh rate that is applicable to all kWhs of M&L C&I usage. Given that forecasted sales are higher for GRC 2 compared to the 2006 RDW authorized forecast there is a slight decrease in CTC rates.

1. Schedule AL-TOU

Schedule AL-TOU is the largest rate schedule, in terms of customers and sales, in the M&L C&I class. This schedule is available to all M&L C&I customers and about 94% of total M&L C&I sales (excluding transmission level sales) are on this rate schedule. Currently, distribution rates for Schedule AL-TOU are based on marginal distribution costs from SDG&E's prior Rate Design Window (RDW) proceeding filed in February 2005 and made effective in February 2006, pursuant to Decision (D.) 05-12-003. The distribution rates consist of basic service fees that vary according to voltage level and demand levels and distance adjustment, and demand charges that are determined according to non-coincident peak (NCP) demand and maximum peak demand by season (summer/winter) and voltage level. SDG&E proposes no changes to this structure in this proceeding. SDG&E's proposed distribution charges for

Schedule AL-TOU are based on the marginal costs as calculated in the marginal customer and marginal distribution demand cost studies sponsored by SDG&E witness Parsons in Chapter 4. The proposed distribution rates are designed to recover the full marginal cost, scaled for total class revenue requirement recovery as presented by SDG&E witness Parsons in Chapter 5.

Schedule AL-TOU commodity rates currently recover marginal capacity and energy costs (scaled for the currently authorized commodity revenue requirement) through $/kWh charges that vary according to voltage level, season, and time-of-use periods (peak, semi-peak, and off-peak). SDG&E proposes a monthly maximum on-peak demand charge based on $/kW to recover marginal generation capacity costs. When Schedule AL-TOU coincident peak demand determinants become available (in the future through the implementation of advanced capability meters) then the capacity costs will be recovered through a coincident peak demand charge, but until such time maximum on-peak demand are the determinants that are available. (Schedule AY-TOU and Schedule PA-T-1 generation demand charges are also based on maximum on-peak demand determinants and will transition to coincident peak with the implementation of advanced capability meters.) The calculation of marginal generation capacity costs is briefly described previously in my testimony and is sponsored in the testimony of SDG&E witness Parsons in Chapter 4.

The Schedule AL-TOU energy component is designed to recover the marginal energy costs according to season, time-of-use, and voltage levels. The calculation of marginal energy costs is briefly described previously in my testimony and is sponsored in the testimony of SDG&E witness Parsons in Chapter 4.

The CTC for Schedule AL-TOU is re-designed such that the CTC demand charge is replaced with an energy only charge. As stated previously in this testimony, the energy charge is the same cents per kWhs rate applicable to all M&L C&I customers and derived from the same CTC revenue requirement approved in the 2006 RDW proceeding.

A non-bypassable $/kWh distribution charge is added to Schedule AL-TOU to recover the costs of programs and services, as described in the testimony of SDG&E witness Hansen Chapter 2, from all M&L C&I customers including transmission level only, primary substation, and secondary substation customers. Current demand charges were decreased and replaced with a $/kWh charge that is equal for all M&L C& I customers.

The bill impacts for Schedule AL-TOU, by season and customer demand level, are set forth on Schedule AL-TOU – Summer – Attachment SMC-17 and Schedule AL-TOU – Winter – Attachment SMC-18.

2. Schedule AY-TOU

Schedule AY-TOU is an optional time-of-use rate applicable to M&L C&I customers whose maximum annual demands do not exceed 500 kW. The rate schedule was closed to new customers as of September 2, 1999.

Currently, distribution rates for Schedule AY-TOU are based on marginal distribution costs from SDG&E's prior RDW proceeding filed in February 2005 and made effective February 2006, pursuant to D.05-12-003. The distribution rates consist of basic service fees that vary according to voltage level, and demand charges that are determined according to NCP demand and maximum peak demand by season (summer/winter) and voltage level. SDG&E proposes no changes to this structure in this proceeding. SDG&E's proposed distribution charges for Schedule AY-TOU are based on the marginal distribution costs as calculated in the marginal customer and marginal distribution demand cost studies sponsored by SDG&E witness Parsons in Chapter 4. The proposed distribution rates are designed to recover the full marginal cost, scaled for total class revenue requirement recovery as presented by SDG&E witness Parsons in Chapter 5.

Schedule AY-TOU commodity rates currently recover marginal capacity and energy costs (scaled for the currently authorized commodity revenue requirement) through $/kWh charges that vary according to voltage level, season, and time-of-use periods (peak, semi-peak, and off-peak) and are identical to Schedule AL-TOU commodity rates. SDG&E proposes marginal capacity and energy rates for Schedule AY-TOU that are identical to the rates proposed for Schedule AL-TOU. The methodology for calculating these charges has been discussed previously in my testimony.

The CTC for Schedule AY-TOU is re-designed such that the CTC demand charge is replaced with an energy only charge. As stated previously in this testimony, the energy charge is the same cents per kWhs rate applicable to all M&L C&I customers and derived from the same CTC revenue requirement approved in the 2006 RDW proceeding.

A non-bypassable charge is added to Schedule AY-TOU to recover the costs of programs and services, as described in the testimony of SDG&E witness Hansen Chapter 2, from all M&L C&I customers including transmission level only, primary substation, and secondary substation customers. Current demand charges were decreased and replaced with a $/kWh charge that is equal for all M&L C& I customers.

3. Schedule PA-T-1

Schedule PA-T-1 is applicable to agricultural customers with maximum monthly demands expected to exceed 500 kW and with other qualifications. Currently, distribution rates for Schedule PA-T-1 are based on marginal distribution costs from SDG&E's prior Rate Design Window (RDW) proceeding filed in February 2005 and made effective in February 2006, pursuant to D.05-12-003. The distribution rates consist of a single basic service fee, and demand charges that are determined according to various time-of-use options. Options C-F utilize NCP demand and each option provides some variation on time-of-use periods. Charges vary according to summer/winter and voltage level. SDG&E proposes no changes to this structure in this proceeding. SDG&E's proposed distribution charges for Schedule PA-T-1 are based on the marginal distribution costs as calculated in the marginal customer and marginal distribution demand cost studies sponsored by SDG&E witness Parsons in Chapter 4. The proposed distribution rates are designed to recover the full marginal cost, scaled for total class revenue requirement recovery as presented by SDG&E witness Parsons in Chapter 5.

Schedule PA-T-1 commodity rates currently recover marginal capacity and energy costs (scaled for the currently authorized commodity revenue requirement) through $/kWh charges that vary according to voltage level, season, and time-of-use periods (peak, semi-peak, and off-peak) and are identical to Schedule AL-TOU commodity rates. SDG&E proposes marginal energy rates for Schedule PA-T-1 that are identical to the rates proposed for Schedule AL-TOU. SDG&E proposes a monthly maximum on-peak demand charge for Schedule PA-T-1 that is based on the marginal generation capacity costs utilizing the top 300 hour approach as described in the testimony of SDG&E witness Parsons in Chapter 4. The methodology for calculating these charges has been discussed previously in my testimony.

The CTC for Schedule PA-T-1 is re-designed such that the CTC demand charge is replaced with an energy only charge. As stated previously in this testimony, the energy charge is the same cents per kWhs rate applicable to all M&L C&I customers and derived from the same CTC revenue requirement approved in the 2006 RDW proceeding.

A non-bypassable charge is added to Schedule PA-T-1 to recover the costs of programs and services, as described in the testimony of SDG&E witness Hansen Chapter 2, from all M&L C&I customers including transmission level only, primary substation, and secondary substation customers. Current demand charges were decreased and replaced with a $/kWh charge that is equal for all M&L C& I customers.

4. Schedule AD

Schedule AD is a demand meter rate that has been closed to new customers for nearly 20 years. Schedule AD distribution rates are based on marginal distribution costs from SDG&E's prior RDW proceeding filed in February 2005 and made effective in February 2006, pursuant to D.05-12-003. The distribution rates consist of a basic service fee and demand charges that are determined according to maximum demand by voltage level. SDG&E proposes no changes to this structure in this proceeding. SDG&E's proposed distribution charges for Schedule AD are based on the marginal distribution costs as calculated in the marginal customer and marginal distribution demand cost studies sponsored by SDG&E witness Parsons in Chapter 4. The proposed distribution rates are designed to recover the full marginal cost, scaled for total class revenue requirement recovery as presented by SDG&E witness Parsons in Chapter 5.

Schedule AD commodity rates currently recover marginal capacity and energy costs (scaled for the currently authorized commodity revenue requirement) through a $/kWh. SDG&E proposes marginal capacity and energy rates for Schedule AD that are based on the results of the marginal capacity and energy cost studies. The marginal capacity costs will be recovered through a maximum demand charge, given that maximum demands are the available determinants. With the implementation of advanced capability meters these charges should transition to coincident peak as the determinants become available. The methodology for calculating these charges has been discussed previously in my testimony.

The CTC for Schedule AD is re-designed such that the CTC demand charge is replaced with an energy only charge. As stated previously in this testimony, the energy charge is the same cents per kWhs rate applicable to all M&L C&I customers and derived from the same CTC revenue requirement approved in the 2006 RDW proceeding.

A non-bypassable charge is added to Schedule AD to recover the costs of programs and services, as described in the testimony of SDG&E witness Hansen Chapter 2, from all M&L C&I customers including transmission level only, primary substation, and secondary substation customers. Current demand charges were decreased and replaced with a $/kWh charge that is equal for all M&L C& I customers.

5. Schedule A6-TOU

Schedule A6-TOU is an optional time-of-use rate applicable to M&L C&I customers whose maximum annual demands in any time period exceeds 500 kW. Currently, distribution rates for Schedule A6-TOU are based on marginal distribution costs from SDG&E's prior RDW proceeding filed in February 2005 and made effective in February 2006, pursuant to D.05-12-003. The distribution rates consist of basic service fees that vary according to voltage levels and distance adjustment, and demand charges that are determined according to NCP demand and maximum peak demand by season (summer/winter) and voltage level. SDG&E proposes no changes to this structure in this proceeding. SDG&E's proposed distribution charges for Schedule A6-TOU are based on the marginal distribution costs as calculated in the marginal customer and marginal distribution demand cost studies sponsored by SDG&E witness Parsons in Chapter 4. The proposed distribution rates are designed to recover the full marginal cost, scaled for total class revenue requirement recovery as presented by SDG&E witness Parsons in Chapter 5 and are equivalent to the rates calculated for Schedule AL-TOU.

Schedule A6-TOU commodity rates currently recover marginal capacity and energy costs (scaled for the currently authorized commodity revenue requirement) through $/kWh charges that vary according to voltage level, season, and time-of-use periods (peak, semi-peak, and off-peak) and are equivalent to AL-TOU. SDG&E proposes a monthly coincident peak demand charge based on $/kW to recover marginal generation capacity costs. The calculation of marginal generation capacity costs is briefly described previously in my testimony and is sponsored in the testimony of SDG&E witness Parsons in Chapter 4.

The Schedule A6-TOU energy component is designed to recover the marginal energy costs according to season, time-of-use, and voltage levels. The calculation of marginal energy costs is briefly described previously in my testimony and is sponsored in the testimony of SDG&E witness Parsons in Chapter 4.

The CTC for Schedule A6-TOU is re-designed such that the CTC demand charge is replaced with an energy only charge. As stated previously in this testimony, the energy charge is the same cents per kWhs rate applicable to all M&L C&I customers and derived from the same CTC revenue requirement approved in the 2006 RDW proceeding.

A non-bypassable charge is added to Schedule A6-TOU to recover the costs of programs and services, as described in the testimony of SDG&E witness Hansen Chapter 2, from all M&L C&I customers including transmission level only, primary substation, and secondary substation customers. Current demand charges were decreased and replaced with a $/kWh charge that is equal for all M&L C& I customers.

C. Standby Rate Design Proposals

1. Standby Service

Standby service is generally provided in three forms: 1) backup, 2) maintenance, and 3) supplemental service.

Backup service is needed when a customer's own generation experiences an unexpected outage. SDG&E provides backup service up to the contract level of demand through its standby rates set forth on Schedule S and through the waiver of the non-coincident distribution demand charge on the otherwise applicable rate schedule. The vast majority of SDG&E's standby load is otherwise served on Schedule AL-TOU. SDG&E believes that the rates for standby service set forth on Schedule S are below cost of service. In the 1990s, SDG&E's standby rates were about 80% of the Schedule AL-TOU non-coincident demand charge and currently they are about 53% of the Schedule AL-TOU non-coincident demand charge. The Schedule S movement to further below the cost based rate of Schedule AL-TOU was likely the result of rate settlements over time and not a reflection of benefits provided by standby customers through load diversity. In order to provide diversity benefits, the Standby customer must provide "physical assurance," which is the application of devices and equipment that interrupt a distributed generation customer's normal load when distributed generation does not operate[2]. Currently, no Standby customers provide physical assurance. In addition to physical assurance, a Standby customer may provide diversity benefits through location, size and number such that SDG&E is able to defer distribution capacity additions. In 2001 SDG&E examined its distribution system and determined that there were no distributed generators on its distribution system that

[2] See D.01-07-027, pg. 58

met these criteria. Based on communications with the SDG&E witness responsible for the 2001 report, I understand that the number of distributed generators has increased since 2001 but the circumstance has not changed regarding diversity benefits and that currently there are no distributed generators on the SDG&E system that have allowed SDG&E to defer distribution capacity additions. Since Standby customers do not provide physical assurance and do not provide the benefit of deferred distribution capacity, standby customers do not provide a diversity benefit and their rate for backup should be moved closer to the cost of service rate on Schedule AL-TOU. In order for today's Schedule S rates to equal the Schedule AL-TOU rates, the rates would have to be increased approximately 45%. Since other SDG&E rate proposals (generation demand charge and the proposed CPP rate) may also affect standby customers, and the magnitude of the effect is uncertain because it is not yet known how standby customers may change their operations, SDG&E proposes that Schedule S rates be increased by the same percentage as the overall system average increase that is proposed.

Another approach to providing standby backup service is to segregate the distribution costs into fixed costs that do not vary with usage and that should be recovered through the standby demand charge, and backup service that is associated with costs that may vary with usage and are recovered via an energy only rate. Although SDG&E believes that the costs of its distribution service are predominantly fixed in nature and recoverable through its proposed demand charges, the Commission has authorized this type of fixed and variable rate structure for standby service. (If a standby customer were to provide physical assurance then the demand charge would be waived up to the level of load covered by the physical assurance.) SDG&E believes that an 80/20 split between fixed and variable charges could be appropriate for this type of standby rate structure. Using the Schedule AL-TOU non-coincident demand charge as the cost based rate, implementing a standby demand charge of 80% of the Schedule AL-TOU rate would require an increase of approximately 25% over existing standby rates. In order to mitigate the rate impact, and given that other SDG&E rate proposals may affect standby customers, SDG&E proposes to move the Standby rate closer to the 80% level of the Schedule AL-TOU demand charge by increasing the existing Schedule S rates by the overall system average increase in revenues at the time of filing.

Maintenance service under Schedule S is currently provided via waiver of the otherwise applicable or companion schedules' non-coincident distribution demand billing up to the contract level of demand for approved maintenance outages. With respect to maximum on-peak demand charges, SDG&E currently waives the distribution demand billings for such charges only to the extent that SDG&E has approved in advance the scheduled outage (SDG&E does not approve maintenance outages for the summer period). SDG&E proposes no changes in maintenance service.

Supplemental service is provided for service above the contract level of demand and is provided at the otherwise applicable scheduled rates. SDG&E proposes no changes to supplemental service.

Standby customers currently pay for commodity costs through $/kWh energy rates on their otherwise applicable rate schedules. SDG&E proposes a demand charge to recover the capacity costs associated with commodity and Standby customers are subject to the same commodity demand charges to the extent that their onsite generation does not serve all of their load during summer peak periods. SDG&E's summer demand charges are designed to recover the commodity capacity costs over the 5 month summer period. To the extent that onsite generation is operated during a summer month or a summer peak period, the customer's diversity in generation may allow standby customers to avoid a portion of this demand charge. SDG&E will not provide a waiver of summer peak period generation demand charges for standby customers because SDG&E does not provide advanced approval of maintenance outages in summer months. If a standby customer takes service under SDG&E's proposed Critical Peak Pricing (CPP) rate there will not be a waiver of the Capacity Reservation Charge and usage in excess of the CRC during CPP events will be billed at CPP energy rates as described in the testimony of SDG&E witness Magill, Chapter 10.

D. Miscellaneous Rate Design Proposals

a. Reconnection Charge and Minimum Bill or Charge

SDG&E has Reconnection Charges, Minimum Bills, and Minimum Charges contained within its tariffs. SDG&E proposes to make the terminology consistent within its tariffs and to make sure that application is consistent within each class of customer.

1. Reconnection Charge Language

Currently, SDG&E has a Reconnection Charge on its Rate Schedules to address cases such as seasonal customers where the customer may otherwise terminate service and restart service at the same location one, or more, times a year. The Reconnection Charge causes such a customer to pay the Minimum Bill for all months in the prior year that they did not pay it upon reconnection at the same location within a year of termination.

2. Statement of Presently Effective Language for Reconnection Charge:

SDG&E's Rate Schedules address Reconnection Charges as follows:

SCHEDULE DR, DR-TOU, DM, DS, DT, DT-RV, DR-TOU-DER, EV-TOU, EV-TOU-2, EV-TOU-3, LS-1, LS-2, LS-3, OL-1, DWL, UM

No language is contained addressing a Reconnection Charge.

SCHEDULE A, A-TC, AD, A-TOU, AL-TOU-DER, AY-TOU, A6-TOU, PA, PA-T-1,

"Special Condition

4. Reconnection Charge: In the event that a customer terminates service under this schedule and reinitiates service under this or any other schedule at the same location within 12 months, there will be a Reconnection Charge equal to the minimum charge which would have been billed had the customer not terminated service."

SCHEDULE AL-TOU, AL-TOU-CP

"Special Condition

4. Reconnection Charge: In the event that a customer terminates service under this schedule and reinitiates service under this or any other schedule at the same location within 12 months, there will be a Reconnection Charge equal to the greater of the Minimum Charge or the Basic Service Fee which would have been billed had the customer not terminated service."

3. Reconnection Charge Language Change Proposal

To the extent possible, SDG&E proposes to make the language consistent between the tariffs and to reduce the tariff language where practical, while ensuring that its Rate Schedules maintain sufficient requirements to mitigate the potential of customers gaming the rates through seasonal termination and re-commencement of service. In reviewing other utility approaches SDG&E has become aware that SCE, in its Schedule GS-2, has language in Special Condition 9 that succinctly describes reconnection conditions as: "…Any customer resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued."

As described in the next section, SDG&E proposes using SCE's above cited language in SDG&E's tariffs, either as a new addition or as a change to existing Reconnection Charge language, including to the recently approved Schedule UM.

4. Statement of Proposed Language for Reconnection Charge:

SCHEDULE DR, DR-TOU, DM, DS, DT, DT-RV, DR-TOU-DER, EV-TOU, EV-TOU-2, EV-TOU-3, LS-1, LS-2, LS-3, OL-1, DWL

No Reconnection Charge language.

SCHEDULE A, A-TC, AD, A-TOU, AL-TOU, AL-TOU-DER, AL-TOU-CP, AY-TOU, A6-TOU, PA, PA-T-1,

Replace existing language with the following, or add the following as new language.

"Special Condition

4. Reconnection Charge: Any customer resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued."

5. Minimum Bill or Charge Language

SDG&E presently has a Minimum Bill or Minimum Charge language in many of its Rate Schedules. In some cases the language tells how to book the revenue from the billing of the Minimum Charge. In others it is used as a definition that then is used in determining the amount of a Reconnection Charge (see above discussion).

6. Statement of Presently Effective Language for Minimum Bill or Charge:

SCHEDULE DR, DR-TOU, DM, DS, DT, DT-RV, DR-TOU-DER, EV-TOU, EV-TOU-2, EV-TOU-3,

"Minimum Bill

Rate components of the minimum charge, including charges associated with Schedule EECC Electric Energy Commodity Cost), will be calculated based on average minimum bill usage."

SCHEDULE A, A-TC, PA, PA-T-1,

"Minimum Charge

The minimum charge shall be the Basic Service Fee."

SCHEDULE A-TOU

"Minimum Charge

The minimum monthly charge shall be the sum of the Service Charges."

Rate Schedules that do not have either Minimum Charge or Minimum Bill Language

AD, AL-TOU, AL-TOU-DER, AL-TOU-CP, AY-TOU, A6-TOU, UM, LS-1, LS-2, LS-3, OL-1, DWL

7. Proposal:

SDG&E proposes to retain the Minimum Bill language in its Residential Rate Schedules in its current form and, provided that SDG&E's proposal regarding the Reconnection Charge language is adopted, eliminate language regarding a Minimum Bill in all other Rate Schedules containing it.

8. Statement of Proposed Language for Minimum Bill or Charge:

SCHEDULE DR, DR-TOU, DM, DS, DT, DT-RV, DR-TOU-DER, EV-TOU, EV-TOU-2, EV-TOU-3

Retain the current language.

"Minimum Bill

Rate components of the minimum charge, including charges associated with Schedule EECC , will be calculated based on average minimum bill usage."

SCHEDULE A, A-TC, PA, PA-T-1, A-TOU

Delete language regarding Minimum Charge.

SCHEDULE AD, AL-TOU, AL-TOU-DER, AL-TOU-CP, AY-TOU, A6-TOU, UM, LS-1, LS-2, LS-3, OL-1, DWL

Leave without any language on Minimum Charge or Minimum Bill.

b. Combined Billing of Meters on Single Premise Owned by Same Entity

SDG&E has a provision in Schedules AL-TOU and AL-TOU-DER that permits a customer that has load at multiple meters on a single premise to have those meters treated as though they were a single meter. SDG&E proposes to simplify and clarify this language.

1. Combined Billing of Meters on Single Premise Owned by Same Entity

SDG&E has a provision in Schedules AL-TOU and AL-TOU-DER that permits a customer that has load at multiple meters on a single premise to have those meters treated as though they were a single meter. The provision requires that the customer pays a fixed monthly fee for the wiring that SDG&E has in place between the multiple meters. In addition the provision requires that the customer pay for meters to capture 15-minute load information and that the customers have all the same billing components applied to all meters that are combined.

SDG&E proposes to simplify the language in the special conditions, move some of the language to Rule 1, Definitions, and to clarify two points in the language so that it is clear that a customer's premise must be all within a single governmental jurisdiction and that the customer may not use the tariff for point to point wheeling. In addition, the rate to be applied needs to be updated to more accurately reflect costs.

2. Special Condition Language

Special Condition 16 of Schedule AL-TOU and Special Condition 15 of Schedule AL-TOU-DER set forth the terms for the combining of multiple meters on a single premise. These special conditions set forth the specific conditions for service when combining multiple meters on a customer's single premise.

3. Statement of Presently Effective Language for Special Condition 16:

The following language is contained in SDG&E's Rate Schedules addressing Reconnection Charges:

Special Condition 16 of SCHEDULE AL-TOU and 15 of AL-TOU-DER

"Multiple Meters on Single Premise. When a single corporate entity owns a contiguous property, not divided by any public right of way or property owned by another entity, and the utility has more than one meter serving that property, then, at the customer's request the utility will for the additional fees set forth in this Special Condition bill all of the usage at some, or all, of the meters as though the whole premise were served through a single meter. As of September 21, 2004, for new customers to be eligible for combined billing, all meters must have the same billing components. These components include but are not limited to FTA, Large Customer CTC Adjustment, Large Customer Commodity Credit, Direct Access (DA) Cost Responsibility Surcharge, DA Utility Service Credit, DA Energy Charge and DA Franchise Fee Surcharge. Meter data will be combined for the purpose of billing Utility Distribution Company (UDC) charges, as listed in the Rates Section of this tariff. The customer must pay for the utility to install and maintain meters to record consumption in 15 minute intervals for all involved meters. The customer must also pay a distance adjustment fee determined by the utility that is based on the distance between each of the meters involved using normal utility position to determine that distance. The rate applied will be the

Distance Adjustment Fee from the Rate Section of this tariff times 0.121. When Secondary level and Primary level services are combined, the usage measured at the Secondary level will be increased by 4% for losses, prior to being added to the usage measured at the Primary level. When Primary level and Transmission level services are combined, usage measured at the Primary Level will be increased by 3% for losses, prior to being added to the usage measured at the Transmission level."

No other rate schedule contains the above language.

4. Proposal

The first sentence of the proposed language makes clear that the meters involved with the special condition must all be served within the same governmental agencies jurisdiction. This language avoids the suggestion that SDG&E have to allocate revenues from a customer for determination of franchise fees between governmental agencies.

The second and third sentences are maintained to continue to require that the customer's meters that are being combined are all billed the same components, thus avoiding the need for SDG&E to determine how to allocate the combined load of the customer between different charges. For example, if one meter was receiving DA service and another was not then there would be considerable confusion in combining the two meters for any billing purpose. Similar confusion would arise under each of the other possible different billing components identified in the existing and proposed language.

The existing language regarding the responsibility of the customer to pay for the cost of meters needed to combine the meters for billing is proposed to be continued in the fourth sentence.

The sentences addressing the distance adjustment fee application is proposed to be continued with minor wording clarifications. The multiplier of 0.121 is unchanged.

The language dealing with voltage adjustments is proposed to be removed from the special conditions and placed in Rule 1, definitions, as the approach is the same between the tariffs and is thus more appropriately found in the definitions.

5. Statement of Proposed Language:

Redlined from the Presently Effective Language.

Special Condition 16 of SCHEDULE AL-TOU and 15 of AL-TOU-DER

"Multiple Meters on Single Premise. When a single corporate entity owns a contiguous property, not divided by any public right of way or property owned by another entity, <u>all within the same governmental agency's jurisdiction,</u> and the utility has more than one meter serving that property, then, at the customer's request the utility will for the additional fees <u>and conditions</u> set forth in this Special Condition bill all of the usage at some, or all, of the meters as though the whole premise were served through a single meter.

As of September 21, 2004, for new customers to be eligible for combined billing, all meters must have the same billing components. These components include but are not limited to FTA, Large Customer CTC Adjustment, Large Customer Commodity Credit, DA Cost Responsibility Surcharge, DA Utility Service Credit, DA Energy Charge and DA Franchise Fee Surcharge. Meter data will be combined for the purpose of billing UDC charges, as listed in the Rates Section of this tariff.

The customer must pay for the utility to install and maintain meters to record consumption in 15 minute intervals for all involved meters.

The customer must also pay a distance adjustment fee determined by the utility that is based on the distance between each of the meters involved using normal utility position to determine that distance. The rate applied will be the Distance Adjustment Fee from the Rate Section of this tariff multiplied by ~~times~~ 0.121.

~~When Secondary level and Primary level services are combined, the usage measured at the Secondary level will be increased by 4% for losses, prior to being added to the usage measured at the Primary level. When Primary level and Transmission level services are combined, usage measured at the Primary Level will be increased by 3% for losses, prior to being added to the usage measured at the Transmission level."~~

New Definition for Rule 1:

"COMBINED SERVICE VOLTAGE: Combined Service Voltage occurs when two or more meters are used to determine a customers billing. In such a case an adjustment shall be made to the metered information between the voltages prior to billing. When Secondary and Primary voltages are combined, the metered data from Secondary will be increased by 4% prior to being added to the metered data at Primary level. When Primary and Transmission voltages are combined, metered data from Primary will be increased by 3% prior to being added to the metered data from Transmission. Where SDG&E, at the customer's expense, has conducted a customer specific loss study it may apply a percentage other than above. When an alternative percentage is developed it may be rounded to the nearest whole percentage."

c. Replacement of Standard Industrial Classifications with North American Industry Classification System for Customer Applicability for Schedule PA and Schedule PA-T-1

Customer applicability in SDG&E's tariffs for agricultural service, Schedule PA and Schedule PA-T-1, is currently determined, in part, by the economic activity of the customer through the customer's Standard Industrial Classification (SIC). It is my understanding that the SIC was developed in the 1930s in order to help measure economic activity. In 1997, the Office of Management and Budget adopted the North American Industry Classification System (NAICS) for the statistical agencies of the United States and as a replacement for the SIC. The NAICS standardizes industry classifications across Canada, Mexico, and the United States and classifies industry according to the same or similar economic processes. SDG&E's proposal updates the Schedule PA and Schedule PA-T-1 applicability requirements to reflect the currently accepted national standard.

1. Current SIC Customer Applicability Requirements Schedule PA:

<u>APPLICABILITY</u>

…This schedule is available to agricultural customers who are classified with Standard Industrial Classification (SIC)/Codes 01, 02, 4941, 4952, or 4971.

2. Proposed NAICS Customer Applicability Requirements Schedule PA:

<u>APPLICABILITY</u>

…This schedule is available to agricultural customers who are classified with North American Industry Classification System (NAICS)/Codes 11, 22131, or 22132.

3. Current SIC Customer Applicability Requirements Schedule PA-T-1:

<u>APPLICABILITY</u>

…This schedule is available to agricultural customers whose maximum monthly demand is expected to be above 500 kw and who are classified with Standard Industrial Classification (SIC)/Codes 01, 02, 13, 4941, 4952, 4961, or 4971.

4. Proposed NAICS Customer Applicability Requirements Schedule PA-T-1:

APPLICABILITY

…This schedule is available to agricultural customers whose maximum monthly demand is expected to be above 500 kw and who are classified with North American Industry Classification System (NAICS)/Codes 11, 211111, 211112, 213111, 22131, 22132, or 22133.

III. EXHIBITS

The bill impacts for Schedule AL-TOU, by season and customer demand level, are set forth on Schedule AL-TOU – Summer – Attachment SMC-17 and Schedule AL-TOU – Winter – Attachment SMC-18.

This concludes my prepared direct testimony.

IV. QUALIFICATIONS OF DAVID A. BORDEN

My name is David A. Borden and my business address is 8330 Century Park Court, San Diego, California 92123. I am currently employed by San Diego Gas & Electric as a Principal Regulatory Economic Advisor. My responsibilities include electric rate design. I assumed my current position in July 2005. Prior to my current position I served as a Senior Economic Analyst in the Energy Policy Division of the Illinois Commerce Commission (ICC), from January 2000 – July 2005. In my role with the Energy Policy Division I testified in cases before the ICC concerning the electric, natural gas, and water industries. I worked in several other positions at the ICC, including Executive Assistant to Commissioner Richard Kolhauser, and testified in numerous proceedings. My principal responsibilities at SDG&E include electric rate design, revenue and rate projections, and cost of service functions. I previously filed testimony before the CPUC in SDG&E's Application U 902-E for Adoption of its 2007 Energy Resource Recovery Account (ERRA) Forecast Revenue Requirement and Review of its Power Procurement Balancing Account. I have participated on behalf of SDG&E in Rulemaking 02-01-011 Regarding Direct Access and Departing Load Cost Responsibility Surcharge Obligations.

In 1986 I graduated from the University of Texas at Austin with a Bachelor of Arts Degree in Economics. In 1989 I graduated from Texas A&M University, College Station, Texas, with a Master of Science Degree in Economics.